CONOCOPHILLIPS
Form 10-K
February 23, 2011

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2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

(Mark One)

[x] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2010**

OR

[ ] 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.

[x] Yes [ ] 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.

[ ] Yes [x] 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.

[x] Yes [ ] 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).

[x] Yes [ ] 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. [x]

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 [x]	Accelerated filer [ ]	Non-accelerated filer [ ]	Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

[ ] Yes [x] No

The aggregate market value of common stock held by non-affiliates of the registrant on June 30, 2010, the last business day of the registrant s most recently completed second fiscal quarter, based on the closing price on that date of $49.09, was $72.8 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 827,349 and 37,798,903 shares, respectively, in determining the aggregate market value.

The registrant had 1,429,647,979 shares of common stock outstanding at January 31, 2011.

Documents incorporated by reference:

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 11, 2011 (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 anticipate, estimate, believe, budget, continue, could, intend, may, pl predict, seek, should, will, would, expect, objective, projection, forecast, goal, guidance, outl 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 65.

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, bitumen, natural gas, liquefied natural gas (LNG) and natural gas liquids 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 investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. At December 31, 2010, our ownership interest was 2.25 percent based on issued shares. See Note 6 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for information on sales of LUKOIL shares.

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.

At December 31, 2010, ConocoPhillips employed approximately 29,700 people.

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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, 2010, our E&P segment represented 63 percent of ConocoPhillips total assets. This segment primarily explores for, produces, transports and markets crude oil, bitumen, natural gas and natural gas liquids on a worldwide basis. Operations to liquefy natural gas and transport the resulting LNG are also included in the E&P segment. At December 31, 2010, 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, Qatar and Russia.

The E&P segment does not include the financial results or statistics from our 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 following net proved reserves table, for periods before we ceased using equity-method accounting for this investment, which occurred at the end of the third quarter of 2010.

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.

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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 75 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. See Management s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that will enhance the understanding of the table below.

	Millions of Barrels of Oil Equivalent		
Net Proved Reserves at December 31	**2010**	2009	2008
Crude oil and natural gas liquids			
Consolidated operations	**3,161**	3,194	3,340
Equity affiliates	**231**	1,710	1,677
Total Crude Oil and Natural Gas Liquids	**3,392**	4,904	5,017
Natural gas			
Consolidated operations	**3,039**	3,161	3,360
Equity affiliates	**580**	880	798
Total Natural Gas	**3,619**	4,041	4,158
Bitumen			
Consolidated operations	**455**	417	100
Equity affiliates	**844**	716	700
Total Bitumen	**1,299**	1,133	800
Synthetic oil			
Consolidated operations	**-**	248	-
Equity affiliates	**-**	-	-
Total Synthetic Oil	**-**	248	-
Total consolidated operations	**6,655**	7,020	6,800
Total equity affiliates	**1,655**	3,306	3,175
Total company	**8,310**	10,326	9,975
Includes amounts related to LUKOIL investment:	***-***	*1,967*	*1,893*
Excludes Syncrude mining-related reserves (synthetic oil):	***n/a***	*n/a*	*249*

In 2010, E&P s worldwide production, including its share of equity affiliates, averaged 1,752,000 barrels of oil equivalent per day (BOED), compared with 1,854,000 BOED in 2009. During 2010, 686,000 BOED were produced in the United States, a 9 percent decrease from 755,000 BOED in 2009. Production from our international E&P operations averaged 1,066,000 BOED in 2010, a 3 percent decrease from 1,099,000 BOED in 2009. Worldwide production decreased primarily due to field decline, the impact of higher prices on production sharing arrangements and the sale of our Syncrude oil sands mining operation. These decreases were partially offset by production from major projects in China, Canada, Qatar, the Lower 48 and Australia.

E&P s worldwide annual average crude oil and natural gas liquids sales price increased 31 percent, from $55.63 per barrel in 2009 to $72.77 per barrel in 2010. Worldwide bitumen prices increased 18 percent, from $44.84 per barrel in 2009 to $53.06 per barrel in 2010. E&P s average annual worldwide natural gas sales price increased 14 percent, from $4.37 per thousand cubic feet in 2009 to $4.98 per thousand cubic feet in 2010.

E&P UNITED STATES

In 2010, U.S. E&P operations contributed 40 percent of E&P s worldwide liquids production and 39 percent of natural gas production, compared with 40 and 41 percent in 2009, respectively.

Alaska

Greater Prudhoe Area

The Greater Prudhoe Area includes 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 113,000 barrels per day in 2010, compared with 119,000 barrels per day in 2009.

Greater Kuparuk Area

We operate the Greater Kuparuk Area, which is made up of the Kuparuk Field and four satellite fields: Tarn, Tabasco, Meltwater and West Sak. Kuparuk is located 40 miles west of Prudhoe Bay on Alaska s North Slope. 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 60,000 barrels per day in 2010, compared with 65,000 barrels per day in 2009.

Western North Slope

On the Western North Slope we operate the Colville River Unit, which includes the Alpine Field and three satellite fields: Nanuq, Fiord and Qannik. Alpine is located 34 miles west of Kuparuk. Our ownership interest in the area is 78 percent. Net production in 2010 was 59,000 barrels of oil per day, compared with 68,000 barrels per day in 2009. 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, was postponed due to the denial of a key permit from the U.S. Army Corps of Engineers in February 2010. We appealed their decision, and in December 2010, a ruling on our appeal remanded the matter back to the agency s district office in Alaska for further review.

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 2010 from the Cook Inlet Area averaged 73 million cubic feet per day of natural gas, compared with 85 million cubic feet per day in 2009. Production from the North Cook Inlet Unit is used primarily to supply our share of natural 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 17 net billion cubic feet of LNG in 2010, compared with 21 billion cubic feet in 2009. On February 9, 2011, we announced that due to market conditions we will cease LNG exports from the Kenai LNG Plant, effective in the second quarter of 2011, and will begin mothballing the facility for potential future use.

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. Due to continued pending litigation and associated injunctions, our plans for drilling an exploration well on our Chukchi Sea leases remain under review.

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 deepwater Gulf of Mexico (GOM). In late 2010, we entered into an agreement to farm-down an additional 10 percent of our working interest in the same Chukchi

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Sea leases, and that agreement is subject to regulatory approval. In addition, we participated in two appraisal wells in the Point Thomson Unit, where development options are currently being evaluated.

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 natural gas from Alaska s North Slope to North American markets. Denali conducted an open season during 2010, a process in which the pipeline company solicits 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. Both projects are currently evaluating bids received from potential customers during their respective open seasons and are engaged in confidential negotiations with those bidders.

U.S. Lower 48

Gulf of Mexico

At year-end 2010, our portfolio of producing properties in the GOM 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, sub-salt 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 GOM properties averaged 18,000 barrels per day of liquids and 20 million cubic feet per day of natural gas in 2010, compared with 21,000 barrels per day and 28 million cubic feet per day in 2009.

Onshore

Our 2010 onshore production principally consisted of natural gas and associated liquids production, with the majority of production located in the San Juan Basin, Permian Basin, Lobo Trend, Bossier Trend, Fort Worth Basin, panhandles of Texas and Oklahoma and Williston Basin. We also have operations in the Wind River and Anadarko Basins, as well as in East Texas and northern and southern Louisiana.

Onshore activities in 2010 were centered mostly on continued optimization and development of existing assets, with particular focus on areas with higher liquids production. Total net production from all Lower 48 onshore fields in 2010 averaged 1,675 million cubic feet per day of natural gas and 142,000 barrels per day of liquids, compared with 1,899 million cubic feet per day and 145,000 barrels per day in 2009.

Shale Plays

Exploration and development continues in our shale positions in Eagle Ford, Bakken and Barnett, which produced approximately 36,000 barrels of oil equivalent per day in 2010. We plan to drill approximately 150 exploration and development wells in the Eagle Ford in 2011 and, with subsequent investments, expect to achieve peak production in 2013 and long-term average production of 65,000 to 70,000 barrels per day. We acquired approximately 90,000 additional acres in various resource plays across the Lower 48 during 2010, further expanding our significant acreage position in Lower 48 shale plays.

San Juan

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 799 million cubic feet per day of natural gas and 50,000 barrels per day of liquids in 2010, compared with 903 million cubic feet per day and 49,000 barrels per day in 2009.

Exploration

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 deepwater GOM. We were also the successful bidder on 10 blocks in the March 2010 federal offshore lease sale. At year end, we had interests in 274 lease blocks totaling 1.1 million net acres offshore GOM.

In May 2010, in response to the Deepwater Horizon incident in the GOM, the DOI issued a six-month drilling moratorium on new deepwater wells in the OCS, which was scheduled to expire on November 30, 2010. On October 12, 2010, the DOI lifted the ban, citing new regulatory requirements which would reduce the risks associated with deepwater drilling. The new rules are aimed at improving safety and environmental standards and include strengthened requirements on safety equipment, well control systems, blowout prevention practices and emergency response on offshore oil and gas operations.

The new regulations have created delays in the permitting process and deepwater exploratory drilling in the GOM. As a result, we have been unable to drill any GOM prospects or appraise the Tiber and Shenandoah discoveries, which occurred in 2009. Although there are no material impacts to our near-term production, the future effects of this incident, including any new or additional regulations that may be adopted in response, are not clearly known at this time. We will continue to evaluate the impact on our exploration prospects in the GOM.

Onshore, we actively pursued the appraisal of our existing shale plays in Eagle Ford in South Texas, the Bakken in the Williston Basin and the Barnett in the Fort Worth Basin. We have seen encouraging results in these liquids-rich plays and plan to continue appraisal and development in 2011.

Transportation

We own a 25 percent interest in the Rockies Express Pipeline (REX). REX is a 1,679-mile natural gas pipeline stretching from northwestern Colorado to eastern Ohio, which became fully operational in November 2009. REX has the capacity to deliver 1.8 billion cubic feet of natural gas per day to eastern markets.

E&P EUROPE

In 2010, E&P operations in Europe contributed 21 percent of E&P s worldwide liquids production, compared with 23 percent in 2009. European operations contributed 18 percent of natural gas production in 2010 and 2009. 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 2010 from the Greater Ekofisk Area was 80,000 barrels of liquids per day and 79 million cubic feet of natural gas per day, compared with 92,000 barrels per day and 89 million cubic feet per day in 2009.

We also have varying ownership interests in eight other producing fields in the Norwegian sector of the North Sea and in the Norwegian Sea. Net production from these fields averaged 57,000 barrels of liquids per day and 130 million cubic feet of natural gas per day in 2010, compared with 68,000 barrels per day and 128 million cubic feet per day in 2009.

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Exploration

We participated in two exploration wells during 2010. Both the Megalodon and Dalsnuten wells failed to find commercial hydrocarbons and were expensed as dry holes.

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.

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 302 million cubic feet of natural gas per day and 39,000 barrels of liquids per day in 2010, compared with 304 million cubic feet per day and 40,000 barrels per day in 2009.

We operate and hold a 36.5 percent interest in the Judy/Joanne/Jasmine Fields, which together make up J-Block, located in the U.K. central North Sea. 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. The Judy/Joanne/Jade Fields produced a net 11,000 barrels of liquids per day and 82 million cubic feet of natural gas per day in 2010, compared with 12,000 barrels per day and 96 million cubic feet per day in 2009. In 2010, we received government approval for the development of the Jasmine Field, which is expected to startup in 2012, and achieve average net peak production of 35,000 barrels of oil equivalent per day by 2013.

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 2010 of 150 million cubic feet per day of natural gas, compared with 185 million cubic feet per day in 2009.

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 2010 averaged 61 million cubic feet of natural gas per day, compared with 60 million cubic feet per day in 2009.

In the Atlantic Margin, we have a 24 percent interest in the Clair Field. Net production in 2010 averaged 9,000 barrels of liquids per day, compared with 12,000 barrels per day in 2009.

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 15,000 barrels of liquids per day and 11 million cubic feet of natural gas per day in 2010, compared with 16,000 barrels per day and 12 million cubic feet per day in 2009.

Exploration

We were awarded six blocks in the U.K. 26th Licensing Round. Three are in close proximity to our producing J-Block infrastructure in the central North Sea, while one is adjacent to our Britannia Field. The remaining blocks represent growth opportunities in the Dutch Bank Basin of the North Sea.

Transportation

We have a 10 percent interest in the Interconnector Pipeline, which links the United Kingdom and Belgium and facilitates marketing natural gas produced in the United Kingdom throughout Europe. We have export capability to ship up to 220 million cubic feet of natural gas per day to markets in continental Europe via the Interconnector, and our reverse-flow rights provide 85 million cubic feet per day of 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.

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Poland

Exploration

We are participating in 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 drilled two wells in 2010 and plan to continue appraisal of the play in 2011.

E&P CANADA

E&P operations in Canada contributed 11 percent of E&P s worldwide liquids production in 2010 and 2009. Canadian operations contributed 21 percent of E&P s worldwide natural gas production in 2010, compared with 22 percent in 2009.

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 984 million cubic feet per day of natural gas and 38,000 barrels per day of liquids in 2010, compared with 1,062 million cubic feet per day and 40,000 barrels per day in 2009. Our 2010 drilling program focused on the development and exploitation of several liquids-rich resource opportunities, which included the Cardium Formation that lies primarily on our existing land base within the Deep Basin and central Alberta. We initiated temporary production curtailments of approximately 150 million cubic feet equivalent per day from September through early December 2010, in response to continued low natural gas prices in western Canada.

Surmont

We operate and have a 50 percent interest in the Surmont oil sands lease, located approximately 35 miles south of Fort McMurray, Alberta. An enhanced thermal oil recovery method called steam-assisted gravity drainage (SAGD) is used at Surmont. The average net production of bitumen during 2010 was 10,000 barrels per day, compared with 7,000 barrels per day in 2009. Surmont Phase II construction began in 2010, with a targeted production startup in 2015. Surmont s net production is expected to increase to 50,000 barrels per day by 2017.

FCCL

We have two 50/50 North American heavy oil business ventures with Cenovus Energy Inc.: FCCL Partnership, a Canadian upstream general partnership, and WRB Refining LP, a U.S. downstream limited partnership. FCCL s assets, operated by Cenovus, include 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 49,000 barrels per day in 2010, compared with 43,000 barrels per day in 2009. In the third quarter of 2010, FCCL received regulatory approval for Phases F, G and H at Foster Creek. Construction of Christina Lake Phase C continued in 2010, with first production expected in the second half of 2011. Construction of Christina Lake Phase D also continued through 2010. See the Refining and Marketing (R&M) section for information on WRB.

Syncrude Canada Ltd.

We sold our 9.03 percent interest in the Syncrude Canada Ltd. joint venture in June 2010 for $4.6 billion. Syncrude had synthetic oil proved reserves of 248 million barrels at December 31, 2009. Production averaged 12,000 barrels per day in 2010, compared with 23,000 barrels per day in 2009.

Parsons Lake/Mackenzie Gas Project

We are involved 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 project is in the final stage of regulatory approval, anticipated in early 2011; however, detailed engineering work continues to be deferred pending resolution with the Canadian government on the fiscal and commercial framework.

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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 2010, we completed drilling an exploration well in the Laurentian Basin, located offshore eastern Canada, which did not find commercial quantities of hydrocarbons and was expensed as a dry hole. In western Canada, we participated in 28 wells resulting in 20 discoveries.

E&P SOUTH AMERICA

Venezuela

In 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. As a result, Venezuela s national oil company, Petróleos de Venezuela S.A. (PDVSA), or its affiliates, directly assumed control over ConocoPhillips interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project. In response to this expropriation, we filed a request for international arbitration on November 2, 2007, with the World Bank s International Centre for Settlement of Investment Disputes (ICSID). An arbitration hearing was held during 2010 before ICSID. We are awaiting their decision.

Ecuador

In 2008, Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, initiated arbitration before 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 ICSID, Ecuador confiscated the crude oil production of Burlington and its co-venturer and sold the illegally seized crude oil. In 2009, Ecuador took over operations in Blocks 7 and 21, fully expropriating our assets. In June 2010, the ICSID tribunal concluded it has jurisdiction to hear the expropriation claim. A hearing on case merits is scheduled for March 2011. For additional information, see Note 10 Impairments, in the Notes to Consolidated Financial Statements.

Exploration

In November 2010, Burlington Resources, Inc., and PetroEcuador signed termination agreements for exploration Blocks 23 and 24, ending our participation in both blocks.

Peru

Exploration

During 2010, we executed two farm-downs that reduced our interests in Blocks 123, 124 and 129, which are awaiting final government approval. We are currently completing the initial 2D seismic program for Blocks 123 and 129 and plan to analyze the results in 2011. We also own a 35 percent working interest in Block 39.

E&P ASIA PACIFIC/MIDDLE EAST

In 2010, E&P operations in the Asia Pacific/Middle East Region contributed 15 percent of E&P s worldwide liquids production and 19 percent of natural gas production, compared with 13 percent and 16 percent in 2009, respectively.

Australia and Timor Sea

Australia Pacific LNG

Australia Pacific LNG (APLNG), our 50/50 joint venture with Origin Energy, is focused on producing CBM from the Bowen and Surat Basins in Queensland, Australia. Gas is currently sold to domestic customers, while progress continues on the development of an LNG processing and export sales business. Once established, this will enhance our LNG position and serve as an additional LNG hub targeting Asia Pacific markets. Two initial 4.2-million-tons-per-year LNG trains are anticipated, with over 10,000 gross wells ultimately envisioned to supply both the domestic gas market and the LNG development. The additional wells will be supported by expanded gas gathering systems, centralized gas processing and compression stations, and water treatment facilities, in addition to a new export pipeline from the gas fields to the LNG facilities.

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Our share of the joint venture s production in 2010 was 115 million cubic feet per day of natural gas, compared with 84 million cubic feet per day in 2009. CBM field development work is ongoing in parallel with front-end engineering associated with the planned LNG processing facilities. Engagement with potential LNG buyers continues to progress, and a final investment decision on the initial phase of the project is planned for mid-2011.

In November 2010, the APLNG LNG development project received environmental approval from Australia s Queensland state. In late February 2011, the project received environmental approval from the Australian federal government.

Bayu-Undan

We operate and hold a 57.2 percent ownership interest in the Bayu-Undan Field located in the Timor Sea. Net production from the field averaged 31,000 barrels of liquids per day in 2010, compared with 35,000 barrels per day in 2009. Our share of natural gas production was 198 million cubic feet per day in 2010, compared with 216 million cubic feet per day in 2009. Produced natural gas is used to supply the Darwin LNG Plant, in which we own a 57.2 percent interest. In 2010, we sold 147 billion gross cubic feet of LNG to utility customers in Japan, compared with 156 billion cubic feet in 2009.

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 must be resolved before significant funding commitments can be made. These include gaining both governments approval of the development concept selected by the co-venturers and establishing fiscal stability arrangements.

Western Australia

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 in both 2010 and 2009.

Exploration

We operate and own a 60 percent interest in three permits located in the Browse Basin, offshore northwest Australia. During 2010, we continued the exploration and appraisal programs and drilled two wells, Poseidon-2 and Kronos-1, both of which encountered hydrocarbons. We intend to carry out a second phase of drilling in the Browse Basin during 2011 and 2012. Analysis of the recently acquired seismic survey over the discovered resource area is ongoing.

Qatar

Qatargas 3 (QG3) 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 over a 25 year life. The project also includes a 7.8-million-gross-ton-per-year LNG facility, from which LNG is shipped in leased LNG carriers destined for sale in the United States and other markets. First production was achieved in October 2010, with eight LNG cargoes loaded and shipped in 2010.

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. Definitive terminal and pipeline use agreements have been reached, which will provide us with terminal and pipeline capacity for the receipt, storage and regasification of the LNG purchased from QG3 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 averaged 463 million cubic feet per day of natural gas and 17,000 barrels per day of liquids in 2010, compared with 447 million cubic feet per day and 19,000 barrels per day in 2009. Our producing assets are primarily concentrated in two core areas: South Natuna Sea and onshore South Sumatra.

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South Natuna Sea Block B

The offshore South Natuna Sea Block B PSC, in which we have a 40 percent interest, 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.

South Sumatra

These onshore blocks consist 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. Unitization of the Suban natural gas field commenced in 2010, reflecting that approximately 8 percent of the field s proved reserves are now attributable to an adjacent PSC. The unitization is expected to be finalized during 2011. 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, with interests ranging from 60 to 100 percent. We began exploration drilling in the fourth quarter of 2010. The first well drilled on these offshore PSCs was the Aru-1. We did not find recoverable resources with the well, and it was expensed as a dry hole in the fourth quarter of 2010. We also operate and own an 80 percent interest in 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 is used to accommodate production from these fields. Net production averaged 56,000 barrels of oil per day in 2010, compared with 33,000 barrels per day in 2009. Production from the Peng Lai area is expected to increase due to continued development of Peng Lai 19-3, with annual average net production of 60,000 barrels of oil per day anticipated in 2011.

The Xijiang development consisted 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 1,000 barrels per day in 2010, compared with 5,000 barrels per day in 2009. 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 ended in November 2010. Our ownership in these fields was 24.5 percent and 12.3 percent, respectively.

We have a 24.5 percent interest in the offshore Panyu development, also located in the South China Sea, which produced 11,000 net barrels of oil per day in both 2010 and 2009. We plan to expand the scope and capacity of the existing two fields and anticipate government approval of the expansion in the first half of 2011.

Exploration

In 2009, we entered a pilot evaluation program in a CBM play in the onshore Qinshui Basin. The pilot program was expected to last between 12-18 months and involved drilling and monitoring the production performance of a series of horizontal wells. In the fourth quarter of 2010, we terminated our involvement in this program.

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, and our activities are focused around three producing fields: Su Tu Den, Su Tu Den Northeast and Su Tu Vang; and two fields in development: Su Tu Trang and Su Tu Nau. First production on the Su Tu Den Northeast Field occurred in May 2010, averaging a net 4,000 barrels of oil per day and 4 million cubic feet per day of natural gas. Net production from the three producing fields averaged 18,000 barrels of oil per day in 2010, compared with 22,000 barrels per day in 2009.

We have a 36 percent interest in the Rang Dong Field in Block 15-2. Net production in 2010 was 6,000 barrels per day of liquids and 12 million cubic feet per day of natural gas, compared with 7,000 barrels per day and 15 million cubic feet per day in 2009.

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 own interests in three deepwater PSCs located off the eastern Malaysian state of Sabah: Block G, Block J, and the Kebabangan Cluster. We have a 35 percent interest in Block G, 40 percent in Block J, and 30 percent in the Kebabangan Cluster. Development of the Gumusut deepwater oil discovery in Block J continues and includes the installation of a semi-submersible oil production platform. First production for Gumusut is anticipated in 2013, with estimated net peak production of 29,000 barrels of liquids per day occurring in 2014.

Exploration

During 2010, we participated in the Ubah-4 appraisal well in Block G. The well was suspended in order to evaluate development options for the area.

Bangladesh

Exploration

We were formally awarded two deepwater blocks offshore Bangladesh in 2009. PSC negotiations are currently underway with government authorities.

Abu Dhabi

In April 2010, we decided to end participation in development of the Shah Gas Field in Abu Dhabi, United Arab Emirates.

E&P AFRICA

During 2010, E&P operations in Africa contributed 8 percent of E&P s worldwide liquids production and 3 percent of natural gas production, compared with 7 percent and 2 percent, respectively, in 2009.

Nigeria

We have a 20 percent nonoperating interest in four onshore Oil Mining Leases (OMLs). In 2010, net production from these leases was 20,000 barrels of liquids per day and 141 million cubic feet of natural gas per day, compared with 19,000 barrels per day and 111 million cubic feet per day in 2009.

Natural gas is sourced from our proved reserves in the OMLs and provides fuel for a 480-megawatt gas-fired power plant in Kwale, Nigeria. We have a 20 percent interest in this power plant, which supplies electricity to Nigeria s national electricity supplier. In 2010, the plant consumed 5 million net cubic feet per day of natural gas.

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

Exploration

We drilled one exploration well during 2010, the Tuomo C. The well found commercial hydrocarbons and is being incorporated into the ongoing Tuomo/Tuomo West Field development.

Libya

We hold a 16.3 percent interest in the Waha concessions in Libya, which encompass nearly 13 million gross acres. Net oil production averaged 46,000 barrels per day in 2010, versus 45,000 barrels per day in 2009.

Algeria

Our activities in Algeria are centered around three fields in Block 405a: the Menzel Lejmat North Field (MLN), the Ourhoud Field, and the EMK Field. We operate and have a 65 percent interest in MLN, and we have a 3.7 percent interest in Ourhoud and a 16.9 percent interest in EMK. The El Merk Project was sanctioned in 2009 to develop the EMK Field, and engineering, procurement and construction is ongoing. Net production from MLN and Ourhoud averaged 13,000 barrels of oil per day in 2010, compared with 14,000 barrels per day in 2009.

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 achieved initial production of the Yuzhno Khylchuyu (YK) Field in June 2008, and development was completed in 2010. Net production averaged 45,000 barrels per day in 2010, compared with 46,000 barrels per day in 2009. 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 7,000 barrels of oil per day in 2010, compared with 9,000 barrels per day in 2009.

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 lasts until 2041, with options to extend the agreement an additional 20 years. A joint operating company, North Caspian Operating Company, oversees the Kashagan development, and expects first production in late 2012.

Transportation

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

Exploration

We have a 24.5 percent interest in the N Block, located offshore Kazakhstan. In the fourth quarter of 2010, drilling operations were completed on the Rak More well. The well encountered oil and gas but requires further evaluation to determine commerciality. Further exploration drilling is planned in 2011 to determine development potential of a second area of interest within the block. 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

Greenland

Exploration

We were formally awarded a license in 2010 for oil and gas exploration in Baffin Bay, offshore Greenland. We will serve as operator, with a 61.3 percent interest in the Qamut Block. Planned activities in 2011 include field work, environmental assessments, and seismic data acquisition and evaluation.

Marine Well Containment Company

During 2010, we formed a non-profit organization with Exxon Mobil Corporation, Chevron Corporation and Royal Dutch Shell plc to develop a new oil spill containment system and improve industry spill response in the GOM. The

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Marine Well Containment Company plans to build and deploy a rapid response system that will be available to capture and contain oil in the event of a potential future underwater well blowout in the deepwater GOM.

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. Market conditions currently favor the flow of LNG to European and Asian markets; therefore, 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.

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, 2010. No difference exists between our estimated total proved reserves for year-end 2009 and year-end 2008, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2010.

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, including approximately 700 billion cubic feet related to the noncontrolling interests of consolidated subsidiaries, and 120 million barrels of crude oil in the future. These contracts have various expiration dates through the year 2029. 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, 2010, our Midstream segment represented 2 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 such as ethane, butane and propane and marketed as chemical feedstock, fuel or blendstock. Total natural gas liquids extracted in 2010, including our share of DCP Midstream, were 193,000 barrels per day, compared with 187,000 barrels per day in 2009.

DCP Midstream markets a portion of its natural gas liquids to us and CPChem under a supply agreement whose volume commitments remain steady until December 31, 2014. 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, 2010, DCP Midstream owned or operated 55 natural gas liquids extraction and 10 natural gas liquids fractionation plants, and its gathering and

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transmission systems included approximately 61,000 miles of pipeline. In 2010, DCP Midstream s raw natural gas throughput averaged 6.1 billion cubic feet per day, and natural gas liquids extraction averaged 369,000 barrels per day, compared with 6.1 billion cubic feet per day and 358,000 barrels per day in 2009. 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 includes the following:

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. Our net share of capacity is 24,300 barrels per day. In October 2010, Gulf Coast Fractionators announced plans to expand the capacity of its fractionation facility to 145,000 barrels per day. The expansion is expected to be operational in the second quarter of 2012.

A 40 percent interest in a fractionation plant in Conway, Kansas. Our net share of capacity is 43,200 barrels per day.

A 12.5 percent equity interest in a fractionation plant in Mont Belvieu, Texas. Our net share of capacity is 26,000 barrels per day.

Marketing operations that optimize 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 throughout the Atlantic Basin. Its facilities include a 2-billion-cubic-feet-per-day gas processing plant and a 70,000-barrel-per-day natural gas liquids fractionator. Our share of natural gas liquids extracted averaged 9,000 barrels per day in 2010, compared with 8,000 barrels per day in 2009. Our share of fractionated liquids averaged 18,000 barrels per day in 2010, compared with 17,000 barrels per day in 2009.

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REFINING AND MARKETING (R&M)

At December 31, 2010, our R&M segment represented 24 percent of ConocoPhillips total assets. Our R&M segment primarily refines crude oil and other feedstocks into petroleum products (such as gasolines, distillates and aviation fuels); buys, sells and transports crude oil; and buys, transports, distributes and markets petroleum products. R&M has operations in the United States, Europe and Asia. 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.

R&M UNITED STATES

Refining

At December 31, 2010, 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

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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, at 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	59	59	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. MSLP processes our long residue, which is produced from heavy sour crude oil, for a processing fee. Fuel-grade petroleum coke is produced as a by-product and becomes the property of MSLP. 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. PDVSA has initiated arbitration with the International Chamber of Commerce challenging our actions, and this arbitration is underway. We continue to use the equity method of accounting for our investment in MSLP.

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WRB

We have two 50/50 North American heavy oil business ventures with Cenovus Energy Inc.: FCCL Partnership, a Canadian upstream general partnership, and WRB Refining LP, a U.S. downstream limited partnership. 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.

WRB s processing capability of heavy Canadian crude is currently 145,000 barrels per day. We continue to progress the coker and refinery expansion (CORE) project at the Wood River Refinery, with operational startup anticipated in the fourth quarter of 2011. Upon completion of the CORE Project, total processing capability of heavy Canadian or similar crudes within WRB will increase to 275,000 barrels per day. The majority of the existing asphalt production at Wood River will be replaced with production of upgraded products.

Excel Paralubes

We own a 50 percent interest in the Excel Paralubes joint venture, which 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.

Marketing

In the United States, as of December 31, 2010, we marketed gasoline, diesel and aviation fuel through approximately 8,300 marketer-owned outlets in 49 states. The majority of these sites utilize the *Phillips 66*, *Conoco* or *76* brands.

Wholesale

At December 31, 2010, our wholesale operations utilized a network of marketers operating approximately 7,150 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. In addition, we held brand-licensing agreements with approximately 400 sites. 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, 2010, aviation gasoline and jet fuel were sold through independent marketers at approximately 750 *Phillips 66*-branded locations in the United States.

Retail

In June 2010, we sold our interest in CFJ Properties, a joint venture which owned and operated 110 *Flying J*-branded truck travel plazas.

In December 2006, we announced plans to divest approximately 830 of our U.S. company-owned outlets. This program was completed during 2010.

Lubricants

We manufacture and sell automotive, commercial and industrial lubricants which are marketed under the *Phillips 66, Conoco, 76* and *Kendall* brands, as well as other private label brands.

Transportation

We distribute refined products to our customers via company-owned and common-carrier pipelines, barges, railcars and trucks.

Pipelines and Terminals

At December 31, 2010, R&M managed approximately 24,000 miles of common-carrier crude oil, raw natural gas liquids, natural gas and petroleum products pipeline systems in the United States, including those partially owned or operated by affiliates. In addition, we owned or operated 44 finished product terminals, 7 liquefied petroleum gas terminals, 5 crude oil terminals and 1 coke exporting facility.

Tankers

At December 31, 2010, we had 19 double-hulled crude oil tankers under charter, with capacities ranging in size from 713,000 to 2,100,000 barrels. These tankers are primarily used to transport feedstocks to certain of our U.S. refineries. In addition, we utilized four double-hulled product tankers, with capacities ranging from 315,000 to 332,000 barrels, 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 Exploration and Production (E&P) section, 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, polypropylene, pipeline flow improvers and anode material for high-power lithium-ion batteries. 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.

R&M INTERNATIONAL

Refining

At December 31, 2010, R&M owned or had an interest in five refineries outside the United States.

			Net Crude Throughput Capacity (MBD)	
			At December 31,	Effective January 1,
Refinery	Location	Ownership	2010	2011
Humber	N. Lincolnshire, United Kingdom	100.00%	221	221
Whitegate	Cork, Ireland	100.00	71	71
Wilhelmshaven	Wilhelmshaven, Germany	100.00	260	-
MiRO*	Karlsruhe, Germany	18.75	58	58
Melaka	Melaka, Malaysia	47.00	61	76
			671	426

**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	·				·	·
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.*

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Capacities for and yields of clean products, as well as other products produced, at 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	·			
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.

The project to expand the crude oil, conversion and treating unit capacity of the Melaka Refinery was completed in the fourth quarter of 2010. As a result, effective January 1, 2011, our net share of the refinery s crude throughput capacity will increase from 61,000 to 76,000 barrels per day, and clean product capacity for gasoline and distillates will increase to 17,500 and 47,000 barrels per day, respectively.

In the second quarter of 2010, due to ongoing unfavorable market conditions and consistent with our strategy of maintaining capital discipline and reducing our downstream portfolio over time, we canceled plans for a project to upgrade our refinery in Wilhelmshaven, Germany. We are currently evaluating offers to sell the facility. If sufficient value is not achievable from a sale, we plan to operate the facility as a terminal. As a result, effective January 1, 2011, we will no longer include Wilhelmshaven s capacity in our stated refining capacities or our capacity utilization metrics.

Also consistent with our strategy of reducing our downstream portfolio, in the first quarter of 2010, we ended our participation in a new refinery project in Yanbu Industrial City, Saudi Arabia.

Marketing

At December 31, 2010, 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 approach. 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, 2010, we had approximately 1,450 marketing outlets in our European operations, of which approximately 890 were company-owned and 360 were dealer-owned. We also held brand-licensing agreements with approximately 200 sites. Through our joint venture operations in Switzerland, we also have interests in 245 additional sites.

LUKOIL INVESTMENT

At year-end 2009, we had a 20 percent ownership interest in OAO LUKOIL. In July 2010, we announced our intention to sell our entire interest. During 2010, we sold approximately 151 million shares of LUKOIL, and as a result of these sales, our ownership interest was 2.25 percent at December 31, 2010, based on authorized and issued shares. By the end of the third quarter of 2010, our ownership interest declined to a level at which we were no longer able to exercise significant influence over the operating and financial policies of LUKOIL. Accordingly, at the end of the third quarter of 2010, we stopped reporting equity earnings, proved reserves and production related to our LUKOIL investment. In the first quarter of 2011, we sold our remaining interest.

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See Note 6 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for more information.

CHEMICALS

At December 31, 2010, our Chemicals segment represented 2 percent of ConocoPhillips total assets. The Chemicals segment consists of our 50 percent equity investment in CPChem, a joint venture with Chevron Corporation, headquartered in The Woodlands, Texas.

CPChem s business is structured around two primary operating segments: Olefins & Polyolefins (O&P) and Specialties, Aromatics & Styrenics (SAS). The O&P 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 SAS segment manufactures and markets aromatics products, such as benzene, styrene, paraxylene and cyclohexane, as well as polystyrene and styrene-butadiene copolymers. SAS also 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, 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. The 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, an ethylene cracker that provides ethylene feedstock via pipeline to the Q-Chem II plants was developed in Ras Laffan Industrial City, Qatar. The ethylene cracker and pipeline are owned by Ras Laffan Olefins Company, a joint venture of Q-Chem II and Qatofin Company Limited. Collectively, Q-Chem II s interest in the ethylene cracker and pipeline and the polyethylene and normal alpha olefins plants are referred to as the Q-Chem II Project. Operational startup of the Q-Chem II Project was achieved in 2010.

Saudi Chevron Phillips Company (SCP) is a 50-percent-owned joint venture of CPChem that owns and operates an aromatics complex at Jubail Industrial City, Saudi Arabia. Jubail Chevron Phillips Company, another 50-percent-owned joint venture of CPChem, owns and operates an integrated styrene facility adjacent to the SCP aromatics complex.

Saudi Polymers Company (SPCo), a 35-percent-owned joint venture company of CPChem, is constructing an integrated petrochemicals complex at Jubail Industrial City, Saudi Arabia. SPCo will produce ethylene, propylene, polyethylene, polypropylene, polystyrene and 1-hexene. Construction began in January 2008, and commercial production is scheduled to begin in late 2011.

CPChem plans to build a 1-hexene plant capable of producing in excess of 200,000 metric tons per year at its Cedar Bayou Chemical Complex in Baytown, Texas. Project planning has begun, with startup anticipated in 2014.

EMERGING BUSINESSES

At December 31, 2010, 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, refining, alternative energy, biofuels and the environment.

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Power Generation

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, the following projects have a significant merchant component and are included in the Emerging Businesses segment:

The Immingham Combined Heat and Power Plant, a wholly owned 1,180-megawatt facility in the United Kingdom, which provides steam and electricity to the Humber Refinery and steam to a neighboring refinery, as well as merchant power into the U.K. market.

Sweeny Cogeneration LP, our 50 percent joint venture near the Sweeny Refinery complex.

In December 2010, we sold a gas-fired cogeneration plant located in Orange, Texas.

Technology Development

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 are progressing the technology development of second-generation biofuels with Iowa State University, the Colorado Center for Biorefining and Biofuels and Archer Daniels Midland. We have also established a relationship with the University of Texas Energy Institute to collaborate on emerging technologies. Internally, we are continuing to evaluate wind, solar and geothermal investment opportunities.

In early 2011, we announced we will partner with General Electric Capital and NRG Energy, Inc., to form a new joint venture, Energy Technology Ventures (ETV), which will focus on development of next generation energy technology. ETV will invest in, and offer commercial collaboration opportunities to, venture- and growth-stage energy technology companies in the renewable power generation, smart grid, energy efficiency, oil, natural gas, coal and nuclear energy, emission controls and biofuels sectors.

In addition, we are equal co-venturers with General Electric Company in a Global Water Sustainability Center in Qatar, which researches and develops water solutions for the petroleum, petrochemical, municipal and agricultural sectors.

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 have also licensed E-Gas to third parties in Asia and North America, and are pursuing several additional licensing opportunities.

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.

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 2009 reserves statistics, we had the sixth-largest total of worldwide proved reserves of nongovernment-controlled companies. We deliver our production into the worldwide 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.

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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 extractor 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.

Our R&M segment competes primarily in the United States, Europe and Asia. Based on the statistics published in the December 6, 2010, 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 2010 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 2010, we held a total of 1,398 active patents in 62 countries worldwide, including 597 active U.S. patents. During 2010, we received 34 patents in the United States and 69 foreign patents. Our products and processes generated licensing revenues of $90 million in 2010. 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 $230 million, $190 million and $209 million in 2010, 2009 and 2008, 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 57 through 60 under the captions Environmental and Climate Change is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2010 and those expected for 2011 and 2012.

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*.

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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, bitumen, natural gas, natural gas liquids, LNG and refined products. The factors influencing these prices are beyond our control. Lower crude oil, bitumen, natural gas, natural gas liquids, LNG 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, bitumen and natural gas production will decline, resulting in an adverse impact to our business.

The rate of production from upstream fields 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, bitumen and natural gas reserves could impair the quantity and value of those reserves.

Our proved reserve information included in this annual report has been derived from engineering estimates prepared or reviewed by our personnel. Any significant future price changes could 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, bitumen 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.
- Exploration and production activities in environmentally sensitive areas, such as offshore environments, arctic fields, oil sands reservoirs and shale gas plays.

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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.

Although 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.

In addition, in response to the Deepwater Horizon incident, the United States, as well as other countries where we do business, may make changes to their laws or regulations governing offshore operations that could have a material adverse effect on our business.

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 was derived from production outside the United States in both 2009 and 2010, and 56 percent of our proved reserves, as of December 31, 2010, 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, bitumen, 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, bitumen 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, bitumen 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 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 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.

We do not insure against all potential losses; and therefore, we could be harmed by unexpected liabilities and increased costs.

We maintain insurance against many, but not all, potential losses or liabilities arising from operating risks. As such, our insurance coverage may not be sufficient to fully cover us against potential losses arising from such risks. Uninsured losses and liabilities arising from operating risks could reduce the funds available to us for capital, exploration and investment spending and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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 exploration, production, 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 2010, as well as matters previously reported in our 2009 Form 10-K and our first-, second- and third-quarter 2010 Form 10-Qs that were not resolved prior to the fourth quarter of 2010. 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 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

There are no new matters to report.

Matters Previously Reported

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 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.

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ConocoPhillips has reached an agreement with the EPA and DOJ regarding an appropriate penalty amount, which will be reflected in the third amendment to the consent decree in Civil Action No. H-05-258 (the agreed-upon penalty amount remains confidential until that time).

On May 19, 2010, the Lake Charles Louisiana Refinery received a Consolidated Compliance Order and Notice of Potential Penalty from the Louisiana Department of Environmental Quality (LDEQ) alleging various violations of applicable air emission regulations, as well as certain provisions of the consent decree in Civil Action No. H-01-4430. ConocoPhillips will work with the LDEQ to resolve this matter.

On September 23, 2010, the Los Angeles County Fire Department Health and Hazardous Materials Division (HHMD) issued a proposed penalty of $127,000 to ConocoPhillips. The penalty pertains to alleged violations of hazardous waste regulations at the Los Angeles Refinery noted by HHMD during its refinery compliance inspections in November and December 2009. ConocoPhillips resolved this matter with a settlement payment of $102,880 to HHMD.

On January 22, 2010, the Bay Area Air Quality Management District (BAAQMD) issued a penalty demand to resolve 16 Notices of Violation issued in 2008 and 2009 that allege violations of air pollution control regulations and/or facility permit conditions at the Rodeo facility in San Francisco, California. ConocoPhillips resolved this matter with a settlement payment of $125,050 to BAAQMD.

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 continue to contest this lawsuit.

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EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Position Held	Age*
John A. Carrig	President	59
Willie C. W. Chiang	Senior Vice President, Refining, Marketing, Transportation and Commercial	50
Greg C. Garland	Senior Vice President, Exploration and Production Americas	53
Alan J. Hirshberg	Senior Vice President, Planning and Strategy	49
Janet L. Kelly	Senior Vice President, Legal, General Counsel and Corporate Secretary	53
Ryan M. Lance	Senior Vice President, Exploration and Production International	48
James J. Mulva	Chairman of the Board of Directors and Chief Executive Officer	64
Glenda M. Schwarz	Vice President and Controller	45
Jeff W. Sheets	Senior Vice President, Finance and Chief Financial Officer	53

**On February 15, 2011.*

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 the 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 11, 2011.

Set forth below is information about the executive officers.

John A. Carrig has served as President since October 2010, having previously served as President and Chief Operating Officer from 2008 to October 2010. Prior to that, he served as Executive Vice President, Finance and Chief Financial Officer since the merger of Conoco and Phillips in 2002 (the merger).

Willie C. W. Chiang was appointed Senior Vice President, Refining, Marketing, Transportation and Commercial in October 2010. He previously served as Senior Vice President, Refining, Marketing and Transportation from 2008 to October 2010; Senior Vice President, Commercial from 2007 to 2008; and President, Americas Supply & Trading, Commercial, from 2005 through 2007.

Greg C. Garland was appointed Senior Vice President, Exploration and Production Americas in October 2010, having previously served as President and Chief Executive Officer of CPChem since 2008. Prior to that, he served as Senior Vice President, Planning and Specialty Products at CPChem from 2000 to 2008.

Alan J. Hirshberg was appointed Senior Vice President, Planning and Strategy in October 2010. Prior to that, he was employed by Exxon Mobil Corporation and served as Vice President, Worldwide Deepwater and Africa Projects since 2009; Vice President, Worldwide Deepwater Projects from 2008 to 2009; Vice President, Established Areas Projects from 2006 to 2008; and Vice President, Operated by Others Projects in 2006.

Janet L. Kelly was appointed Senior Vice President, Legal, General Counsel and Corporate Secretary in 2007, having previously served as Deputy General Counsel since 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; President, Exploration and Production Europe, Asia, Africa and the Middle East from 2007 to 2009; Senior Vice President, Technology in 2007; and Senior Vice President, Technology and Major Projects since 2006.

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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 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 2009. She previously served as General Auditor and Chief Ethics Officer from 2008 to 2009, having previously served as General Manager, Downstream Finance and Performance Analysis since 2005.

Jeff W. Sheets was appointed Senior Vice President, Finance and Chief Financial Officer in October 2010. Prior to that, he served as Senior Vice President, Planning and Strategy since 2008, having previously served as Vice President and Treasurer since the merger.

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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
2010				
First	$	**53.80**	**46.63**	**.50**
Second		**60.53**	**48.51**	**.55**
Third		**58.03**	**48.06**	**.55**
Fourth		**68.58**	**56.80**	**.55**
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

Closing Stock Price at December 31, 2010	$	68.10
Closing Stock Price at January 31, 2011	$	71.46
Number of Stockholders of Record at January 31, 2011*		58,644

**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

Period	Total Number of Shares Purchased*		Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**		Millions of Dollars Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
October 1-31, 2010	17,776,116	$	59.62	17,540,398	$	2,696
November 1-30, 2010	11,464,464		60.93	11,458,408		1,998
December 1-31, 2010	13,266,256		65.25	13,249,000		1,134
Total	42,506,836	$	61.73	42,247,806		

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

**

On March 24, 2010, we announced plans to repurchase up to $5 billion of our common stock through 2011. On February 11, 2011, we announced plans to repurchase up to $10 billion of our common stock over the subsequent two years. Acquisitions for the share repurchase program are made at management s discretion, at prevailing prices, subject to market conditions and other factors. Repurchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock repurchased under the plan are held as treasury shares.

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Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2010	2009*	2008*	2007*	2006*
Sales and other operating revenues	**$ 189,441**	149,341	240,842	187,437	183,650
Net income (loss)	**11,417**	4,492	(16,279)	11,545	15,410
Net income (loss) attributable to ConocoPhillips	**11,358**	4,414	(16,349)	11,458	15,334
Per common share					
Basic	**7.68**	2.96	(10.73)	7.06	9.67
Diluted	**7.62**	2.94	(10.73)	6.96	9.53
Total assets	**156,314**	152,138	142,865	177,094	164,557
Long-term debt	**22,656**	26,925	27,085	20,289	23,091
Joint venture acquisition obligation long-term	**4,314**	5,009	5,669	6,294	-
Cash dividends declared per common share	**2.15**	1.91	1.88	1.64	1.44

**Recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information.*

Many factors can impact the comparability of this information, such as:

The financial data for 2010 includes the impact of $5,803 million before-tax ($4,583 million after-tax) related to gains on asset dispositions and LUKOIL share sales.

The financial data for 2008 includes the impact of impairments related to goodwill and to our LUKOIL investment that together amount to $32,939 million before- and after-tax.

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.

See Management s Discussion and Analysis of Financial Condition and Results of Operations and the Notes to Consolidated Financial Statements for a discussion of factors that will enhance an understanding of this data.

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

February 23, 2011

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 anticipate, estimate, believe, budget, continue, could, intend, may, plan, potential, predict, seek, should, will, would, ex forecast, goal, guidance, outlook, effort, target and similar expressions identify forward-looking statements. 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 65.

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 29,700 employees worldwide, and at year-end 2010 had assets of $156 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, bitumen, natural gas, liquefied natural gas (LNG) and natural gas liquids 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 investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. At December 31, 2010, our ownership interest was 2.25 percent based on issued shares. See Note 6 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for information on sales of LUKOIL shares.

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.

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In 2010, as the global economy continued to recover from the recession, the business environment for certain parts of the energy industry also recovered. Oil prices continued to increase in 2010, reflecting strong oil demand growth, especially in China, and an improved economic outlook for the United States. U.S. natural gas prices, however, remained under pressure during 2010, despite a colder-than-normal winter and hotter-than-normal summer. U.S. natural gas production continues to increase at a faster rate than the demand recovery from the economic crisis, primarily as a result of increased production from shale plays. Storage levels are below 2009 levels, but remain historically high. We expect these factors will continue to moderate natural gas prices, resulting in limited U.S. LNG imports in the near- to mid-term, and potentially impacting the timing of commercialization of our Alaska North Slope and Canadian Arctic gas resources.

In late 2009, we announced several strategic initiatives designed to improve our financial position and increase returns on capital. We announced plans to raise $10 billion from asset dispositions through the end of 2011, reduce our debt and increase shareholder distributions. As of year-end 2010, we have generated approximately $7 billion from asset dispositions, the proceeds of which were primarily targeted toward debt reduction. This accelerated the return to our target debt-to-capital ratio of 20 to 25 percent. In addition, we increased the amount of our quarterly dividend rate by 10 percent, and we paid dividends on our common stock of $3.2 billion for the full year. We also announced plans to sell our entire interest in LUKOIL, and our Board of Directors authorized the purchase of up to $5 billion of our common stock through 2011. As of year-end 2010, we had sold approximately 90 percent of our interest in LUKOIL, which generated cash proceeds of approximately $8 billion, while we repurchased approximately $4 billion of our common stock. In February 2011, our Board authorized the additional purchase of up to $10 billion of our common stock over the next two years.

Our total capital program in 2011 is expected to be $13.5 billion, a $2.8 billion increase from $10.7 billion in 2010. We also expect 2011 production to be approximately 1.7 million barrels of oil equivalent per day, excluding the impact of any additional asset sales.

Crude oil, bitumen, natural gas and LNG 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. These prices and margins can be 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 2010, our worldwide refining capacity utilization rate was 81 percent, compared with 84 percent in 2009. The lower rate primarily reflects run reductions at Wilhelmshaven in response to market conditions, partially offset by lower turnaround activity. Excluding Wilhelmshaven, the worldwide refining capacity utilization rate was 90 percent in 2010, compared with 88 percent in 2009.
>
> There has been heightened public focus on the safety of the oil and gas industry, as a result of the Deepwater Horizon incident in the Gulf of Mexico (GOM), which occurred in April 2010. Safety and environmental stewardship, including the operating integrity of our assets, remain our highest priorities. Therefore, in order to improve industry spill response, in 2010 we formed a non-profit organization, the Marine Well Containment Company LLC (MWCC), with Exxon Mobil Corporation, Chevron Corporation and Royal Dutch Shell plc to develop a new oil spill containment system. MWCC plans to build and deploy a rapid response system that will be available to capture and contain oil in the event of a potential future underwater well blowout in the deepwater GOM.

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Adding to our proved reserve base. We primarily add to our proved reserve base in three ways:

- o Successful exploration and development of new fields.
- o Acquisition of existing fields.
- o 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 ended December 31, 2010, our reserve replacement was 111 percent, excluding LUKOIL. 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, is a high priority. 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 increased by 4 percent in 2010, compared with 2009, primarily as a result of market conditions and higher transportation costs.

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, construct pipelines and LNG facilities, 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 the investment is operational and begins generating financial returns.

Our total capital program in 2010 was $10.7 billion, which included $9.8 billion of capital expenditures and investments. Our 2011 capital program is expected to be approximately $13.5 billion, which includes $12.8 billion of capital expenditures and investments. The 2011 budget is consistent with our 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.

Managing our asset portfolio. We continually evaluate our assets to determine whether they fit our strategic plans or should be sold or otherwise disposed. In 2009, we sold a majority of our U.S. retail marketing assets and announced our intention to raise $10 billion from asset dispositions through the end of 2011. In 2010, we completed the U.S. retail marketing disposition program. We also sold our 9.03 percent interest in the Syncrude oil sands mining operation; our 50 percent interest in CFJ Properties, a joint venture which owned and operated *Flying J*-branded truck and travel plazas; and several E&P properties located in the Lower 48 and western Canada. As part of a separate program, in 2010, we announced our intention to sell our entire interest in LUKOIL. As of year-end 2010, we sold approximately 90 percent of our interest in LUKOIL. We disposed of our remaining shares in the first quarter of 2011.

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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 commodity prices, production and refining capacity utilization.

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, for example, our reserve estimates are revised downward, commodity prices or refining margins decline significantly for long periods of time, or 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 which, if exploratory drilling proves unsuccessful, could lead to a material impairment of leasehold values. Before-tax impairments in 2010 totaled $2.4 billion and primarily related to the $1.5 billion property impairment of our refinery in Wilhelmshaven, Germany (WRG), and a $0.6 billion impairment of our equity investment in Naraynmarneftegaz (NMNG). 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 NMNG.

Goodwill. We had $3.6 billion of goodwill on our balance sheet at year-end 2010 and 2009. 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. 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. Our operations, primarily in E&P, can be affected by changing economic, regulatory and political environments in the various countries in which we operate, including the United States. 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. Our assets in Venezuela and Ecuador were expropriated in 2007 and 2009, respectively. In Canada, the Alberta provincial government changed the royalty structure in 2009 to tie a component of the new rate to prevailing prices. Our management carefully considers these events when evaluating projects or determining the level of activity in such countries.

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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 (WTI) were higher in 2010, compared with 2009, averaging $79.39 per barrel in 2010, an increase of 29 percent. Uncertainty about economic growth in developed countries, especially in the United States, and concerns about the debt crisis in Europe were more than offset by increased demand from China and other developing countries. Industry natural gas prices at Henry Hub increased 10 percent during 2010 to an average price of $4.39 per million British thermal units, primarily as a result of weather-related events. An increase in demand was offset by higher natural gas production levels, and as a result, natural gas storage levels remain high and have adversely impacted Henry Hub prices.
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 increased 39 percent in 2010.
Refining margins, refinery capacity utilization and cost control 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 improved during 2010, compared with 2009. The U.S. benchmark 3:2:1 crack spread increased 9 percent in 2010, while the N.W. Europe benchmark increased 16 percent. Demand for refined products improved globally in 2010, driven by the improved economic environment, particularly in the developing nations. In addition, a wider differential in prices for high-quality crude oil relative to lower-quality crude oil improved margins for 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 year-end 2009, we had a 20 percent ownership interest in LUKOIL based on authorized and issued shares. At the end of the third quarter of 2010, as a result of our plan to divest of our entire interest in LUKOIL, our ownership interest declined to a level at which we were no longer able to exercise significant influence over the operating and financial policies of LUKOIL. Accordingly, at the end of the third quarter of 2010, we stopped recording equity earnings from LUKOIL. Starting in the fourth quarter of 2010, earnings from the LUKOIL Investment segment primarily reflect the realized gain on share sales. We disposed of our remaining interest in LUKOIL in the first quarter of 2011.
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, refining, alternative energy, biofuels and the environment. Some of these technologies have the potential to become important drivers of profitability in future years.

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RESULTS OF OPERATIONS

Consolidated Results

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

		Millions of Dollars		
Years Ended December 31		**2010**	2009	2008
Exploration and Production (E&P)	$	**9,198**	3,604	(13,479)
Midstream		**306**	313	541
Refining and Marketing (R&M)		**192**	37	2,322
LUKOIL Investment*		**2,503**	1,219	(4,839)
Chemicals		**498**	248	110
Emerging Businesses		**(59)**	3	30
Corporate and Other		**(1,280)**	(1,010)	(1,034)
Net income (loss) attributable to ConocoPhillips	$	**11,358**	4,414	(16,349)

**2009 and 2008 recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information.*

2010 vs. 2009

The improved results in 2010 were primarily the result of:

Higher prices for crude oil, natural gas, natural gas liquids and liquefied natural gas (LNG) in our E&P segment. Commodity price benefits were somewhat offset by increased production taxes.

Gains of $4,583 million after-tax from asset dispositions and LUKOIL share sales.

Improved results from our domestic R&M operations, reflecting higher refining margins.

These items were partially offset by:

Impairments totaling $1,928 million after-tax.

Lower production volumes from our E&P segment.

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 $7,496 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.

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Statement of Operations Analysis

2010 vs. 2009

Sales and other operating revenues increased 27 percent in 2010, while purchased crude oil, natural gas and products increased 33 percent. These increases were primarily due to higher prices for petroleum products, crude oil, natural gas, natural gas liquids and LNG.

Equity in earnings of affiliates increased 24 percent in 2010. The increase primarily resulted from:

- Improved earnings from CPChem primarily due to higher margins in the olefins and polyolefins business line.
- Improved earnings from FCCL Partnership due to higher commodity prices and volumes.
- Improved earnings from Merey Sweeny, L.P. (MSLP) as a result of improved margins and volumes.

These increases were partially offset by a $645 million impairment of our equity investment in NMNG.

Gain on dispositions increased $5,643 million in 2010. The increase primarily reflects the $2,878 million gain realized from the June 2010 sale of our 9.03 percent interest in the Syncrude oil sands mining operation; the $1,749 million gain on the divestiture of our LUKOIL shares; gains on the disposition of certain E&P assets located in the Lower 48 and Canada; and the gain on sale of our 50 percent interest in CFJ Properties. For additional information, see Note 5 Assets Held for Sale and Note 6 Investment, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.

Impairments increased $1,245 million in 2010, primarily as a result of the second quarter impairment of WRG. For additional information, see Note 10 Impairments, in the Notes to Consolidated Financial Statements.

Taxes other than income taxes increased 8 percent during 2010, primarily due to higher production taxes as a result of higher crude oil prices and higher excise taxes on petroleum product sales.

Interest and debt expense decreased 8 percent during 2010, primarily due to lower debt levels.

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

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 49 percent in 2009, primarily due to reduced earnings from LUKOIL; DCP Midstream; MSLP; Malaysian Refining Company Sdn. Bhd.; and Excel Paralubes, which were partially offset by higher earnings from CPChem. The decreases were mainly the result of lower commodity prices and refining margins.

Gain on dispositions decreased 82 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 currency 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.

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Impairments decreased from $34,625 million in 2008 to $535 million in 2009, primarily reflecting the 2008 goodwill and LUKOIL impairments. Other impairments decreased $1,151 million during 2009. For additional information, see Note 6 Investments, Loans and Long-Term Receivables and Note 9 Goodwill and Intangibles, in the Notes to Consolidated Financial Statements.

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.

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.

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Segment Results
E&P

		2010	2009	2008
		Millions of Dollars		
Net Income (Loss) Attributable to ConocoPhillips				
Alaska	$	**1,735**	1,540	2,315
Lower 48		**1,033**	(37)	2,673
United States		**2,768**	1,503	4,988
International		**6,430**	2,101	6,976
Goodwill impairment		**-**	-	(25,443)
	$	**9,198**	3,604	(13,479)

		Dollars Per Unit		
Average Sales Prices				
Crude oil and natural gas liquids (per barrel)				
United States	$	**69.73**	53.21	89.38
International		**74.95**	57.40	89.32
Total consolidated operations		**72.63**	55.47	89.35
Equity affiliates		**74.81**	58.23	71.15
Total E&P		**72.77**	55.63	88.91
Synthetic oil (per barrel)				
International		**77.56**	62.01	103.31
Bitumen (per barrel)				
International		**51.10**	39.67	46.85
Equity affiliates		**53.43**	45.69	58.54
Total E&P		**53.06**	44.84	56.72
Natural gas (per thousand cubic feet)*				
United States		**4.27**	3.50	7.60
International		**5.60**	5.06	8.65
Total consolidated operations		**5.07**	4.40	8.20
Equity affiliates		**2.79**	2.35	2.04
Total E&P		**4.98**	4.37	8.18

**Prior periods reclassified to conform to current year presentation which includes intrasegment transfer pricing.*

Average Production Costs Per Barrel of Oil Equivalent				
United States	$	**8.30**	7.73	8.34
International		**7.96**	7.72	8.03
Total consolidated operations		**8.10**	7.73	8.17
Equity affiliates		**8.11**	7.68	13.36
Total E&P		**8.10**	7.72	8.33

Millions of Dollars

Worldwide Exploration Expenses				
General and administrative; geological and geophysical; and lease rentals	**$**	**678**	576	639
Leasehold impairment		**241**	247	273
Dry holes		**236**	359	425
	$	**1,155**	1,182	1,337

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	2010	2009	2008
	Thousands of Barrels Daily		
Operating Statistics			
Crude oil and natural gas liquids produced			
Alaska	**230**	252	261
Lower 48	**160**	166	165
United States	**390**	418	426
Canada	**38**	40	44
Europe	**211**	241	233
Asia Pacific/Middle East	**140**	132	107
Africa	**79**	78	80
Other areas	**-**	4	9
Total consolidated operations	**858**	913	899
Equity affiliates			
Russia	**52**	55	24
Asia Pacific/Middle East	**3**	-	-
	913	968	923
Synthetic oil produced			
Consolidated operations Canada	**12**	23	22
Bitumen produced			
Consolidated operations Canada	**10**	7	6
Equity affiliates Canada	**49**	43	30
	59	50	36
	Millions of Cubic Feet Daily		
Natural gas produced*			
Alaska	**82**	94	97
Lower 48	**1,695**	1,927	1,994
United States	**1,777**	2,021	2,091
Canada	**984**	1,062	1,054
Europe	**815**	876	954
Asia Pacific/Middle East	**712**	713	609
Africa	**149**	121	114
Other areas	**-**	-	14
Total consolidated operations	**4,437**	4,793	4,836
Equity affiliates			

Asia Pacific/Middle East	**169**	84	11
	4,606	4,877	4,847

**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, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2010, 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, Qatar and Russia. Total E&P production on a barrel-of-oil-equivalent (BOE) basis averaged 1,752,000 BOE per day in 2010, compared with 1,854,000 BOE per day in 2009.

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2010 vs. 2009

Earnings from our E&P segment were $9,198 million in 2010, compared with earnings of $3,604 million in 2009. The increase in 2010 earnings primarily resulted from higher prices for crude oil, natural gas, natural gas liquids and LNG. In addition, 2010 earnings benefitted from the $2,679 million after-tax gain on sale of Syncrude and higher gains from other asset rationalization efforts. These increases were partially offset by lower crude oil, natural gas and synthetic oil volumes, higher petroleum and export taxes as a result of higher prices, and the NMNG impairment. See the Business Environment and Executive Overview section for additional information on industry crude oil and natural gas prices.

U.S. E&P

U.S. E&P earnings increased 84 percent in 2010, from $1,503 million in 2009 to $2,768 million in 2010. The increase was primarily the result of higher prices for crude oil, natural gas and natural gas liquids. Earnings also benefitted from higher gains from asset sales in our Lower 48 portfolio and lower depreciation, depletion and amortization. These increases were partially offset by lower crude oil and natural gas volumes, higher production taxes, primarily in Alaska, and an unfavorable tax ruling.

U.S. E&P production averaged 686,000 BOE per day in 2010, a decrease of 9 percent from 755,000 BOE in 2009. The decrease was primarily due to field decline and unplanned downtime, which was somewhat offset by new production.

International E&P

International E&P earnings were $6,430 million in 2010, compared with $2,101 million in 2009. The increase in 2010 was mostly due to gains from the sale of Syncrude and other assets and higher crude oil, natural gas and LNG prices. These increases were partially offset by the NMNG impairment, lower synthetic oil and natural gas volumes, higher petroleum taxes as a result of higher prices and an $81 million after-tax charge to exploration expenses for project costs resulting from our decision to end participation in the Shah Gas Field Project in Abu Dhabi.

International E&P production averaged 1,066,000 BOE per day in 2010, a decrease of 3 percent from 1,099,000 BOE in 2009. The decrease was largely due to field decline, the impact of higher prices on production sharing arrangements and the sale of Syncrude. These decreases were partially offset by production from major projects, primarily in China, Canada, Qatar and Australia.

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.

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.

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 BOE per day 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 BOE per day 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 planned downtime.

Midstream

		2010	2009	2008
		Millions of Dollars		
Net Income Attributable to ConocoPhillips*	**$**	**306**	313	541
**Includes DCP Midstream-related earnings:*	*$*	***191***	*183*	*458*

		Dollars Per Barrel		
Average Sales Prices				
U.S. natural gas liquids*				
Consolidated	**$**	**45.42**	33.63	56.29
Equity affiliates		**41.28**	29.80	52.08

**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*	**193**	187	188
Natural gas liquids fractionated**	**152**	166	165

**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, trading and marketing businesses, primarily in the United States and Trinidad.

2010 vs. 2009

Midstream earnings decreased 2 percent in 2010. Higher natural gas liquids prices and, to a lesser extent, improved volumes from our equity affiliate, Phoenix Park Gas Processors Limited, were more than offset by the absence of the 2009 recognition of an $88 million after-tax benefit, which resulted from a DCP Midstream subsidiary converting subordinated units to common units. In addition, higher operating expenses resulting from higher turnaround activity contributed to the decrease in earnings.

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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 the $88 million after-tax benefit resulting from the conversion of subordinated units to common units.

R&M

		2010	2009	2008
		Millions of Dollars		
Net Income (Loss) Attributable to ConocoPhillips				
United States	$	**1,022**	(192)	1,540
International		**(830)**	229	782
	$	**192**	37	2,322

		Dollars Per Gallon		
U.S. Average Wholesale Prices*				
Gasoline	$	**2.24**	1.84	2.65
Distillates		**2.30**	1.76	3.06

**Excludes excise taxes.*

	Thousands of Barrels Daily		
Operating Statistics			
Refining operations*			
United States			
Crude oil capacity**	**1,986**	1,986	2,008
Crude oil processed	**1,782**	1,731	1,849
Capacity utilization (percent)	**90%**	87	92
Refinery production	**1,958**	1,891	2,035
International			
Crude oil capacity**	**671**	671	670
Crude oil processed	**374**	495	567
Capacity utilization (percent)	**56%**	74	85
Refinery production	**383**	504	575
Worldwide			
Crude oil capacity**	**2,657**	2,657	2,678
Crude oil processed	**2,156**	2,226	2,416
Capacity utilization (percent)	**81%**	84	90
Refinery production	**2,341**	2,395	2,610
Petroleum products sales volumes			
United States			
Gasoline	**1,120**	1,130	1,128
Distillates	**873**	858	893
Other products	**400**	367	374
	2,393	2,355	2,395

International	**647**	619	645
	3,040	2,974	3,040

**Includes our share of equity affiliates, except LUKOIL, which is included in the LUKOIL Investment segment.*
***Weighted-average crude oil capacity for the periods.*

Our R&M segment refines crude oil and other feedstocks into petroleum products (such as gasoline, distillates and aviation fuels); buys, sells and transports crude oil; and buys, transports, distributes and markets petroleum products. R&M has operations mainly in the United States, Europe and Asia.

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2010 vs. 2009

R&M reported earnings of $192 million in 2010, compared with earnings of $37 million in 2009. Earnings for 2010 included the $1,124 million after-tax property impairment of WRG. Excluding the impact of this impairment, earnings were significantly improved during 2010 due to higher global refining margins. Results also benefitted from a $113 million after-tax gain on the sale of CFJ and higher refining and marketing volumes. These increases were partially offset by negative foreign currency impacts. See the Business Environment and Executive Overview section for additional information on industry refining margins.

U.S. R&M

Earnings from U.S. R&M were $1,022 million in 2010, compared with a loss of $192 million in 2009. The increase in 2010 primarily resulted from significantly higher refining margins and the gain on sale of CFJ. Higher refining and marketing volumes also contributed to the improvement in earnings.

Our U.S. refining crude oil capacity utilization rate was 90 percent in 2010, compared with 87 percent in 2009. The increase in 2010 was primarily due to lower turnaround activity, lower run reductions due to market conditions, and less unplanned downtime.

International R&M

International R&M reported a loss of $830 million in 2010, compared with earnings of $229 million in 2009. The loss in 2010 primarily resulted from the WRG impairment and a $29 million after-tax impairment resulting from our decision to end participation in the Yanbu Refinery Project. Excluding these impairments, earnings were improved due to higher refining margins, partially offset by foreign currency losses.

Our international refining crude oil capacity utilization rate was 56 percent in 2010, compared with 74 percent in 2009. The 2010 rate primarily reflects run reductions at WRG in response to market conditions.

We are currently exploring options to either pursue the sale of WRG or operate it as a terminal. As a result, effective January 1, 2011, we no longer include its capacity in our stated refining capacities or our capacity utilization metrics.

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 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.

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 rate for 2009 was mainly affected by run reductions due to market conditions and increased turnaround activity, while the 2008 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.

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

LUKOIL Investment

	Millions of Dollars		
	2010	2009*	2008*
Net Income (Loss) Attributable to ConocoPhillips	$ **2,503**	1,219	(4,839)
Operating Statistics			
Crude oil production (thousands of barrels daily)	**284**	388	389
Natural gas production (millions of cubic feet daily)	**254**	295	330
Refinery crude oil processed (thousands of barrels daily)	**189**	240	226

**Recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information.*

This segment represents our investment in the ordinary shares of LUKOIL, an international, integrated oil and gas company headquartered in Russia.

Prior to 2010, our equity earnings for LUKOIL were estimated. Effective January 1, 2010, we changed our accounting to record our equity earnings for LUKOIL on a one-quarter-lag basis. This change in accounting principle has been applied retrospectively, by recasting prior period financial information. The performance metrics are also reported on a one-quarter-lag basis. See Note 2 Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for more information.

In addition to our equity share of LUKOIL s earnings, segment results include the amortization of the basis difference between our equity interest in the net assets of LUKOIL and the book value of our investment, as well as gains from the divestiture of our LUKOIL shares.

At year-end 2009, we had a 20 percent ownership interest in LUKOIL based on authorized and issued shares. In July 2010, we announced our intention to sell our entire interest in LUKOIL. During 2010, we sold approximately 151 million shares of LUKOIL, and as a result of these sales, our ownership interest in LUKOIL was 2.25 percent at December 31, 2010, based on authorized and issued shares. In the third quarter of 2010, our ownership interest declined to a level at which we were no longer able to exercise significant influence over the operating and financial policies of LUKOIL. Accordingly, at the end of the third quarter of 2010, we stopped applying the equity method of accounting for our remaining investment. In addition, we will no longer report proved reserves or production related to our LUKOIL investment. See Note 6 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for more information.

In the first quarter of 2011, we sold our remaining interest in LUKOIL. As a result, our first quarter 2011 earnings from the LUKOIL Investment segment will primarily reflect the realized gain on share sales. The total unrealized gain on those shares at December 31, 2010, based on a closing price of LUKOIL shares on the London Stock Exchange of $56.50 per share, was $158 million after-tax, and this amount was included in accumulated other comprehensive income.

2010 vs. 2009

LUKOIL segment earnings increased $1,284 million in 2010, which primarily resulted from the $1,251 million after-tax gain on our LUKOIL shares sold during 2010.

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2009 vs. 2008

LUKOIL segment earnings were $1,219 million in 2009, compared with a loss of $4,839 million in 2008. Results for 2008 included a $7,496 million noncash, before- and after-tax impairment of our LUKOIL investment taken during the fourth quarter. Excluding the impact of this impairment, earnings decreased 54 percent in 2009. The decrease was primarily due to lower realized refined product and crude oil prices, which was partly offset by lower extraction taxes and export tariff rates, and a benefit from basis difference amortization.

Chemicals

	Millions of Dollars		
	2010	2009	2008
Net Income Attributable to ConocoPhillips	**$ 498**	248	110

The Chemicals segment consists of our 50 percent interest in 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.

2010 vs. 2009

Earnings from the Chemicals segment increased $250 million in 2010, primarily due to substantially higher margins in the olefins and polyolefins business line and, to a lesser extent, improved margins from the specialties, aromatics and styrenics business line. Higher operating costs partially offset these increases.

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.

Emerging Businesses

	Millions of Dollars		
	2010	2009	2008
Net Income (Loss) Attributable to ConocoPhillips			
Power	**$ 49**	105	106
Other	**(108)**	(102)	(76)
	$ (59)	3	30

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, refining, alternative energy, biofuels, and the environment.

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2010 vs. 2009

The Emerging Businesses segment reported a loss of $59 million in 2010, compared with earnings of $3 million in 2009. The decrease for 2010 was mainly due to lower domestic and international power generation results, which resulted from higher operating costs and impairment charges related to a U.S. cogeneration plant that was sold in December 2010. Lower margins in international power and higher technology development expenses also contributed to the decrease.

2009 vs. 2008

Emerging Businesses reported earnings of $3 million in 2009, compared with $30 million in 2008. The decrease in 2009 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.

Corporate and Other

	Millions of Dollars		
	2010	2009	2008
Net Loss Attributable to ConocoPhillips			
Net interest	**$ (965)**	(851)	(558)
Corporate general and administrative expenses	**(209)**	(108)	(202)
Other	**(106)**	(51)	(274)
	$ (1,280)	(1,010)	(1,034)

2010 vs. 2009

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 13 percent in 2010, mostly due to a $114 million after-tax premium on early debt retirement and a lower effective tax rate. These increases were partially offset by lower interest expense due to lower debt levels. Corporate general and administrative expenses increased $101 million in 2010, primarily as a result of costs related to compensation and benefit plans. 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 primarily reflect foreign currency transaction losses.

2009 vs. 2008

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. Changes in the Other category are primarily due to foreign currency transaction gains in 2009, compared with foreign currency transaction losses in 2008.

CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars Except as Indicated		
	2010	2009	2008
Net cash provided by operating activities	**$ 17,045**	12,479	22,658
Short-term debt	**936**	1,728	370
Total debt	**23,592**	28,653	27,455
Total equity*	**69,109**	62,613	56,265
Percent of total debt to capital**	**25%**	31	33
Percent of floating-rate debt to total debt***	**10%**	9	37

**2009 and 2008 recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information.*

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

****Includes effect of interest rate swaps.*

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 2010, we received $15,372 million in proceeds from asset sales. During 2010, the primary uses of our available cash were: $9,761 million to support our ongoing capital expenditures and investments program, $5,202 million to repay debt, $3,866 million to repurchase common stock, $3,175 million to pay dividends on our common stock, and $982 million to purchase short-term investments. During 2010, cash and cash equivalents increased by $8,912 million to $9,454 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. 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 2010, cash of $17,045 million was provided by operating activities, a 37 percent increase from cash from operations of $12,479 million in 2009. The increase was primarily due to significantly higher crude oil prices in our E&P segment and higher refining margins in our R&M segment.

During 2009, cash flow from operations decreased $10,179 million, compared with 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.

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, bitumen, natural gas, LNG and natural gas liquids, as well as refining and marketing margins. Crude oil and natural gas prices deteriorated significantly in the fourth quarter of 2008. Crude oil prices trended higher in 2009 and 2010 although natural gas prices remained weak. Refining margins deteriorated significantly in the fourth quarter of 2008, remained low throughout 2009, and showed improvement during 2010. 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, bitumen, 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,

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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 E&P production for 2010 averaged 1.75 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 2011, excluding the impact of any additional dispositions, is expected to be approximately 1.7 million BOE per day. We continue to evaluate various properties as potential candidates for our disposition program. The makeup and timing of our disposition program will also impact 2011 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 2010 was negative 160 percent, including a positive 41 percent from consolidated operations. The 2010 reserve replacement reflects a reduction of 2.2 billion BOE due to LUKOIL share sales and other asset dispositions. Excluding the impact of acquisitions and dispositions, the E&P segment s reserve replacement was 138 percent of 2010 production. Over the five-year period ended December 31, 2010, our reserve replacement was 75 percent, including 105 percent from consolidated operations; however, excluding LUKOIL, our five-year reserve replacement would have been 111 percent. Over this period we added reserves through acquisitions and project developments, which were more than offset by the impact of asset expropriations in Venezuela and Ecuador and the sale of our investment in LUKOIL. 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; therefore, each year reserves may be revised upward or downward due to the impact of changes in commodity prices or as more technical data becomes available on reservoirs. In 2010 and 2009, 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 our R&M segment, 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 2010 were $15.4 billion, compared with $1.3 billion in 2009. The 2010 proceeds from asset sales included $8.3 billion from our interest in LUKOIL. The remaining sales consisted primarily of our interest in Syncrude Canada Ltd., CFJ Properties and North America E&P assets. We plan to raise an additional $3 billion through the end of 2011, as part of our previously announced $10 billion asset disposition program. The sale of our LUKOIL interest is not included in this program.

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Commercial Paper and Credit Facilities

At December 31, 2010, 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 (QG3) Project. At December 31, 2010 and 2009, 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, $1,182 million of commercial paper was outstanding at December 31, 2010, compared with $1,300 million at December 31, 2009. Since we had $1,182 million of commercial paper outstanding and had issued $40 million of letters of credit, we had access to $6.6 billion in borrowing capacity under our revolving credit facilities at December 31, 2010.

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.

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 and $500 million revolving credit facilities.

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, 2010, we were liable for certain contingent obligations under the following contractual arrangements:

Qatargas 3: We own a 30 percent interest in QG3, 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. QG3 secured project financing of $4 billion in 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

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ConocoPhillips loan facilities, will become nonrecourse to the project participants. At December 31, 2010, QG3 had approximately $4 billion outstanding under all the loan facilities, including the $1.2 billion from ConocoPhillips.

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. In the second quarter of 2010, the credit facilities were reduced, and our guarantee was released.

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, 2010, was $23.6 billion, a decrease of $5.1 billion during 2010, and our debt-to-capital ratio was 25 percent at year-end 2010, versus 31 percent at the end of 2009. The change in the debt-to-capital ratio was due to a combination of a decrease in debt and an increase in equity. Our debt-to-capital ratio target range is 20 to 25 percent. On February 15, 2011, a $328 million 9.375% Note was repaid at maturity.

In 2007, we closed on a business venture with Cenovus Energy Inc. 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. 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 $695 million was short-term and was included in the Accounts payable related parties line on our December 31, 2010, consolidated balance sheet. The principal portion of these payments, which totaled $659 million in 2010, 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.

We have provided loan financing to WRB Refining LP, to assist it in meeting its operating and capital spending requirements. At December 31, 2010, $550 million of such financing was outstanding and $400 million was classified as long term.

In February 2011, we announced a 20 percent increase in the quarterly dividend rate to 66 cents per share. The dividend is payable March 1, 2011, to stockholders of record at the close of business February 22, 2011.

On March 24, 2010, our Board of Directors authorized the purchase of up to $5 billion of our common stock through 2011. Repurchase of shares under this authorization totaled 64.5 million shares at a cost of $3.9 billion, through December 31, 2010. On February 11, 2011, the Board authorized the additional purchase of up to $10 billion of our common stock over the subsequent two years. At year end we had a cash and short-term investment balance of $10.4 billion, a significant portion of which is expected to be directed toward the repurchase of common stock.

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Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2010:

	Millions of Dollars				
	Payments Due by Period				
	Total	Up to 1 Year	Years 2-3	Years 4-5	After 5 Years
Debt obligations (a)	$ 23,553	924	3,354	3,137	16,138
Capital lease obligations	39	12	4	3	20
Total debt	23,592	936	3,358	3,140	16,158
Interest on debt and other obligations	20,060	1,404	2,649	2,274	13,733
Operating lease obligations	2,896	752	1,033	554	557
Purchase obligations (b)	139,575	61,136	14,326	9,044	55,069
Joint venture acquisition obligation (c)	5,009	695	1,504	1,672	1,138
Other long-term liabilities (d)					
Asset retirement obligations	8,776	454	722	627	6,973
Accrued environmental costs	994	117	176	119	582
Unrecognized tax benefits (e)	160	160	(e)	(e)	(e)
Total	$ 201,062	65,654	23,768	17,430	94,210

(a) Includes $457 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, 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 $73,138 million. In addition, $50,179 million are product purchases from CPChem, mostly for natural gas and natural gas liquids over the remaining term of 89 years, and Excel Paralubes, for base oil over the remaining initial term of 15 years.

Purchase obligations of $12,806 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 2011 through 2015 time period, we expect to contribute an average of $530 million per year to our qualified and nonqualified pension and postretirement benefit plans in the United States and an average of $240 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 $730 million for 2011 and then approximately $480 million per year for the remaining four years. Our required minimum funding in 2011 is expected to be $360 million in the United States and $160 million outside the United States.

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(e) Excludes unrecognized tax benefits of $965 million because the ultimate disposition and timing of any payments to be made with regard to such amounts 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			
	2011 Budget	**2010**	2009	2008
E&P				
United States Alaska	$ 900	**730**	810	1,414
United States Lower 48	3,300	**1,855**	2,664	3,836
International	7,100	**5,908**	5,425	11,206
	11,300	**8,493**	8,899	16,456
Midstream	-	**3**	5	4
R&M				
United States	1,000	**790**	1,299	1,643
International	200	**266**	427	626
	1,200	**1,056**	1,726	2,269
LUKOIL Investment	-	**-**	-	-
Chemicals	-	**-**	-	-
Emerging Businesses	100	**27**	97	156
Corporate and Other	200	**182**	134	214
	$ 12,800	**9,761**	10,861	19,099
United States	$ 5,400	**3,576**	4,921	7,111
International	7,400	**6,185**	5,940	11,988
	$ 12,800	**9,761**	10,861	19,099

Our capital expenditures and investments for the three-year period ending December 31, 2010, totaled $39.7 billion, with 85 percent allocated to our E&P segment.

Our capital expenditures and investments budget for 2011 is $12.8 billion. Included in this amount is approximately $0.4 billion in capitalized interest. We plan to direct 88 percent of the capital expenditures and investments budget to E&P and 9 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 2011 is approximately $13.5 billion.

E&P

Capital expenditures and investments for E&P during the three-year period ended December 31, 2010, totaled $33.8 billion. The expenditures over this period supported key exploration and development projects including:

Oil, natural gas liquids and natural gas developments in the Lower 48, including Texas, New Mexico, North Dakota, Oklahoma, Montana, Colorado, Wyoming, and offshore in the Gulf of Mexico (GOM).

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 (CBM) 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 Area, the Western North Slope and the Cook Inlet Area; and exploration.

Significant U.S. lease acquisitions in the federal waters of the Chukchi Sea offshore Alaska, as well as in the deepwater GOM.

- 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 development of the Britannia satellite fields, the development of the Jasmine discovery in the J-Block Area and development drilling on Clair and in the southern and central North Sea.
- Investment in Rockies Express Pipeline LLC.
- The North Belut Field, as well as other projects in offshore Block B and onshore South Sumatra in Indonesia.
- The QG3 Project, an integrated project to produce and liquefy natural gas from Qatar s North Field.
- The Gumusut-Kakap development offshore Sabah, Malaysia.
- Exploration activities in Australia s Browse Basin, deepwater GOM, onshore North American shale play and oil sands projects, offshore eastern Canada, North Sea and Kazakhstan s Block N.
- The El Merk Project, comprised of wells, gathering lines and a shared Central Processing Facility to develop the EMK Field Unit in Algeria.

2011 CAPITAL EXPENDITURES AND INVESTMENTS BUDGET

E&P s 2011 capital expenditures and investments budget is $11.3 billion, 33 percent higher than actual expenditures in 2010. Thirty-seven percent of E&P s 2011 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 Williston, Permian and San Juan Basins, as well as the Eagle Ford, Barnett and Lobo Trends. Also, we expect to direct capital spending towards exploration and appraisal activities in the Eagle Ford shale position in Texas, the Bakken shale formation in North Dakota and the deepwater GOM.

E&P is directing $7.1 billion of its 2011 capital expenditures and investments budget to international projects. Funds in 2011 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 CBM projects associated with the APLNG joint venture in Australia.
- 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, Southern North Sea assets, development of the Jasmine discovery in the J-Block Area and the Clair Ridge Project.
- The Kashagan Field in the Caspian Sea.
- Onshore developments in Nigeria, Algeria and Libya.

- Exploration and appraisal activities in North American shale plays and oil sands projects, Australia s Browse Basin, Kazakhstan s Block N, deepwater GOM, offshore Indonesia and the North Sea.

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, 2010, was primarily for air emission reduction and 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 $5.1 billion, which represented 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 225-ton per day sulfur plant at the Sweeny Refinery.
- Installation of facilities to reduce sulfur dioxide emissions from the Fluid Catalytic Cracker at the Alliance Refinery.
- Completion of a gasoline benzene reduction project at the Borger 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.
- Installations, revamps and expansions of equipment at several U.S. refineries to enable production of low benzene gasoline.
- U.S. programs aimed at air emission reductions.

2011 CAPITAL EXPENDITURES AND INVESTMENTS BUDGET

R&M s 2011 capital expenditures and investments budget is $1.2 billion, a 14 percent increase from actual spending in 2010, with about $1 billion targeted in the United States and $0.2 billion internationally. These funds will be used primarily for projects related to sustaining and improving the existing business with a focus on safety, regulatory compliance and reliability.

Emerging Businesses

Capital spending for Emerging Businesses during the three-year period ended December 31, 2010, was primarily for an expansion of the Immingham combined heat and power cogeneration plant near our Humber Refinery in the United Kingdom.

Contingencies

A number of lawsuits involving a variety of claims have been made against ConocoPhillips that arise in the ordinary course of business. We also may be required 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 active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. 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.

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

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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.

Legal and Tax Matters

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 and/or mediation. 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 regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, are required. See Note 20 Income Taxes, in the Notes to Consolidated Financial Statements, for additional information about income-tax-related contingencies.

Environmental

We are subject to the same numerous international, federal, state and local environmental laws and regulations as other companies in our industry. 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.

An example in the fuels area is the Energy Policy Act of 2005, which imposed obligations to provide increasing volumes of renewable fuels in transportation motor fuels through 2012. These obligations were changed with the enactment of the Energy Independence and Security Act of 2007. The 2007 law requires fuel producers and importers to provide additional renewable fuels for transportation motor fuels that include a mix of various types to be included 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.

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, 2009, 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, 2010, we had been notified of seven new sites, re-opened three sites and settled two sites, bringing the number to 73 unresolved sites with 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 $928 million in 2010 and are expected to be about $1,100 million per year in 2011 and 2012. Capitalized environmental costs were $574 million in 2010 and are expected to be about $650 million per year in 2011 and 2012.

Accrued liabilities for remediation activities 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.

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, 2010, our balance sheet included total accrued environmental costs of $994 million, compared with $1,017 million at December 31, 2009. 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 concerns 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 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.

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- 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 may 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.

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 2010, 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 $1,581 million and the accumulated impairment reserve was $497 million. The weighted-average judgmental percentage probability of ultimate failure was approximately 58 percent, and the weighted-average amortization period was approximately three years. If that judgmental percentage were to be raised by 5 percent across all calculations, pretax leasehold impairment expense in 2011 would increase by approximately $23 million. The remaining $5,374 million of gross capitalized unproved property costs at year-end 2010 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 $2.8 billion is concentrated in 10 major development areas. One of these major assets totaling $118 million is expected to move to proved properties in 2011.

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 2010, total suspended well costs were $1,013 million, compared with $908 million at year-end 2009. 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 approved operating 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 in the fourth quarter 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 2010, the net book value of productive E&P properties, plants and equipment subject to a unit-of-production calculation was approximately $56 billion and the depreciation,

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depletion and amortization recorded on these assets in 2010 was approximately $7.8 billion. The estimated proved developed reserves for our consolidated operations were 5.6 billion BOE at the beginning of 2010 and were 5.2 billion BOE at the end of 2010. 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 2010 would have increased by an estimated $410 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 in the fourth quarter 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 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. 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 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, 2010, we had $739 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, 2010, we had $3,633 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 $130 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $70 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.

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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, budget, continue, could, intend, may, plan, potential, predict, se 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, bitumen, natural gas, LNG 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 reserves and 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 chemicals products.

Lack of, or disruptions in, adequate and reliable transportation for our crude oil, natural gas, natural gas liquids, bitumen, 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, bitumen, natural gas, LNG, 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.

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 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 currency 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 Refining, Marketing and Transportation and Commercial monitors commodity price risk and also reports to the Chief Executive 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, bitumen, refined products, natural gas, natural gas liquids, LNG 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 capture market opportunities such as moving physical commodities to more profitable locations, storing commodities to capture seasonal or time premiums, and blending commodities to capture quality upgrades. Derivatives may be utilized to optimize these activities.

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, 2010, 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, 2010 and 2009, was immaterial to our cash flows and net income attributable to ConocoPhillips.

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The VaR for instruments held for purposes other than trading at December 31, 2010 and 2009, 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 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 effective rates 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 2010 and 2009 effective yield rate of 2.33 percent and 2.63 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 2010						
2011	**$ 853**	**7.62%**	**$ -**	**-%**	**$ 695**	**5.30%**
2012	**916**	**4.80**	**1,185**	**0.51**	**732**	**5.30**
2013	**1,262**	**5.33**	**-**	**-**	**772**	**5.30**
2014	**1,513**	**4.77**	**-**	**-**	**814**	**5.30**
2015	**1,514**	**4.62**	**64**	**2.05**	**858**	**5.30**
Remaining years	**15,291**	**6.44**	**498**	**0.38**	**1,138**	**5.30**
Total	**$ 21,349**		**$ 1,747**		**$ 5,009**	
Fair value	**$ 24,397**		**$ 1,747**		**$ 5,600**	
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	

During the second quarter of 2010, we executed interest rate swaps to synthetically convert $500 million of our 4.60% fixed-rate notes due in 2015 to a floating rate based on the London Interbank Offered Rate (LIBOR). These swaps qualify for and are designated as fair-value hedges using the short-cut method of hedge accounting. The short-cut method permits the assumption that changes in the value of the derivative perfectly offset changes in the value of the debt; therefore, no gain or loss has been recognized due to hedge ineffectiveness.

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The average pay rate is comprised of the LIBOR index rate and the swap spread. The swap spread consists primarily of the difference between the 4.60% fixed receive rate and the fixed rates for similar instruments at the time of execution.

	Millions of Dollars Except as Indicated			
	Interest Rate Derivatives			
Expected Maturity Date		Notional	Average Pay Rate	Average Receive Rate
Year-End 2010				
2011 2015	$	**-**	**-%**	**-%**
2015 fixed to variable		**500**	**2.33**	**4.60**
Remaining years		**-**	**-**	**-**
Total	$	**500**		
Fair Value	$	**20**		

Foreign Currency Exchange 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, 2010 and 2009, we held foreign currency exchange forwards hedging cross-border commercial activity and foreign currency exchange swaps hedging short-term intercompany loans between European subsidiaries and a U.S. subsidiary. Although these forwards and swaps hedge exposures to fluctuations in exchange rates, we elected not to utilize hedge accounting. As a result, the change in the fair value of these foreign currency exchange derivatives 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, and since our aggregate position in the forwards was not material, there would be no material impact to our income from an adverse hypothetical 10 percent change in the December 31, 2010 or 2009, exchange rates. The notional and fair market values of these positions at December 31, 2010 and 2009, were as follows:

		In Millions				
Foreign Currency Exchange Derivatives		Notional*			Fair Market Value**	
		2010	2009		**2010**	2009
Sell U.S. dollar, buy euro	USD	**-**	246	$	**-**	(2)
Sell U.S. dollar, buy British pound	USD	**4**	1,664		**(3)**	(16)
Sell U.S. dollar, buy Canadian dollar	USD	**562**	554		**8**	34
Sell U.S. dollar, buy Norwegian kroner	USD	**3**	744		**-**	(4)
Sell U.S. dollar, buy Australian dollar	USD	**-**	3		**-**	-
Sell euro, buy British pound	EUR	**253**	267		**1**	(14)

**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.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONOCOPHILLIPS

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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, 2010. 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, 2010.

Ernst & Young LLP has issued an audit report on the company s internal control over financial reporting as of December 31, 2010, and their report is included herein.

/s/ James J. Mulva

James J. Mulva
Chairman and
Chief Executive Officer
February 23, 2011

/s/ Jeff W. Sheets

Jeff W. Sheets
Senior Vice President, Finance
and Chief Financial Officer

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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, 2010 and 2009, 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, 2010. 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, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, 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 2010 ConocoPhillips changed the method used to determine its equity method share of LUKOIL s earnings. In addition, as discussed in Note 2, in 2009 ConocoPhillips 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, 2010, 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 23, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Houston, Texas
February 23, 2011

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, 2010, 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, 2010, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2010 consolidated financial statements of ConocoPhillips and our report dated February 23, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Houston, Texas
February 23, 2011

Consolidated Statement of Operations **ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2010	2009**	2008**
Revenues and Other Income			
Sales and other operating revenues*	$ **189,441**	149,341	240,842
Equity in earnings of affiliates	**3,133**	2,531	4,999
Gain on dispositions	**5,803**	160	891
Other income	**278**	358	199
Total Revenues and Other Income	**198,655**	152,390	246,931
Costs and Expenses			
Purchased crude oil, natural gas and products	**135,751**	102,433	168,663
Production and operating expenses	**10,635**	10,339	11,818
Selling, general and administrative expenses	**2,005**	1,830	2,229
Exploration expenses	**1,155**	1,182	1,337
Depreciation, depletion and amortization	**9,060**	9,295	9,012
Impairments			
Goodwill	**-**	-	25,443
LUKOIL investment	**-**	-	7,496
Other	**1,780**	535	1,686
Taxes other than income taxes*	**16,793**	15,529	20,637
Accretion on discounted liabilities	**447**	422	418
Interest and debt expense	**1,187**	1,289	935
Foreign currency transaction (gains) losses	**92**	(46)	117
Total Costs and Expenses	**178,905**	142,808	249,791
Income (loss) before income taxes	**19,750**	9,582	(2,860)
Provision for income taxes	**8,333**	5,090	13,419
Net income (loss)	**11,417**	4,492	(16,279)
Less: net income attributable to noncontrolling interests	**(59)**	(78)	(70)
Net Income (Loss) Attributable to ConocoPhillips	$ **11,358**	4,414	(16,349)
Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock *(dollars)*			
Basic	$ **7.68**	2.96	(10.73)
Diluted	**7.62**	2.94	(10.73)
Average Common Shares Outstanding *(in thousands)*			
Basic	**1,479,330**	1,487,650	1,523,432
Diluted	**1,491,067**	1,497,608	1,523,432

**Includes excise taxes on petroleum products sales:*	***$***	***13,689***	*13,325*	*15,418*

***Recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information. Also, certain amounts have been reclassified to conform to current-year presentation.*
See Notes to Consolidated Financial Statements.

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Consolidated Balance Sheet **ConocoPhillips**

At December 31		Millions of Dollars	
		2010	2009**
Assets			
Cash and cash equivalents	$	**9,454**	542
Short-term investments*		**973**	-
Accounts and notes receivable (net of allowance of $32 million in 2010 and $76 million in 2009)		**13,787**	11,861
Accounts and notes receivable related parties		**2,025**	1,354
Investment in LUKOIL		**1,083**	-
Inventories		**5,197**	4,940
Prepaid expenses and other current assets		**2,141**	2,470
Total Current Assets		**34,660**	21,167
Investments and long-term receivables		**31,581**	35,742
Loans and advances related parties		**2,180**	2,352
Net properties, plants and equipment		**82,554**	87,708
Goodwill		**3,633**	3,638
Intangibles		**801**	823
Other assets		**905**	708
Total Assets	$	**156,314**	152,138
Liabilities			
Accounts payable	$	**16,613**	14,168
Accounts payable related parties		**1,786**	1,317
Short-term debt		**936**	1,728
Accrued income and other taxes		**4,874**	3,402
Employee benefit obligations		**1,081**	846
Other accruals		**2,129**	2,234
Total Current Liabilities		**27,419**	23,695
Long-term debt		**22,656**	26,925
Asset retirement obligations and accrued environmental costs		**9,199**	8,713
Joint venture acquisition obligation related party		**4,314**	5,009
Deferred income taxes		**17,335**	17,956
Employee benefit obligations		**3,683**	4,130
Other liabilities and deferred credits		**2,599**	3,097
Total Liabilities		**87,205**	89,525
Equity			
Common stock (2,500,000,000 shares authorized at $.01 par value)			
Issued (2010 1,740,529,279 shares; 2009 1,733,345,558 shares)			
Par value		**17**	17

Capital in excess of par		**44,132**	43,681
Grantor trusts (at cost: 2010 36,890,375 shares; 2009 38,742,261 shares)		**(633)**	(667)
Treasury stock (at cost: 2010 272,873,537 shares; 2009 208,346,815 shares)		**(20,077)**	(16,211)
Accumulated other comprehensive income		**4,773**	3,065
Unearned employee compensation		**(47)**	(76)
Retained earnings		**40,397**	32,214
Total Common Stockholders Equity		**68,562**	62,023
Noncontrolling interests		**547**	590
Total Equity		**69,109**	62,613
Total Liabilities and Equity	**$**	**156,314**	152,138
**Includes marketable securities of:*	*$*	*602*	-

***Recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information.*

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Cash Flows **ConocoPhillips**

Years Ended December 31		Millions of Dollars		
		2010	2009*	2008*
Cash Flows From Operating Activities				
Net income (loss)	$	**11,417**	4,492	(16,279)
Adjustments to reconcile net income (loss) to net cash provided by operating activities				
Depreciation, depletion and amortization		**9,060**	9,295	9,012
Impairments		**1,780**	535	34,625
Dry hole costs and leasehold impairments		**477**	606	698
Accretion on discounted liabilities		**447**	422	418
Deferred taxes		**(878)**	(1,115)	(414)
Undistributed equity earnings		**(1,073)**	(1,254)	(2,357)
Gain on dispositions		**(5,803)**	(160)	(891)
Other		**(249)**	196	(1,135)
Working capital adjustments				
Decrease (increase) in accounts and notes receivable		**(2,427)**	(1,106)	4,225
Decrease (increase) in inventories		**(363)**	320	(1,321)
Decrease (increase) in prepaid expenses and other current assets		**43**	282	(724)
Increase (decrease) in accounts payable		**2,887**	1,612	(3,874)
Increase (decrease) in taxes and other accruals		**1,727**	(1,646)	675
Net Cash Provided by Operating Activities		**17,045**	12,479	22,658
Cash Flows From Investing Activities				
Capital expenditures and investments		**(9,761)**	(10,861)	(19,099)
Proceeds from asset dispositions		**15,372**	1,270	1,640
Purchases of short-term investments		**(982)**	-	-
Long-term advances/loans related parties		**(313)**	(525)	(163)
Collection of advances/loans related parties		**115**	93	34
Other		**234**	88	(28)
Net Cash Provided by (Used in) Investing Activities		**4,665**	(9,935)	(17,616)
Cash Flows From Financing Activities				
Issuance of debt		**118**	9,087	7,657
Repayment of debt		**(5,320)**	(7,858)	(1,897)
Issuance of company common stock		**133**	13	198
Repurchase of company common stock		**(3,866)**	-	(8,249)
Dividends paid on company common stock		**(3,175)**	(2,832)	(2,854)
Other		**(709)**	(1,265)	(619)
Net Cash Used in Financing Activities		**(12,819)**	(2,855)	(5,764)

Effect of Exchange Rate Changes on Cash and Cash Equivalents		**21**	98	21
Net Change in Cash and Cash Equivalents		**8,912**	(213)	(701)
Cash and cash equivalents at beginning of year		**542**	755	1,456
Cash and Cash Equivalents at End of Year	**$**	**9,454**	542	755

**Recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information.*

See Notes to Consolidated Financial Statements.

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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, 2007*	$ 17	42,724	(7,969)	(731)	4,560	(128)	49,861		1,173	89,507
Net income (loss)							(16,349)	(16,349)	70	(16,279)
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)								(22,784)	70	(22,714)
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							4,414	4,414	78	4,492
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								9,354	78	9,432
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)	32,214		590	62,613
Net income							**11,358**	**11,358**	**59**	**11,417**
Other comprehensive income (loss)										
Defined benefit pension plans										
Net prior service cost					**-**			**-**		**-**
Net actuarial gain					**133**			**133**		**133**
Nonsponsored plans					**13**			**13**		**13**
					158			**158**		**158**

Net unrealized gain on securities										
Foreign currency translation adjustments					**1,404**			**1,404**		**1,404**
Comprehensive income								**13,066**	**59**	**13,125**
Cash dividends paid on company common stock							**(3,175)**			**(3,175)**
Repurchase of company common stock			**(3,866)**							**(3,866)**
Distributions to noncontrolling interests and other									**(102)**	**(102)**
Distributed under benefit plans		**451**		**34**						**485**
Recognition of unearned compensation						**29**				**29**
December 31, 2010	**$ 17**	**44,132**	**(20,077)**	**(633)**	**4,773**	**(47)**	**40,397**		**547**	**69,109**

**Recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information.*
See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements **ConocoPhillips**

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. When we do not have the ability to exert significant influence, the investment is either classified as available-for-sale if fair value is readily determinable, or the cost method is used if fair value is not readily determinable. Undivided interests in oil and gas joint ventures, pipelines, natural gas plants and terminals are consolidated on a proportionate basis. Other securities and investments 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 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, bitumen, natural gas, liquefied natural gas (LNG), 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 producing properties 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 statement of operations 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 90 days or less from their date of purchase. They are carried at cost plus accrued interest, which approximates fair value.
- **Short-Term Investments** Investments in bank time deposits and marketable securities (commercial paper and government obligations) with original maturities of greater than 90 days but less than one year

are classified as short-term investments. See Note 16 Financial Instruments and Derivative Contracts, for additional information on these held-to-maturity financial instruments.

n **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.

n **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.

n **Derivative Instruments** Derivative instruments are recorded on the balance sheet at fair value. 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 are recognized in other comprehensive income and appear on the balance sheet in accumulated other comprehensive income 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.

n **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 resources 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.

n **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.

n **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.

n **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.

n **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).

n **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 in the fourth quarter 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

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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 downstream 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 the Gain on dispositions line of our consolidated statement of operations. 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.

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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.

n **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.

n **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 have 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.

n **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.

n **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.

n **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. For the purpose of the 2009 earnings per share calculation, net income attributable to ConocoPhillips was 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. 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.

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Note 2 Changes in Accounting Principles

LUKOIL Accounting

Effective January 1, 2010, we changed the method used to determine our equity-method share of OAO LUKOIL s earnings. Prior to 2010, we estimated our LUKOIL equity earnings for the current quarter based on current market indicators, publicly available LUKOIL information and other objective data. This earnings estimation process was necessary because, historically, LUKOIL s accounting cycle close and preparation of U.S. generally accepted accounting principles financial statements occurred subsequent to our reporting deadline, and for certain periods this timing gap exceeded 93 days. Although Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 323, Investments Equity Method and Joint Ventures, provides that when financial statements of an investee are not sufficiently timely, then the investor should record its share of earnings or loss based on the most recently available financial statements, U.S. Securities and Exchange Commission (SEC) guidance indicates this timing gap generally should not exceed 93 days. When the timing gap was reduced to less than 93 days for all reporting periods, we believed it was preferable to implement a change in accounting principle to record our equity-method share of LUKOIL s earnings on a one-quarter-lag basis, because it improves reporting reliability, while maintaining an acceptable level of relevance.

The following table summarizes the line items affected on the consolidated statement of operations for year ended December 31, 2010:

	Millions of Dollars		
	Computed with Estimate	As Reported with Lag	Effect of Change
Equity in earnings of affiliates	$ 2,951	3,133	182
Gain on dispositions	5,593	5,803	210
Provision for income taxes	8,343	8,333	(10)
Net income	11,015	11,417	402
Net income attributable to ConocoPhillips	10,956	11,358	402
Net income attributable to ConocoPhillips per share of common stock (dollars)			
Basic	$ 7.41	7.68	.27
Diluted	7.35	7.62	.27

The following table summarizes the line items affected on the consolidated balance sheet at December 31, 2010:

	Millions of Dollars		
	Computed with Estimate	As Reported with Lag	Effect of Change
Accrued income and other taxes	$ 4,865	4,874	9
Accumulated other comprehensive income	4,741	4,773	32
Retained earnings	40,438	40,397	(41)

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The following table summarizes the line items affected on the 2010 consolidated statement of cash flows for year ended December 31, 2010:

	Millions of Dollars		
	Computed with Estimate	As Reported with Lag	Effect of Change
Net income	$ 11,015	11,417	402
Deferred taxes	(868)	(878)	(10)
Undistributed equity earnings	(891)	(1,073)	(182)
Gain on dispositions	(5,593)	(5,803)	(210)

This change in accounting principle to a one-quarter lag under ASC Topic 323 has been applied retrospectively, by recasting prior period financial information. The following table summarizes the line items affected on the consolidated statement of operations for years ended December 31:

	Millions of Dollars					
	2009			2008		
	As Originally Reported	As Adjusted	Effect of Change	As Originally Reported	As Adjusted	Effect of Change
Equity in earnings of affiliates	$ 2,981	2,531	(450)	4,250	4,999	749
Impairment LUKOIL investment	-	-	-	7,410	7,496	86
Provision for income taxes	5,096	5,090	(6)	13,405	13,419	14
Net income (loss)	4,936	4,492	(444)	(16,928)	(16,279)	649
Net income (loss) attributable to ConocoPhillips	4,858	4,414	(444)	(16,998)	(16,349)	649
Net income (loss) attributable to ConocoPhillips per share of common stock (dollars)						
Basic	$ 3.26	2.96	(.30)	(11.16)	(10.73)	.43
Diluted	3.24	2.94	(.30)	(11.16)	(10.73)	.43

The following table summarizes the line items affected on the consolidated balance sheet at December 31, 2009:

	Millions of Dollars		
	As Originally Reported	As Reported with Lag	Effect of Change
Investments and long-term receivables	$ 36,192	35,742	(450)
Deferred income taxes	17,962	17,956	(6)
Retained earnings	32,658	32,214	(444)

The cumulative impact to retained earnings as of January 1, 2008, was a decrease of $649 million as a result of the accounting change.

The following table summarizes the line items affected on the consolidated statement of cash flows for years ended December 31:

	Millions of Dollars					
	2009			2008		
	As Originally Reported	As Adjusted	Effect of Change	As Originally Reported	As Adjusted	Effect of Change
Net income (loss)	$ 4,936	4,492	(444)	(16,928)	(16,279)	649
Impairments	535	535	-	34,539	34,625	86
Deferred taxes	(1,109)	(1,115)	(6)	(428)	(414)	14
Undistributed equity earnings	(1,704)	(1,254)	450	(1,609)	(2,357)	(748)
Other	196	196	-	(1,134)	(1,135)	(1)

See Note 6 Investments, Loans and Long-Term Receivables, for additional information relating to our LUKOIL investment.

Transfers of Financial Assets

In June 2009, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 166, Accounting for Transfers of Financial Assets, an amendment of FASB Statement No. 140, which was codified into FASB ASC Topic 860, Transfers and Servicing. This Statement removed the concept of a qualifying special purpose entity (SPE) and the exception for qualifying SPEs from the consolidation guidance. Additionally, the Statement clarified the requirements for financial asset transfers eligible for sale accounting. This Statement was effective January 1, 2010, and did not impact our consolidated financial statements.

Variable Interest Entities (VIEs)

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, Topic 810 requires a qualitative rather than a quantitative approach to determine the primary beneficiary of a VIE, it amended certain guidance pertaining to the determination of the primary beneficiary when related parties are involved, and it amended 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 was effective January 1, 2010, and its adoption did not impact our consolidated financial statements, other than the required disclosures. For additional information, see Note 3 Variable Interest Entities (VIEs).

Reserve Estimation and Disclosures

In January 2010, the FASB issued Accounting Standards Update (ASU) No. 2010-03, Oil and Gas Reserve Estimation and Disclosures. This ASU amended the FASB s ASC Topic 932, Extractive Activities Oil and Gas to align the accounting requirements of Topic 932 with the SEC s final rule, Modernization of the Oil and Gas Reporting Requirements issued on December 31, 2008. In summary, the revisions in ASU 2010-03 modernized the disclosure rules to better align with current industry practices and expanded 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.

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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.

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 statement of operations. Additionally, Topic 810 clarified 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 assets, liabilities, 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.

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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 defined fair value, established a framework for its measurement and expanded 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.

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 clarified that an entity shall continue to use the cost accumulation model for its equity method investments. It also confirmed 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.

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.

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 LUKOIL have disproportionate interests, and LUKOIL was a related party at inception of the joint venture. Since LUKOIL is no longer a related party, we do not believe NMNG would be a VIE if reconsidered today. LUKOIL owns 70 percent versus our 30 percent direct interest; therefore, 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. At December 31, 2010, the book value of our investment in the venture was $735 million.

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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, 2010, was $653 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.

Note 4 Inventories

Inventories at December 31 were:

	Millions of Dollars	
	2010	2009
Crude oil and petroleum products	$ **4,254**	3,955
Materials, supplies and other	**943**	985
	$ **5,197**	4,940

Inventories valued on the LIFO basis totaled $4,051 million and $3,747 million at December 31, 2010 and 2009, respectively. The excess of current replacement cost over LIFO cost of inventories amounted to $6,794 million and $5,627 million at December 31, 2010 and 2009, respectively.

Note 5 Assets Held for Sale

In the fourth quarter of 2009, we announced plans to raise approximately $10 billion from asset sales through the end of 2011. At December 31, 2009, we classified $323 million of Refining and Marketing (R&M) noncurrent assets, primarily investment in equity affiliates, and $75 million of R&M noncurrent deferred income tax liabilities as held for sale. During 2010, these assets and others were sold. While we continue to market and evaluate other assets for sale under this program that may be sold in 2011, we did not have significant assets meeting the criteria to be classified as held for sale as of December 31, 2010.

On June 25, 2010, we sold our 9.03 percent interest in the Syncrude Canada Ltd. joint venture for $4.6 billion. The $2.9 billion before-tax gain was included in the Gain on dispositions line of our consolidated statement of operations. The cash proceeds were included in the Proceeds from asset dispositions line within the investing cash flow section of our consolidated statement of cash flows. At the time of disposition, Syncrude had a net carrying value of $1.75 billion, which included $1.97 billion of properties, plants and equipment. During 2010 until its disposition, Syncrude contributed $327 million in intercompany sales and other operating revenues, and generated income before taxes of $127 million and net income of $93 million for the E&P segment.

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Note 6 Investments, Loans and Long-Term Receivables

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

	Millions of Dollars	
	2010	2009
Equity investments*	**$ 30,055**	34,280
Loans and advances related parties	**2,180**	2,352
Long-term receivables	**922**	1,009
Other investments	**604**	453
	$ 33,761	38,094

**2009 recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information.*

Equity Investments

Affiliated companies in which we had a significant equity investment at December 31, 2010 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 LP 50 percent owned business venture with Cenovus owns the Wood River and Borger Refineries, which process crude oil into refined products.

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 includes LUKOIL until loss of significant influence):

	Millions of Dollars		
	2010	2009	2008
Revenues	**$ 105,589**	128,881	180,070
Income before income taxes	**11,250**	12,121	22,356
Net income	**9,495**	9,145	17,976
Current assets	**14,039**	36,139	34,838
Noncurrent assets	**79,411**	126,163	114,294
Current liabilities	**9,325**	22,483	21,150
Noncurrent liabilities	**24,412**	30,960	29,845

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, 2010, retained earnings included $1,991 million related to the undistributed earnings of affiliated companies.

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 our agreements with Origin Energy, we will potentially make up to four additional payments to Origin of $500 million each. The payments are conditional on up to four LNG trains being approved and developed by the joint venture and achievement of certain other financial and operating milestones.

At December 31, 2010, the book value of our equity method investment in APLNG was $9,159 million, which includes $3,244 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 $1,187 million, resulting in a basis difference of $7,948 million on our books. The amortizable portion of the basis difference, $5,719 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 2010, 2009 and 2008 was after-tax expense of $5 million, $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 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 partnership, WRB Refining LP. 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, 2010, the book value of our investment in FCCL was $8,674 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, 2010, the book value of our investment in WRB was $3,222 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 26 years, which is the estimated remaining useful life of the refineries property, plant and equipment at the closing date. The basis difference at December 31, 2010, was $4,101 million. Equity earnings in 2010, 2009 and 2008 were increased by $243 million, $209 million and $246 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. Our ownership interest was 2.25 percent at December 31, 2010, and 20 percent at December 31, 2009 and 2008, 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 equity method ownership interest. Our ownership interest, based on estimated shares outstanding at December 31, 2009 and 2008, was 20.09 percent and 20.06 percent, respectively.

On July 28, 2010, we announced our intention to sell our entire interest in LUKOIL, then consisting of 163.4 million shares. This decision was implemented as follows:

> On July 28, 2010, we entered into a stock purchase and option agreement (the Agreement) with a wholly owned subsidiary of LUKOIL, pursuant to which such subsidiary purchased 64.6 million shares from us at a price of $53.25 per share, or $3,442 million in total. This transaction closed on August 16, 2010.
>
> Also pursuant to the Agreement, the LUKOIL subsidiary had a 60-day option, expiring on September 26, 2010, to purchase any or all of our interest remaining at the time of exercise of the option, at a price of $56 per share. Upon exercise of this option, we sold 42.5 million shares on September 29, 2010, for proceeds of $2,380 million.
>
> Finally, we sold our remaining shares in the open market subject to the terms of the Shareholder Agreement, with the final disposition of all shares occurring in the first quarter of 2011.

During the third quarter of 2010, our ownership interest declined to a level at which we were no longer able to exercise significant influence over the operating and financial policies of LUKOIL. Accordingly, at the end of the third quarter of 2010, we stopped applying the equity method of accounting for our remaining investment in LUKOIL, and we reclassified the investment from Investments and long-term receivables to current assets on our consolidated balance sheet as an available-for-sale equity security.

In total, during 2010, we sold 151 million shares of LUKOIL for $8,345 million, realizing a before-tax gain on disposition of $1,749 million, which was included in the Gain on dispositions line of our consolidated statement of operations. Included in these amounts are sales proceeds of $1,793 million and a realized before-tax gain of $437 million incurred subsequent to classifying the investment as available-for-sale. The cost basis for shares sold is average cost.

At December 31, 2010, our remaining investment in LUKOIL was carried at fair value of $1,083 million, reflecting a closing price of LUKOIL American Depositary Receipts (ADRs) on the London Stock Exchange of $56.50 per share. The carrying value reflects a pretax unrealized gain over our cost basis of $247 million. This unrealized gain, net of related income taxes, is reported as a component of accumulated other comprehensive income. The fair value is categorized as Level 1 in the fair value hierarchy.

Prior to 2010, our equity earnings for LUKOIL were estimated. Effective January 1, 2010, we changed our accounting to record our equity earnings for LUKOIL on a one-quarter-lag basis. See Note 2 Changes in Accounting Principles, for additional information about this change in accounting principle for our LUKOIL investment.

While applying the equity method of accounting, a negative basis difference existed which was primarily amortized on a straight-line basis over a 22-year useful life as an increase to equity earnings. Equity earnings in 2010 and 2009 were increased $155 million and $157 million, respectively, while equity earnings in 2008 were reduced $86 million due to amortization of the positive basis difference that existed prior to the 2008 year-end investment impairment discussed below.

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 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 at year-end 2008 was $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 had 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 $7,496 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.

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, 2010, the book value of our equity method investment in NMNG was $735 million. NMNG achieved initial production of the YK Field in June 2008, and development was completed in 2010. 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 2010 and 2009, we reduced the carrying value of our NMNG investment, reflecting other-than-temporary declines in fair value.

DCP Midstream

DCP Midstream owns and operates gas plants, gathering systems, storage facilities and fractionation plants. At December 31, 2010, the book value of our equity method investment in DCP Midstream was $1,038 million. DCP Midstream markets a portion of its natural gas liquids to us and CPChem under a supply agreement that continues at the current volume commitment with a primary term ending December 31, 2014. 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, 2010, the book value of our equity method investment in CPChem was $2,518 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 and Long-term Receivables

As part of our normal ongoing business operations and consistent with industry practice, we enter into numerous agreements with other parties to pursue business opportunities. Included in such activity are loans and long-term receivables to certain affiliated and non-affiliated companies. Loans are recorded when cash is transferred or seller financing is provided to the affiliated or non-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 and long-term receivables are assessed for impairment when events indicate the loan balance may not be fully recovered.

At December 31, 2010, significant loans to affiliated companies include the following:

- $653 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 2008 and is required to continue making repayments through full repayment of the loan in 2026. Repayment by Freeport is supported by process-or-pay capacity service payments made by us to Freeport under our terminal use agreement.
- $1,118 million of project financing and an additional $96 million of accrued interest to Qatar Liquefied Gas Company Limited (3) (QG3), which is an integrated project to produce and liquefy natural gas from Qatar s North Field. We own a 30 percent interest in QG3, for which we use the equity method of accounting. The other participants in the project are affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent). QG3 secured project financing of $4.0 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, 2010, QG3 had approximately $4.0 billion outstanding under all the loan facilities. Bi-annual repayments began in January 2011 and will extend through July 2022.

$550 million of loan financing to WRB Refining LP to assist it in meeting its operating and capital spending requirements. We have certain creditor rights in case of default or insolvency.

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.

At September 30, 2010, the Varandey Terminal Company was no longer considered a related party. Accordingly, the long-term portion of this loan is included in the Investments and long-term receivables line of the consolidated balance sheet, while the short-term portion is in Prepaid expenses and other current assets.

At December 31, 2010, significant long-term receivables and loans to non-affiliated companies included $372 million related to seller financing of U.S. retail marketing assets. In January 2009, we closed on the sale of a large part of our U.S. retail marketing assets which included a five-year note to finance the sale of certain assets. The note is collateralized by the underlying assets related to the sale.

Long-term receivables and the long-term portion of these loans are included in the Investments and long-term receivables line on the consolidated balance sheet, while the short-term portion related to non-affiliate loans is in Accounts and notes receivable.

Other

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, 2010, was $325 million, and at December 31, 2009, was $338 million. 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. MSLP processes our long residue, which is produced from heavy sour crude oil, for a processing fee. Fuel-grade petroleum coke is produced as a by-product and becomes the property of MSLP. 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. PDVSA has initiated arbitration with the International Chamber of Commerce challenging our actions, and this arbitration is underway. 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					
	2010			2009		
	Gross PP&E	Accum. DD&A	Net PP&E	Gross PP&E	Accum. DD&A	Net PP&E
E&P	**$ 116,805**	**50,501**	**66,304**	115,224	45,577	69,647
Midstream	**128**	**80**	**48**	123	74	49
R&M	**23,579**	**8,999**	**14,580**	23,047	6,714	16,333
LUKOIL Investment	**-**	**-**	**-**	-	-	-
Chemicals	**-**	**-**	**-**	-	-	-
Emerging Businesses	**981**	**161**	**820**	1,198	300	898
Corporate and Other	**1,732**	**930**	**802**	1,650	869	781
	$ 143,225	**60,671**	**82,554**	141,242	53,534	87,708

Note 8 Suspended Wells

The following table reflects the net changes in suspended exploratory well costs during 2010, 2009 and 2008:

	Millions of Dollars		
	2010	2009	2008
Beginning balance at January 1	**$ 908**	660	589
Additions pending the determination of proved reserves	**216**	342	160
Reclassifications to proved properties	**(106)**	(39)	(37)
Sales of suspended well investment	**(4)**	(21)	(10)
Charged to dry hole expense	**(1)**	(34)	(42)
Ending balance at December 31	**$ 1,013**	908	660

The following table provides an aging of suspended well balances at December 31, 2010, 2009 and 2008:

	Millions of Dollars		
	2010	2009	2008
Exploratory well costs capitalized for a period of one year or less	**$ 220**	319	182
Exploratory well costs capitalized for a period greater than one year	**793**	589	478
Ending balance	**$ 1,013**	908	660

Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	**40**	34	31

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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, 2010:

		Millions of Dollars			
			Suspended Since		
Project		Total	2007-2009	2004-2006	2001-2003
Aktote Kazakhstan[1]	$	19	-	8	11
Alpine satellite Alaska[1]		23	-	-	23
Browse Basin Australia[2]		93	93	-	-
Caldita/Barossa Australia[2]		77	-	77	-
Clair U.K.[1]		46	29	17	-
Fiord West Alaska[1]		16	16	-	-
Harrison U.K.[1]		15	15	-	-
Kairan Kazakhstan[1]		27	14	13	-
Kalamkas Kazakhstan[2]		13	4	5	4
Kashagan Kazakhstan[2]		44	34	-	10
Malikai Malaysia[1]		53	-	53	-
NPR-A Alaska[1]		17	17	-	-
Petai/Pisagon Malaysia[2]		43	33	10	-
Saleski Canada[2]		14	14	-	-
Shenandoah Lower 48[2]		43	43	-	-
Sunrise 3 Australia[1]		13	13	-	-
Surmont Beyond Phase II Canada[2]		28	19	9	-
Thornbury Canada[2]		20	20	-	-
Tiber Lower 48[2]		40	40	-	-
Titan Norway[1]		12	12	-	-
Ubah Malaysia[1]		24	24	-	-
Uge Nigeria[2]		30	16	14	-
Eighteen projects of $10 million or less each[1][2]		83	59	24	-
Total of 40 projects	$	793	515	230	48

(1) Appraisal drilling complete; costs being incurred to assess development.
(2) Additional appraisal wells planned.

Note 9 Goodwill and Intangibles

Goodwill

Changes in the carrying amount of goodwill were as follows:

		Millions of Dollars					
			2010			2009	
		E&P	R&M	Total	E&P	R&M	Total
Balance as of January 1							
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 allocated to assets held for sale or sold	**-**	**-**	**-**	-	(135)	(135)
Tax and other adjustments	**-**	**(5)**	**(5)**	-	(5)	(5)
Balance as of December 31						
Goodwill	**25,443**	**3,633**	**29,076**	25,443	3,638	29,081
Accumulated impairment losses	**(25,443)**	**-**	**(25,443)**	(25,443)	-	(25,443)
	$ -	**3,633**	**3,633**	-	3,638	3,638

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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 of 2008, 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 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 at December 31 on the carrying value of intangible assets follows:

		Millions of Dollars Gross Carrying Amount	
		2010	2009
Indefinite-Lived Intangible Assets			
Trade names and trademarks	$	**494**	494
Refinery air and operating permits		**245**	246
	$	**739**	740

At year-end 2010, our amortized intangible asset balance was $62 million, compared with $83 million at year-end 2009. Amortization expense was not material for 2010 and 2009, and is not expected to be material in future years.

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, in the Notes to Consolidated Financial Statements, for information on the impairment of our LUKOIL investment.

Other Impairments

During 2010, 2009 and 2008, we recognized the following before-tax impairment charges, excluding the goodwill and LUKOIL investment impairments noted above:

		Millions of Dollars		
		2010	2009	2008
E&P				
United States	$	**25**	5	620
International		**56**	463	173
R&M				
United States		**52**	63	534
International		**1,616**	3	181
Emerging Businesses		**31**	-	130
Corporate		**-**	1	48
	$	**1,780**	535	1,686

2010

During 2010, we recorded a $1,514 million impairment of our refinery in Wilhelmshaven, Germany, due to canceled plans for a project to upgrade the refinery, as well as a $98 million impairment as a result of our decision to end our participation in a new refinery project in Yanbu Industrial City, Saudi Arabia. We also recorded various property impairments of $81 million in our E&P segment.

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 costs and capital expenditure assumptions. Additionally, 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, due to their

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expropriation. An arbitration hearing on case merits regarding the expropriation is scheduled for March 2011.
Property impairments of $66 million in our R&M segment, primarily associated with planned asset dispositions, were also recorded during 2009.

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, which 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.

Fair Value Remeasurements

The following table shows the values of assets, 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		
	Fair Value*	Level 1 Inputs	Level 3 Inputs	Before-Tax Loss
Year ended December 31, 2010				
Net properties, plants and equipment (held for use)	**$ 307**	**-**	**307**	**1,604******
Net properties, plants and equipment (held for sale)	**23**	**5**	**18**	**43**
Equity method investments	**735**	**-**	**735**	**645**
Year ended December 31, 2009				
Net properties, plants and equipment (held for use)	$ 210	-	210	385
Net properties, plants and equipment (held for sale)	121	35	86	62
Equity method investments	1,784	-	1,784	286

**Represents the fair value at the time of the impairment.*
***Includes a $55 million leasehold impairment charged to exploration expenses.*

2010

During 2010, net properties, plants and equipment held for use with a carrying amount of $1,911 million were written down to a fair value of $307 million, resulting in a before-tax loss of $1,604 million. The fair values were determined by the use of internal discounted cash flow models using estimates of future production, prices, costs and a discount rate believed to be consistent with those used by principal market participants and cash flow multiples for similar assets and alternative use.

Also during 2010, net properties, plants and equipment held for sale with a carrying amount of $64 million were written down to their fair value of $23 million less cost to sell of $2 million for a net $21 million, resulting in a before-tax loss of $43 million. The fair values were primarily determined by binding negotiated selling prices with third parties, with some adjusted for the fair value of certain liabilities retained.

In addition, an equity method investment associated with our E&P segment was determined to have a fair value below carrying amount, and the impairment was considered to be other than temporary. This investment with a book value of $1,380 million was written down to a fair value of $735 million, resulting in a charge of $645 million before-tax, which is included in the Equity in earnings of affiliates line of our consolidated statement of operations. The fair value was determined by the application of an internal discounted cash flow model using estimates of future production, prices, costs and a discount rate believed to be consistent with those used by principal market participants. In addition, the equity investment fair value considered market analysis of certain similar undeveloped properties.

2009

In 2009, 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.

Also during 2009, 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 2009), 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.

Note 11 Asset Retirement Obligations and Accrued Environmental Costs

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

	Millions of Dollars	
	2010	2009
Asset retirement obligations	$ **8,776**	8,295
Accrued environmental costs	**994**	1,017
Total asset retirement obligations and accrued environmental costs	**9,770**	9,312
Asset retirement obligations and accrued environmental costs due within one year*	**(571)**	(599)
Long-term asset retirement obligations and accrued environmental costs	$ **9,199**	8,713

**Classified as a current liability on the balance sheet, under the caption Other accruals.*

Asset Retirement Obligations

We 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, we capitalize the associated asset retirement 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.

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During 2010 and 2009, our overall asset retirement obligation changed as follows:

		Millions of Dollars	
		2010	2009
Balance at January 1	$	**8,295**	6,615
Accretion of discount		**422**	394
New obligations		**64**	113
Changes in estimates of existing obligations		**744**	905
Spending on existing obligations		**(314)**	(322)
Property dispositions		**(394)**	(82)
Foreign currency translation		**(41)**	672
Balance at December 31	$	**8,776**	8,295

Accrued Environmental Costs

Total accrued environmental costs at December 31, 2010 and 2009, were $994 million and $1,017 million, respectively. The 2010 decrease in total accrued environmental costs is due to payments and settlements during the year exceeding new accruals, accrual adjustments and accretion.

We had accrued environmental costs of $624 million and $632 million at December 31, 2010 and 2009, 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 $278 million and $292 million of environmental costs associated with nonoperator sites at December 31, 2010 and 2009, respectively. In addition, $92 million and $93 million were included at both December 31, 2010 and 2009, respectively, 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 are expected to 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 $452 million at December 31, 2010. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $54 million in 2011, $38 million in 2012, $41 million in 2013, $30 million in 2014, $28 million in 2015, and $342 million for all future years after 2015.

Note 12 Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2010	2009
9.875% Debentures due 2010	**$ -**	150
9.375% Notes due 2011	**328**	328
9.125% Debentures due 2021	**150**	150
8.75% Notes due 2010	**-**	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	**15**	23
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
6.65% Debentures due 2018	**297**	297
6.50% Notes due 2011	**500**	500
6.50% Notes due 2039	**2,250**	2,250
6.50% Notes due 2039	**500**	500
6.40% Notes due 2011	**-**	178
6.35% Notes due 2011	**-**	1,750
6.00% Notes due 2020	**1,000**	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**	2,250
5.625% Notes due 2016	**1,250**	1,250
5.50% Notes due 2013	**750**	750
5.30% Notes due 2012	**-**	350
5.20% Notes due 2018	**500**	500
4.75% Notes due 2012	**897**	897
4.75% Notes due 2014	**1,500**	1,500
4.60% Notes due 2015	**1,500**	1,500
4.40% Notes due 2013	**400**	400
Commercial paper at 0.14% 0.34% at year-end 2010 and 0.06% 0.29% at year-end 2009	**1,182**	1,300
Floating Rate Five-Year Term Note due 2011 at 0.575% at year-end 2010 and 0.45% at year-end 2009	**-**	750

Industrial Development Bonds due 2012 through 2038 at 0.33% 5.75% at year-end 2010 and 0.24% 5.75% at year-end 2009	**252**	252
Guarantee of savings plan bank loan payable due 2015 at 2.06% at year-end 2010 and 2.01% at year-end 2009	**64**	103
Note payable to Merey Sweeny, L.P. due 2020 at 7% (related party)	**144**	154
Marine Terminal Revenue Refunding Bonds due 2031 at 0.33% 0.48% at year-end 2010 and 0.26% 0.40% at year-end 2009	**265**	265
Other	**31**	38
Debt at face value	**23,096**	28,120
Capitalized leases	**39**	31
Net unamortized premiums and discounts	**457**	502
Total debt	**23,592**	28,653
Short-term debt	**(936)**	(1,728)
Long-term debt	**$ 22,656**	26,925

Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2011 through 2015 are: $936 million, $2,081 million, $1,277 million, $1,530 million and $1,610 million, respectively. At December 31, 2010, we had classified $1,125 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.

During 2010, the following debt instruments were repaid prior to their maturity:

- The $400 million 6.68% Notes due 2011.
- The $178 million 6.40% Notes due 2011.
- The $1,750 million 6.35% Notes due 2011.
- The $350 million 5.30% Notes due 2012.
- The $750 million remaining balance of the Floating Rate Five-Year Term Note due 2011.

During 2010, the following debt instruments were repaid at their maturity:

- The $150 million 9.875% Debentures due 2010.
- The $1,264 million 8.75% Notes due 2010.

At December 31, 2010, 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, 2010 and 2009, 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 $1,182 million of commercial paper outstanding at December 31, 2010, compared with $1,300 million at December 31, 2009. Since we had $1,182 million of commercial paper outstanding and had issued $40 million of letters of credit, we had access to $6.6 billion in borrowing capacity under our revolving credit facilities at December 31, 2010.

Note 13 Joint Venture Acquisition Obligation

In 2007, we closed on a business venture with 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.

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, $695 million was short-term and was included in the Accounts payable related parties line on our December 31, 2010, consolidated balance sheet. The principal portion of these payments, which totaled $659 million in 2010, 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, 2010, 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, 2010, the carrying value of the guarantee to third-party lenders was $11 million.

Guarantees of Joint Venture Debt

At December 31, 2010, we had guarantees outstanding for our portion of joint venture debt obligations, which have terms of up to 15 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 6 to 21 years. Our maximum potential amount of future payments, or cost of volume delivery, under these guarantees is estimated to be $1,578 million ($3,477 million in the event of intentional or reckless breach) at December 2010 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 co-venturers do not make necessary equity contributions into APLNG.

We have other guarantees with maximum future potential payment amounts totaling $400 million, which consist primarily of 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. These guarantees generally extend up to 14 years or life of the venture.

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, 2010, was $386 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 $250 million of environmental accruals for known contamination that are included in asset retirement obligations and accrued environmental costs at December 31, 2010. For additional information about environmental liabilities, see Note 15 Contingencies and Commitments.

Note 15 Contingencies and Commitments

A number of lawsuits involving a variety of claims have been made against ConocoPhillips that arise in the ordinary course of business. We also may be required 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 active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. 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. 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. 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 and/or mediation. 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 regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, are required.

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, 2010, we had performance obligations secured by letters of credit of $1,784 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.

In 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. As a result, Venezuela s national oil company, PDVSA, or its affiliates directly assumed control over ConocoPhillips interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project. In response to this expropriation, we filed a request for international arbitration on November 2, 2007, with the World Bank s International Centre for Settlement of Investment Disputes (ICSID). An arbitration hearing was held during 2010 before ICSID. We are awaiting their decision. See Note 10 Impairments, for additional information about expropriated assets in Ecuador.

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: 2011 $369 million; 2012 $410 million; 2013 $408 million; 2014 $408 million; 2015 $400 million; and 2016 and after $4,402 million. Total payments under the agreements were $216 million in 2010, $114 million in 2009 and $119 million in 2008.

Note 16 Financial Instruments and Derivative Contracts
Financial Instruments
We invest excess cash in financial instruments with maturities based on our cash forecasts for the various currency pools we manage. The maturities of these investments may from time to time extend beyond 90 days. The types of financial instruments in which we currently invest include:

Time Deposits: Interest bearing deposits placed with approved financial institutions.

Commercial Paper: Unsecured promissory notes issued by a corporation, commercial bank, or government agency purchased at a discount to mature at par.

Government or government agency obligations: Negotiable debt obligations issued by a government or government agency.

These financial instruments appear in the Cash and cash equivalents line of our consolidated balance sheet if the maturities at the time we made the investments were 90 days or less; otherwise, these held-to-maturity investments are included in the Short-term investments line. At December 31, 2010, we held the following financial instruments:

		Millions of Dollars Carrying Amount	
		Cash & Cash Equivalents	Short-Term Investments*
Cash	$	1,284	-
Time Deposits			
Remaining maturities from 1 to 90 days		6,154	302
Remaining maturities from 91 to 180 days		-	69
Commercial Paper			
Remaining maturities from 1 to 90 days		1,566	525
Remaining maturities from 91 to 180 days		-	-
Government Obligations			
Remaining maturities from 1 to 90 days		450	77
Remaining maturities from 91 to 180 days		-	-
	$	9,454	973

**Carrying value approximates fair value.*

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 cash-flow 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 with fixed minimum notional volumes 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 eligible for and we elect the normal purchases and normal sales exception (i.e., contracts to purchase or sell quantities we expect to use or sell over a reasonable period in the normal course of business). 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 sales 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 sales 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 sales 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. A contract that is initially classified as Level 3 due to absence or insufficient corroboration of broker quotes over a material portion of the contract will transfer to Level 2 when the portion of the trade having no quotes or insufficient corroboration becomes an insignificant portion of the contract. A contract would also transfer to Level 2 if we began using a corroborated broker quote that has become available. Conversely, if a corroborated broker quote ceases to be available or used by us, the contract would transfer from Level 2 to Level 3. There were no transfers in or out of 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, 2010				December 31, 2009			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Commodity derivatives	**$ 1,957**	**1,243**	**63**	**3,263**	1,710	1,659	61	3,430
Interest rate derivatives	**-**	**20**	**-**	**20**	-	-	-	-
Foreign currency exchange derivatives	**-**	**15**	**-**	**15**	-	45	-	45
Total assets	**1,957**	**1,278**	**63**	**3,298**	1,710	1,704	61	3,475
Liabilities								
Commodity derivatives	**2,230**	**1,118**	**36**	**3,384**	1,797	1,496	24	3,317
Foreign currency exchange derivatives	**-**	**9**	**-**	**9**	-	47	-	47
Total liabilities	**2,230**	**1,127**	**36**	**3,393**	1,797	1,543	24	3,364
Net assets (liabilities)	**$ (273)**	**151**	**27**	**(95)**	(87)	161	37	111

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.

As reflected in the table above, Level 3 activity is not material.

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Commodity Derivative Contracts We operate in the worldwide crude oil, bitumen, refined product, natural gas, LNG, 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. We also use the market knowledge gained from these activities to capture market opportunities such as moving physical commodities to more profitable locations, storing commodities to capture seasonal or time premiums, and blending commodities to capture quality upgrades. Derivatives may be used to optimize these activities which may move our risk profile away from market average prices.

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

		Millions of Dollars	
		2010	2009
Assets			
Prepaid expenses and other current assets	**$**	**3,073**	3,084
Other assets		**211**	359
Liabilities			
Other accruals		**3,212**	3,006
Other liabilities and deferred credits		**193**	324

Hedge accounting has not been used for any items in the table. 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, and the line items where they appear on our consolidated statement of operations were:

		Millions of Dollars	
		2010	2009
Sales and other operating revenues	**$**	**(1,154)**	1,964
Other income		**(38)**	19
Purchased crude oil, natural gas and products		**1,036**	(2,624)

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

The table below summarizes our material net exposures 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)	
	2010	2009
Commodity		
Crude oil, refined products and natural gas liquids (millions of barrels)	**(16)**	(16)

Natural gas and power (billions of cubic feet equivalent)		
Fixed price	**(69)**	(60)
Basis	**(43)**	154

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Interest Rate Derivative Contracts During the second quarter of 2010, we executed interest rate swaps to synthetically convert $500 million of our 4.60% fixed-rate notes due in 2015 to a London Interbank Offered Rate (LIBOR)-based floating rate. These swaps qualify for and are designated as fair-value hedges using the short-cut method of hedge accounting. The short-cut method permits the assumption that changes in the value of the derivative perfectly offset changes in the value of the debt; therefore, no gain or loss has been recognized due to hedge ineffectiveness.

The fair value of interest rate derivative assets and liabilities and the line items where they appear on our consolidated balance sheet were:

		Millions of Dollars	
		2010	2009
Assets			
Prepaid expenses and other current assets	$	**11**	-
Other assets		**9**	-

Hedge accounting was used for all items in the table. The amounts shown are presented gross.

The (gains) and losses from interest rate derivatives used in a fair-value hedge, losses and (gains) from changes in the fair value of the hedged debt, and the line item where they appear on our consolidated statement of operations were:

		Millions of Dollars	
		2010	2009
Recorded in interest and debt expense			
From the interest rate derivatives	$	**(23)**	-
From the hedged debt		**16**	-

Hedge accounting was used for all items in the table. The amounts shown are presented gross.

The extent to which the change in value of the interest rate derivatives differs from the change in value of the hedged debt is an adjustment to recorded interest expense on the fixed-rate debt that effectively results in interest expense for the period being recorded at floating-rate LIBOR plus the swap spread.

Foreign Currency Exchange Derivatives 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 exchange derivative assets and liabilities, and the line items where they appear on our consolidated balance sheet were:

		Millions of Dollars	
		2010	2009
Assets			
Prepaid expenses and other current assets	$	**14**	38
Other assets		**1**	7
Liabilities			
Other accruals		**7**	40
Other liabilities and deferred credits		**2**	7

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

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Gains and losses from foreign currency exchange derivatives and the line item where they appear on our consolidated statement of operations were:

		Millions of Dollars	
		2010	2009
Foreign currency transaction (gains) losses	$	**118**	(121)

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

We had the following net notional position of outstanding foreign currency exchange derivatives:

		In Millions Notional Currency*	
		2010	2009
Foreign Currency Exchange Derivatives			
Sell U.S. dollar, buy other currencies**	USD	**569**	3,211
Sell Euro, buy British pound	EUR	**253**	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, OTC derivative contracts and trade receivables. Our cash equivalents and short-term investments are placed in high-quality commercial paper, money market funds, government debt securities and time deposits with major international banks and financial institutions.

The credit risk from our OTC derivative contracts, such as forwards and swaps, derives from the counterparty to the transaction. 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 IntercontinentalExchange (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, 2010, was $225 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, 2010, 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 $225 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, cash equivalents, and short-term investments: 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 1.87 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.

Commodity 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.

Interest rate swap contracts: Fair value is estimated based on a pricing model and market observable interest rate swap curves obtained from a third-party market data provider.

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.

Our commodity derivative and financial instruments were:

	Millions of Dollars			
	Carrying Amount		Fair Value	
	2010	2009	**2010**	2009
Financial assets				
Foreign currency exchange derivatives	$ **15**	45	**15**	45
Interest rate derivatives	**20**	-	**20**	-
Commodity derivatives	**624**	823	**624**	823
Investment in LUKOIL*	**1,083**	-	**1,083**	-
Financial liabilities				
Total debt, excluding capital leases	**23,553**	28,622	**26,144**	30,565
Joint venture acquisition obligation	**5,009**	5,669	**5,600**	6,276
Foreign currency exchange derivatives	**9**	47	**9**	47
Commodity derivatives	**426**	632	**426**	632

**Prior to September 30, 2010, our investment in LUKOIL was accounted for using the equity method. See Note 6 Investments, Loans and Long-Term Receivables, for more information.*

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 2010 commodity derivative assets and liabilities appear net of $5 million of obligations to return cash collateral and $324 million of rights to reclaim cash collateral, respectively. 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. No collateral was deposited or held for the foreign currency exchange 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		
	2010	2009	2008
Issued			
Beginning of year	**1,733,345,558**	1,729,264,859	1,718,448,829
Distributed under benefit plans	**7,183,721**	4,080,699	10,816,030
End of year	**1,740,529,279**	1,733,345,558	1,729,264,859
Held in Treasury			
Beginning of year	**208,346,815**	208,346,815	104,607,149
Repurchase of common stock	**64,526,722**	-	103,739,666
End of year	**272,873,537**	208,346,815	208,346,815
Held in Grantor Trusts			
Beginning of year	**38,742,261**	40,739,129	42,411,331
Distributed under benefit plans	**(1,776,873)**	(2,018,692)	(1,668,456)
Repurchase of common stock	**-**	-	(13,600)
Other	**(75,013)**	21,824	9,854
End of year	**36,890,375**	38,742,261	40,739,129

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, 2010 or 2009.

Noncontrolling Interests

At December 31, 2010 and 2009, we had outstanding $547 million and $590 million, respectively, of equity in less-than-wholly owned consolidated subsidiaries held by noncontrolling interest owners. The noncontrolling interest amounts are primarily related to operating joint ventures we control. The largest of these, amounting to $520 million at December 31, 2010, and $565 million at December 31, 2009, 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.

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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, 2010, future minimum rental payments due under noncancelable leases were:

	Millions of Dollars
2011	$ 752
2012	573
2013	460
2014	309
2015	245
Remaining years	557
Total	2,896
Less income from subleases	(140)*
Net minimum operating lease payments	$ 2,756

**Includes $72 million related to railcars subleased to CPChem, a related party.*

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

	Millions of Dollars		
	2010	2009	2008
Total rentals*	**$ 925**	1,024	1,033
Less sublease rentals	**(34)**	(34)	(125)
	$ 891	990	908

**Includes $22 million, $21 million and $22 million of contingent rentals in 2010, 2009 and 2008, respectively. Contingent rentals primarily are related to production and refining equipment, and are based on throughput or volume of product sold.*

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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	
		2010		2009		**2010**	2009
		U.S.	**Int l.**	U.S.	Int l.		
Change in Benefit Obligation							
Benefit obligation at January 1	$	**5,042**	**3,101**	4,620	2,307	**839**	768
Service cost		**229**	**90**	194	79	**11**	9
Interest cost		**260**	**169**	277	144	**46**	47
Plan participant contributions		**-**	**4**	-	8	**20**	22
Medicare Part D subsidy		**-**	**-**	-	-	**-**	1
Plan amendments		**12**	**-**	-	-	**-**	-
Actuarial loss		**305**	**59**	456	366	**14**	63
Benefits paid		**(309)**	**(115)**	(505)	(103)	**(70)**	(75)
Curtailment		**-**	**(1)**	-	-	**-**	-
Recognition of termination benefits		**-**	**-**	-	5	**-**	-
Foreign currency exchange rate change		**-**	**(101)**	-	295	**2**	4
Benefit obligation at December 31*	$	**5,539**	**3,206**	5,042	3,101	**862**	839
**Accumulated benefit obligation portion of above at December 31:*	*$*	***4,905***	***2,711***	*4,359*	*2,595*		
Change in Fair Value of Plan Assets							
Fair value of plan assets at January 1	$	**3,144**	**2,281**	2,373	1,728	**-**	2
Actual return on plan assets		**458**	**259**	574	245	**-**	-
Company contributions		**597**	**216**	702	159	**50**	50
Plan participant contributions		**-**	**4**	-	8	**20**	22
Medicare Part D subsidy		**-**	**-**	-	-	**-**	1
Benefits paid		**(309)**	**(115)**	(505)	(103)	**(70)**	(75)
Curtailment		**-**	**(1)**	-	-	**-**	-
Foreign currency exchange rate change		**-**	**(63)**	-	244	**-**	-
Fair value of plan assets at December 31	$	**3,890**	**2,581**	3,144	2,281	**-**	-
Funded Status	$	**(1,649)**	**(625)**	(1,898)	(820)	**(862)**	(839)

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	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2010		2009		**2010**	2009
	U.S.	**Int l.**	U.S.	Int l.		
Amounts Recognized in the Consolidated Balance Sheet at December 31						
Noncurrent assets	$ **-**	**156**	-	96	**-**	-
Current liabilities	**(74)**	**(4)**	(6)	(12)	**(51)**	(60)
Noncurrent liabilities	**(1,575)**	**(777)**	(1,892)	(904)	**(811)**	(779)
Total recognized	$ **(1,649)**	**(625)**	(1,898)	(820)	**(862)**	(839)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**4.65%**	**5.40**	5.35	5.80	**5.00**	5.60
Rate of compensation increase	**4.00**	**4.10**	4.00	4.50	**-**	-
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount rate	**5.35%**	**5.80**	6.25	6.00	**5.60**	6.30
Expected return on plan assets	**7.00**	**6.50**	7.00	6.60	**-**	7.00
Rate of compensation increase	**4.00**	**4.50**	4.00	4.20	**-**	-

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.

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	
	2010		2009		**2010**	2009
	U.S.	**Int l.**	U.S.	Int l.		
Unrecognized net actuarial loss (gain)	$ **1,567**	**444**	1,664	574	**(51)**	(72)
Unrecognized prior service cost	**61**	**(25)**	58	(24)	**(54)**	(51)

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		Millions of Dollars					
		Pension Benefits				Other Benefits	
		2010		2009		**2010**	2009
		U.S.	**Int l.**	U.S.	Int l.		
Sources of Change in Other Comprehensive Income							
Net gain (loss) arising during the period	$	**(70)**	**75**	(52)	(274)	**(14)**	(62)
Amortization of (gain) loss included in income		**167**	**55**	186	35	**(7)**	(15)
Net gain (loss) during the period	$	**97**	**130**	134	(239)	**(21)**	(77)
Prior service cost arising during the period	$	**(12)**	**(1)**	-	1	**-**	(1)
Amortization of prior service cost included in income		**10**	**2**	11	1	**3**	9
Net prior service cost during the period	$	**(2)**	**1**	11	2	**3**	8

Amounts included in accumulated other comprehensive income at December 31, 2010, that are expected to be amortized into net periodic postretirement cost during 2011 are provided below:

		Millions of Dollars		
		Pension Benefits		Other Benefits
		U.S.	Int l.	
Unrecognized net actuarial loss (gain)	$	165	44	(5)
Unrecognized prior service cost		9	-	(7)

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 $7,661 million, $6,718 million, and $5,706 million, respectively, at December 31, 2010, and $7,145 million, $5,653 million, and $4,748 million, respectively, at December 31, 2009.

For our unfunded nonqualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $479 million and $407 million, respectively, at December 31, 2010, and were $419 million and $355 million, respectively, at December 31, 2009.

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	
2010		2009		2008		**2010**	2009	2008
U.S.	**Int l.**	U.S.	Int l.	U.S.	Int l.			

Components of Net Periodic Benefit Cost									
Service cost	$ **229**	**90**	194	79	186	85	**11**	9	11
Interest cost	**260**	**169**	277	144	247	170	**46**	47	47
Expected return on plan assets	**(224)**	**(147)**	(184)	(125)	(223)	(170)	**-**	-	-
Amortization of prior service cost	**10**	**2**	11	1	10	1	**3**	9	11
Recognized net actuarial loss (gain)	**167**	**55**	186	35	64	17	**(7)**	(15)	(17)
Net periodic benefit cost	$ **442**	**169**	484	134	284	103	**53**	50	52

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We recognized pension settlement losses of $15 million and $18 million and special termination benefits of $5 million and $2 million in 2009 and 2008, respectively. None were recognized in 2010.

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 percent in 2011 that declines to 5 percent by 2023. A one-percentage-point change in the assumed health care cost trend rate would have the following effects on the 2010 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	2	(2)

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, 6 percent real estate and 3 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, 2010 and 2009.

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

Fair values of corporate debt securities, agency and 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 and 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.

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.

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Fair values of exchange-traded derivatives classified in Level 1 are based on quoted market prices. For other derivatives classified in Level 2, the values are generally calculated from pricing models with market input parameters from third-party sources.

Private equity funds are valued at net asset value as determined by the issuer based on the fair value of the underlying assets.

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, 2010, the participating interest in the annuity contract was valued at $92 million and consisted of $357 million in debt securities, less $265 million for the accumulated benefit obligation covered by the contract. 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. The net change from 2009 to 2010 is due to an increase in the fair market value of the underlying investments of $8 million and an increase in the present value of the contract obligation of $10 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.

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

	Millions of Dollars							
	U.S.				International			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
2010								
Equity Securities								
U.S.	$ **1,250**	**-**	**-**	**1,250**	**378**	**-**	**-**	**378**
International	**818**	**-**	**-**	**818**	**498**	**-**	**-**	**498**
Common/collective trusts	**-**	**635**	**-**	**635**	**-**	**246**	**-**	**246**
Mutual funds	**-**	**-**	**-**	**-**	**282**	**-**	**-**	**282**
Debt Securities								
Government	**251**	**56**	**-**	**307**	**390**	**-**	**-**	**390**
Corporate	**-**	**420**	**3**	**423**	**-**	**171**	**2**	**173**
Agency and mortgage-backed securities	**-**	**81**	**-**	**81**	**-**	**-**	**-**	**-**
Common/collective trusts	**-**	**270**	**-**	**270**	**-**	**329**	**-**	**329**
Mutual funds	**-**	**-**	**-**	**-**	**122**	**-**	**-**	**122**
Cash and cash equivalents	**-**	**-**	**-**	**-**	**9**	**10**	**-**	**19**
Private equity funds	**-**	**-**	**6**	**6**	**-**	**-**	**8**	**8**
Derivatives	**-**	**-**	**-**	**-**	**-**	**12**	**-**	**12**
Insurance contacts	**-**	**-**	**-**	**-**	**-**	**-**	**16**	**16**
Real estate	**-**	**-**	**-**	**-**	**-**	**-**	**101**	**101**
Total*	$ **2,319**	**1,462**	**9**	**3,790**	**1,679**	**768**	**127**	**2,574**

**Excludes the participating interest in the annuity contract with a net asset value of $92 million and net receivables related to security transactions of $15 million.*

	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
2009								
Equity Securities								
U.S.	$ 1,021	-	-	1,021	56	-	-	56
International	571	-	-	571	240	-	-	240
Common/collective trusts	-	556	-	556	-	545	-	545
Mutual funds	-	-	-	-	293	-	-	293
Debt Securities								
Government	120	48	-	168	222	-	-	222
Corporate	-	327	3	330	-	341	3	344
Agency and mortgage-backed securities	-	83	-	83	-	24	-	24
Common/collective trusts	-	332	-	332	-	280	-	280
Mutual funds	-	-	-	-	139	-	-	139
Cash and cash equivalents	3	-	-	3	20	11	-	31
Private equity funds	-	-	9	9	-	-	3	3
Derivatives	-	-	-	-	-	12	-	12
Insurance contacts	-	-	-	-	-	-	16	16
Real estate	-	-	-	-	-	-	67	67

Total*	$ 1,715	1,346	12	3,073	970	1,213	89	2,272

**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.*

As reflected in the table above, Level 3 activity is not material.

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 2011, we expect to contribute approximately $730 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		Other Benefits
	U.S.	Int l.	
2011	$ 464	95	55
2012	417	100	57
2013	498	107	59
2014	474	115	62
2015	517	123	63
2016-2020	2,811	719	339

Defined Contribution Plans

Most U.S. employees are eligible to participate in the ConocoPhillips Savings Plan (CPSP). Employees can deposit up to 75 percent of their eligible pay up to the statutory limit ($16,500 in 2010) in the thrift feature of the CPSP to a choice of approximately 39 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 $24 million in 2010, $23 million in 2009, and $28 million in 2008.

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 2011 through 2014, 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 $92 million, $83 million and $111 million in 2010, 2009 and 2008, respectively, all of which was compensation expense. In 2010, 2009 and 2008, we contributed 1,776,873 shares, 2,018,692 shares and 1,668,456 shares, respectively, of company common stock from the Compensation and Benefits Trust. The shares had a fair market value of $103 million, $94 million and $120 million, respectively. Dividends used to service debt were $41 million, $39 million and $41 million in 2010, 2009 and 2008, respectively. These dividends reduced the amount of compensation expense recognized each period. Interest incurred on the CPSP debt in 2010, 2009 and 2008 was $2 million, $2 million and $6 million, respectively.

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

	2010	2009
Unallocated shares	**3,385,778**	5,364,887
Allocated shares	**19,198,502**	19,008,169
Total shares	**22,584,280**	24,373,056

The fair value of unallocated shares at December 31, 2010 and 2009, was $231 million and $274 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 $52 million in 2010, $51 million in 2009 and $53 million in 2008.

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 ASC 718 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 ASC 718 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 ASC 718, 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 years ended December 31, were as follows:

		Millions of Dollars		
		2010	2009	2008
Compensation cost	**$**	**211**	121	193
Tax benefit		**78**	42	67

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, 2010:

	Options		Weighted-Average Exercise Price		Weighted-Average Grant-Date Fair Value		Millions of Dollars Aggregate Intrinsic Value
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				
Granted	**3,040,500**		**48.39**	**$**	**11.70**		
Exercised	**(6,401,483)**		**29.08**			**$**	**183**
Forfeited	**(255,889)**		**48.42**				
Expired or canceled	**(204,727)**		**58.94**				
Outstanding at December 31, 2010	**32,611,874**	**$**	**39.54**				
Vested at December 31, 2010	**30,421,177**	**$**	**38.45**			**$**	**906**

Exercisable at December 31, 2010	**27,252,683**	**$**	**37.39**	**$**	**837**

The weighted-average remaining contractual term of vested options and exercisable options at December 31, 2010, was 3.56 years and 2.98 years, respectively.

During 2010, we received $168 million in cash and realized a tax benefit of $54 million from the exercise of options.

At December 31, 2010, the remaining unrecognized compensation expense from unvested options was $15 million, which will be recognized over a weighted-average period of 17 months, the longest period being 25 months.

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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:

	2010	2009	2008
Assumptions used			
Risk-free interest rate	**3.23%**	2.90	3.21
Dividend yield	**4.00%**	3.50	2.50
Volatility factor	**33.80%**	32.90	27.78
Expected life (years)	**6.65**	6.53	5.82

The ranges in the assumptions used were as follows:

	2010		2009		2008	
	High	**Low**	High	Low	High	Low
Ranges used						
Risk-free interest rate	**3.23%**	**3.23**	2.90	2.90	3.45	2.27
Dividend yield	**4.00**	**4.00**	3.50	3.50	2.50	2.50
Volatility factor	**33.80**	**33.80**	32.90	32.90	32.10	26.70

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, 2010:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
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	
Granted	**2,890,010**		**46.38**	
Forfeited	**(233,212)**		**53.11**	
Issued	**(1,573,487)**			**$ 79**
Outstanding at December 31, 2010	**7,802,863**	**$**	**53.04**	
Not Vested at December 31, 2010	**5,810,124**	**$**	**52.97**	

At December 31, 2010, the remaining unrecognized compensation cost from the unvested units was $165 million, which will be recognized over a weighted-average period of 25 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 2010, 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 2010, 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, 2010:

	Performance Share Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
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	
Granted	**317,072**	**48.39**	
Forfeited	**(53,243)**	**62.66**	
Issued	**(234,121)**		**$ 12**
Outstanding at December 31, 2010	**3,434,586**	**$ 63.43**	
Not Vested at December 31, 2010	**1,075,496**	**$ 35.17**	

At December 31, 2010, the remaining unrecognized compensation cost from unvested Performance Share awards was $38 million, which will be recognized over a weighted-average period of 42 months, the longest period being 16 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.

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The following summarizes the aggregate activity of these restricted shares and units for the three years ended December 31, 2010:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
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	
Granted	**73,395**	**53.33**	
Issued	**(181,035)**		**$ 9**
Canceled	**(58,441)**	**44.23**	
Outstanding at December 31, 2010	**2,970,436**	**$ 34.06**	
Not Vested at December 31, 2010	**114,860**	**$ 79.38**	

At December 31, 2010, the remaining unrecognized compensation cost from the unvested units was $0.3 million, which was recognized by February 2011.

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 2010 and 2009, shares transferred out of the CBT were 1,776,873 and 2,018,692, respectively. At December 31, 2010, the CBT had 36.7 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.

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Note 20 Income Taxes

Income taxes charged to income (loss) were:

	Millions of Dollars		
	2010	2009	2008
Income Taxes			
Federal			
Current	$ **1,312**	575	3,245
Deferred	**781**	52	(227)
Foreign			
Current	**7,469**	5,584	10,268
Deferred*	**(1,546)**	(1,245)	(298)
State and local			
Current	**320**	82	543
Deferred	**(3)**	42	(112)
	$ **8,333**	5,090	13,419

**2009 and 2008 recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information.*

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	
	2010	2009
Deferred Tax Liabilities		
Properties, plants and equipment, and intangibles	$ **20,344**	21,281
Investment in joint ventures	**2,201**	2,039
Inventory	**43**	13
Partnership income deferral	**434**	660
Other*	**586**	807
Total deferred tax liabilities*	**23,608**	24,800
Deferred Tax Assets		
Benefit plan accruals	**1,691**	1,802
Asset retirement obligations and accrued environmental costs	**3,971**	3,874
Deferred state income tax	**257**	251
Other financial accruals and deferrals	**394**	465
Loss and credit carryforwards	**1,344**	2,105
Other	**717**	484
Total deferred tax assets	**8,374**	8,981
Less valuation allowance	**(1,400)**	(1,540)
Net deferred tax assets	**6,974**	7,441
Net deferred tax liabilities*	$ **16,634**	17,359

**2009 recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information.*

Current assets, long-term assets, current liabilities and long-term liabilities included deferred taxes of $562 million, $160 million, $21 million and $17,335 million, respectively, at December 31, 2010, and $581 million, $21 million, $5 million and $17,956 million, respectively, at December 31, 2009.

We have loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2011 and 2030 with some carryovers having indefinite carryforward periods.

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Valuation allowances have been established to reduce deferred tax assets to an amount that will, more likely than not, be realized. During 2010, valuation allowances decreased a total of $140 million. This reflects decreases of $554 million primarily related to utilization of U.S. foreign tax credit and foreign loss carryforwards, partially offset by increases of $414 million, primarily related to foreign tax loss carryforwards and unrealized foreign exchange losses. 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, 2010 and 2009, income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $4,134 million and $2,129 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 2010, 2009 and 2008:

	Millions of Dollars		
	2010	2009	2008
Balance at January 1	$ **1,208**	1,068	1,143
Additions based on tax positions related to the current year	**63**	18	7
Additions for tax positions of prior years	**344**	177	186
Reductions for tax positions of prior years	**(199)**	(33)	(249)
Settlements	**(215)**	(19)	(16)
Lapse of statute	**(76)**	(3)	(3)
Balance at December 31	$ **1,125**	1,208	1,068

Included in the balance of unrecognized tax benefits for 2010, 2009 and 2008 were $914 million, $931 million and $862 million, respectively, which, if recognized, would affect our effective tax rate.

At December 31, 2010, 2009 and 2008, accrued liabilities for interest and penalties totaled $171 million, $166 million and $147 million, respectively, net of accrued income taxes. Interest and penalties benefitted earnings in 2010 by $2 million, and resulted in a charge to earnings in 2009 and 2008 of $18 million and $25 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 (2005), United States (2006) 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.

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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		
	2010	2009*	2008*	**2010**	2009*	2008*
Income (loss) before income taxes						
United States	**$ 6,214**	2,456	10,055	**31.5%**	25.6	(351.6)
Foreign	**13,536**	7,126	12,528	**68.5**	74.4	(438.0)
Goodwill impairment	**-**	-	(25,443)	**-**	-	889.6
	$ 19,750	9,582	(2,860)	**100.0%**	100.0	100.0
Federal statutory income tax	**$ 6,912**	3,354	(1,001)	**35.0%**	35.0	35.0
Goodwill impairment	**-**	-	8,905	**-**	-	(311.4)
Foreign taxes in excess of federal statutory rate	**1,308**	1,716	5,452	**6.6**	17.9	(190.6)
Federal manufacturing deduction	**(82)**	(19)	(182)	**(0.4)**	(0.2)	6.4
State income tax	**206**	81	280	**1.0**	0.8	(9.8)
Other	**(11)**	(42)	(35)	**-**	(0.4)	1.2
	$ 8,333	5,090	13,419	**42.2%**	53.1	(469.2)

**Recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information.*

The change in the effective tax rate from 2009 was primarily due to the effect of asset dispositions in 2010 and a higher proportion of income in higher tax jurisdictions in 2009, offset in part by the effect of asset impairments occurring in 2010.

Statutory tax rate changes did not have a significant impact on our income tax expense in 2010, 2009 or 2008.

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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
2010			
Defined benefit pension plans:			
Prior service cost arising during the year	**$ (13)**	**(4)**	**(9)**
Reclassification adjustment for amortization of prior service cost included in net income	**15**	**6**	**9**
Net prior service cost	**2**	**2**	**-**
Net loss arising during the year	**(9)**	**(7)**	**(2)**
Reclassification adjustment for amortization of prior net losses included in net income	**215**	**80**	**135**
Net actuarial gain	**206**	**73**	**133**
Nonsponsored plans*	**5**	**(8)**	**13**
Unrealized holding gain arising during the year	**631**	**228**	**403**
Reclassification adjustment for gain included in net income	**(384)**	**(139)**	**(245)**
Net unrealized gain on securities**	**247**	**89**	**158**
Foreign currency translation adjustments	**1,417**	**13**	**1,404**
Other comprehensive income	**$ 1,877**	**169**	**1,708**
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)

**Plans for which ConocoPhillips is not the primary obligor primarily those administered by equity affiliates.*
***Available-for-sale securities of LUKOIL.*

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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 in the equity section of the balance sheet included:

	Millions of Dollars	
	2010	2009
Defined benefit pension liability adjustments	**$ (1,358)**	(1,504)
Net unrealized gain on securities	**158**	-
Foreign currency translation adjustments	**5,980**	4,576
Deferred net hedging loss	**(7)**	(7)
Accumulated other comprehensive income	**$ 4,773**	3,065

Note 22 Cash Flow Information

	Millions of Dollars		
	2010	2009	2008
Noncash Investing and Financing Activities			
Increase in PP&E related to an increase in asset retirement obligations	**$ 808**	974	1,117
Cash Payments			
Interest	**$ 1,210**	998	858
Income taxes	**8,474**	6,641	13,122

Note 23 Other Financial Information

		Millions of Dollars Except Per Share Amounts	
	2010	2009	2008
Interest and Debt Expense			
Incurred			
Debt	$ **1,414**	1,485	1,189
Other	**244**	291	314
	1,658	1,776	1,503
Capitalized	**(471)**	(487)	(568)
Expensed	$ **1,187**	1,289	935
Other Income			
Interest income	$ **187**	227	245
Other, net	**91**	131	(46)
	$ **278**	358	199
Research and Development Expenditures expensed	$ **230**	190	209
Advertising Expenses	$ **66**	60	96
Shipping and Handling Costs*	$ **1,366**	1,185	1,443

**Amounts included in production and operating expenses.*

Cash Dividends paid per common share	$ **2.15**	1.91	1.88
Foreign Currency Transaction (Gains) Losses after-tax			
E&P	$ **(60)**	111	(216)
Midstream	**-**	-	(1)
R&M	**60**	(36)	173
LUKOIL Investment	**15**	(20)	27
Chemicals	**-**	-	-
Emerging Businesses	**1**	(2)	7
Corporate and Other	**15**	(97)	72
	$ **31**	(44)	62

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Note 24 Related Party Transactions

Significant transactions with related parties were:

		Millions of Dollars		
		2010	2009	2008
Operating revenues and other income (a)	$	**7,333**	7,200	13,097
Gain on dispositions (b)		**1,149**	-	-
Purchases (c)		**15,819**	12,779	19,409
Operating expenses and selling, general and administrative expenses (d)		**344**	322	515
Net interest expense (e)		**73**	74	66

(a) We sold natural gas to DCP Midstream 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 CPChem, gas oil and hydrogen feedstocks were sold to Excel Paralubes and refined products were sold primarily to CFJ Properties and LUKOIL. Beginning in the third quarter of 2010, CFJ was no longer considered a related party due to the sale of our interest. Natural gas, crude oil, blendstock and other intermediate products were sold to WRB Refining LP. In addition, we charged several of our affiliates, including CPChem and MSLP, for the use of common facilities, such as steam generators, waste and water treaters, and warehouse facilities.

(b) During 2010, we sold a portion of our LUKOIL shares under a stock purchase and option agreement with a wholly owned subsidiary of LUKOIL, resulting in a before-tax gain of $1,149 million.

(c) 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 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.

(d) We paid processing fees to various affiliates. Additionally, we paid transportation fees to pipeline equity companies.

(e) 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.

Beginning in the fourth quarter of 2010, transactions with LUKOIL and its subsidiaries were no longer considered related party transactions. See Note 6 Investments, Loans and Long-Term Receivables, for additional information.

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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, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2010, 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, Qatar 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, 2010, 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, 2010, our ownership interest was 2.25 percent based on issued shares. See Note 6 Investments, Loans and Long-Term Receivables, for information on sales of LUKOIL shares.

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 CPChem.

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, 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 and short-term investments.

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		
	2010	2009	2008
Sales and Other Operating Revenues			
E&P*			
United States	$ **28,934**	24,287	51,378
International	**27,992**	24,222	36,972
Intersegment eliminations U.S.	**(5,653)**	(4,649)	(8,034)
Intersegment eliminations international	**(7,748)**	(6,763)	(10,498)
E&P	**43,525**	37,097	69,818
Midstream			
Total sales	**7,714**	5,199	6,791
Intersegment eliminations	**(407)**	(307)	(227)
Midstream	**7,307**	4,892	6,564
R&M*			
United States	**94,564**	73,871	117,727
International	**44,721**	34,025	47,520
Intersegment eliminations U.S.	**(763)**	(613)	(965)
Intersegment eliminations international	**(101)**	(50)	(52)
R&M	**138,421**	107,233	164,230
LUKOIL Investment	**-**	-	-
Chemicals	**11**	11	11
Emerging Businesses			
Total sales	**746**	593	1,060
Intersegment eliminations	**(595)**	(507)	(861)
Emerging Businesses	**151**	86	199
Corporate and Other	**26**	22	20
Consolidated sales and other operating revenues	$ **189,441**	149,341	240,842

**2010 includes $20,344 million in our E&P and R&M segments which resulted from transactions with a single, external customer.*

Depreciation, Depletion, Amortization and Impairments			
E&P			
United States	$ **2,909**	3,346	3,725
International	**5,268**	5,459	5,096
Goodwill impairment	**-**	-	25,443

Total E&P	**8,177**	8,805	34,264
Midstream	**6**	6	6
R&M			
United States	**711**	707	1,129
International	**1,789**	215	425
Total R&M	**2,500**	922	1,554
LUKOIL Investment*	**-**	-	7,496
Chemicals	**-**	-	-
Emerging Businesses	**78**	21	193
Corporate and Other	**79**	76	124
Consolidated depreciation, depletion, amortization and impairments	**$ 10,840**	9,830	43,637

**2009 and 2008 recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information.*

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	Millions of Dollars		
	2010	2009	2008
Equity in Earnings of Affiliates			
E&P			
United States	**$ 39**	(2)	57
International	**(14)**	233	235
Total E&P	**25**	231	292
Midstream	**411**	342	810
R&M			
United States	**607**	428	836
International	**113**	13	178
Total R&M	**720**	441	1,014
LUKOIL Investment*	**1,295**	1,219	2,760(1)
Chemicals	**684**	298	128
Emerging Businesses	**(2)**	-	(5)
Corporate and Other	**-**	-	-
Consolidated equity in earnings of affiliates	**$ 3,133**	2,531	4,999

(1) Does not include a $7,496 million impairment of our LUKOIL investment which is presented as a separate line item in the consolidated statement of operations.

Income Taxes			
E&P			
United States	**$ 1,570**	786	2,617
International	**6,124**	4,325	9,621
Total E&P	**7,694**	5,111	12,238
Midstream	**158**	171	261
R&M			
United States	**645**	32	934
International	**(414)**	9	214
Total R&M	**231**	41	1,148
LUKOIL Investment*	**514**	12	63
Chemicals	**182**	47	15
Emerging Businesses	**(54)**	(16)	(6)
Corporate and Other	**(392)**	(276)	(300)
Consolidated income taxes	**$ 8,333**	5,090	13,419

Net Income (Loss) Attributable to ConocoPhillips			
E&P			
United States	**$ 2,768**	1,503	4,988
International	**6,430**	2,101	6,976
Goodwill impairment	**-**	-	(25,443)
Total E&P	**9,198**	3,604	(13,479)
Midstream	**306**	313	541
R&M			
United States	**1,022**	(192)	1,540
International	**(830)**	229	782
Total R&M	**192**	37	2,322
LUKOIL Investment*	**2,503**	1,219	(4,839)
Chemicals	**498**	248	110
Emerging Businesses	**(59)**	3	30
Corporate and Other	**(1,280)**	(1,010)	(1,034)
Consolidated net income (loss) attributable to ConocoPhillips	**$ 11,358**	4,414	(16,349)

**2009 and 2008 recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information.*

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	Millions of Dollars		
	2010	2009	2008
Investments In and Advances To Affiliates			
E&P			
United States	**$ 1,989**	1,978	1,368
International	**21,049**	19,646	16,772
Total E&P	**23,038**	21,624	18,140
Midstream	**1,240**	1,199	1,033
R&M			
United States	**4,059**	3,982	3,677
International	**1,304**	1,142	1,326
Total R&M	**5,363**	5,124	5,003
LUKOIL Investment*	**-**	6,411	5,452
Chemicals	**2,518**	2,446	2,186
Emerging Businesses	**76**	77	75
Corporate and Other	**-**	-	-
Consolidated investments in and advances to affiliates(1)	**$ 32,235**	36,881	31,889
(1) Includes amounts classified as held for sale:	*$ -*	*249*	*2*
Total Assets			
E&P			
United States	**$ 35,607**	36,122	36,962
International	**63,086**	64,831	58,912
Total E&P	**98,693**	100,953	95,874
Midstream	**2,506**	2,054	1,455
R&M			
United States	**26,028**	24,963	22,554
International	**8,463**	8,446	7,942
Goodwill	**3,633**	3,638	3,778
Total R&M	**38,124**	37,047	34,274
LUKOIL Investment*	**1,129**	6,416	5,455
Chemicals	**2,732**	2,451	2,217
Emerging Businesses	**964**	1,069	924
Corporate and Other	**12,166**	2,148	2,666
Consolidated total assets	**$ 156,314**	152,138	142,865

Capital Expenditures and Investments			
E&P			
United States	**$ 2,585**	3,474	5,250
International	**5,908**	5,425	11,206
Total E&P	**8,493**	8,899	16,456
Midstream	**3**	5	4
R&M			
United States	**790**	1,299	1,643
International	**266**	427	626
Total R&M	**1,056**	1,726	2,269
LUKOIL Investment	**-**	-	-
Chemicals	**-**	-	-
Emerging Businesses	**27**	97	156
Corporate and Other	**182**	134	214
Consolidated capital expenditures and investments	**$ 9,761**	10,861	19,099

**2009 and 2008 recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information.*

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	Millions of Dollars		
	2010	2009	2008
Interest Income and Expense			
Interest income			
Corporate	$ **64**	89	128
E&P	**81**	91	115
R&M	**42**	47	2
Interest and debt expense			
Corporate	$ **1,047**	1,133	762
E&P	**140**	156	173

Geographic Information

	Millions of Dollars					
	Sales and Other Operating Revenues(1)			Long-Lived Assets(2)		
	2010	2009	2008	**2010**	2009	2008
United States	$ **124,173**	97,674	166,496	**53,706**	53,761	52,972
Australia(3)	**2,789**	2,229	2,735	**12,461**	10,729	8,656
Canada	**4,784**	3,617	5,226	**20,439**	22,451	20,429
Norway	**2,248**	1,749	3,036	**5,664**	5,797	5,002
Russia(4)	**-**	-	-	**815**	8,383	7,604
United Kingdom	**26,693**	20,671	29,699	**4,885**	5,778	5,844
Other foreign countries	**28,754**	23,401	33,650	**16,819**	17,441	15,919
Worldwide consolidated	$ **189,441**	149,341	240,842	**114,789**	124,340	116,426

(1)Sales and other operating revenues are attributable to countries based on the location of the operations generating the revenues.

(2)Defined as net properties, plants and equipment plus investments in and advances to affiliated companies.

(3)Includes amounts related to the joint petroleum development area with shared ownership held by Australia and Timor-Leste.

(4)2009 and 2008 recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, for more information.

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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.

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, 2010, approximately 12 percent of our total proved reserves 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.

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 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, the synthetic oil classification includes Syncrude mining operations, and the bitumen classification includes our Surmont operations and the FCCL Partnership. In June 2010, we sold our interest in the Syncrude Canada Ltd. joint venture; accordingly, as of December 31, 2010, we no longer held synthetic oil reserves.

Two items occurred during 2010 that impact the disclosure of our investment in OAO LUKOIL in the supplemental oil and gas disclosures:

- Effective January 1, 2010, we changed the method used to determine our equity-method share of LUKOIL s earnings. Prior to 2010, we estimated our LUKOIL equity earnings for the current quarter. Beginning in 2010, we implemented a change in accounting principle to record our LUKOIL equity earnings on a one-quarter-lag basis. Prior periods have been recast to reflect this change, including those in the supplemental oil and gas disclosures (other than the proved reserves tables, which continue to reflect LUKOIL on a current basis).

- On July 28, 2010, we announced our intention to sell our entire interest in LUKOIL over a period of time through the end of 2011. As a result of this sell down of our interest, at the end of the third quarter of 2010 we ceased using equity-method accounting for our investment in LUKOIL. Accordingly, the supplemental oil and gas disclosures reflect activity for LUKOIL through June 30, 2010, which, on a lag basis, results in three quarters of activity being included in the year 2010 (the fourth quarter of 2009 and the first two quarters of 2010). Since the proved reserves tables are not on a lag basis, they reflect activity for the first three quarters of 2010, at which point LUKOIL s reserves were removed from our reserve quantities.

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See Note 2 Changes in Accounting Principles, and Note 6 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for more information about both of these items.

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 Manager of Reserves Compliance and Reporting. 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.

During 2010, our processes and controls used to assess over 90 percent of proved reserves as of December 31, 2010, were reviewed by DeGolyer and MacNaughton (D&M), a third-party petroleum engineering consulting firm. The purpose of their review was to assess whether the adequacy and effectiveness of our internal processes and controls used to determine estimates of proved reserves are in accordance with SEC regulations. In such review, ConocoPhillips technical staff presented D&M with an overview of the reserves data, as well as the methods and assumptions used in estimating reserves. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, reservoir simulation models, well performance data, operating procedures and relevant economic criteria. Management s intent in retaining D&M to review its processes and controls was to provide objective third-party input on these processes and controls. D&M s opinion was that the general processes and controls employed by ConocoPhillips in estimating its December 31, 2010, proved reserves for the properties reviewed are in accordance with the SEC reserves definitions. D&M s report is included as Exhibit 99 of this Annual Report on Form 10-K.

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	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 and Undeveloped										
Consolidated operations										
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
Revisions	81	8	89	15	28	-	7	21	-	160
Improved recovery	51	2	53	-	-	-	5	-	-	58
Purchases	-	1	1	-	-	-	-	-	-	1
Extensions and discoveries	17	30	47	4	18	-	7	10	-	86
Production	(84)	(55)	(139)	(14)	(78)	-	(51)	(28)	-	(310)
Sales	-	(22)	(22)	(6)	-	-	-	-	-	(28)
End of 2010	1,285	649	1,934	80	469	-	300	270	108	3,161
Equity affiliates										
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
Revisions	-	-	-	-	-	6	51	-	-	57
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(114)	(1)	-	-	(115)
Sales	-	-	-	-	-	(1,421)	-	-	-	(1,421)
End of 2010	-	-	-	-	-	75	156	-	-	231
Total company										
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
End of 2010	1,285	649	1,934	80	469	75	456	270	108	3,392

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 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
End of 2010	1,155	534	1,689	75	290	-	218	251	-	2,523
Equity affiliates										
End of 2007	-	-	-	-	-	1,354	-	-	-	1,354
End of 2008	-	-	-	-	-	1,228	-	-	-	1,228
End of 2009	-	-	-	-	-	1,213	-	-	-	1,213
End of 2010	-	-	-	-	-	73	156	-	-	229
Undeveloped										
Consolidated operations										
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
End of 2010	130	115	245	5	179	-	82	19	108	638
Equity affiliates										
End of 2007	-	-	-	-	-	371	109	-	-	480
End of 2008	-	-	-	-	-	340	109	-	-	449
End of 2009	-	-	-	-	-	391	106	-	-	497
End of 2010	-	-	-	-	-	2	-	-	-	2

Notable changes in proved crude oil and natural gas liquids reserves in the three years ended December 31, 2010, 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.

Sales: In 2010 for our equity affiliates in Russia, sales were primarily due to the disposition of our interest in LUKOIL.

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 and Undeveloped										
Consolidated operations										
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
Revisions	155	365	520	309	86	-	(39)	36	-	912
Improved recovery	24	1	25	-	-	-	-	-	-	25
Purchases	-	9	9	-	-	-	-	-	-	9
Extensions and discoveries	4	122	126	84	89	-	24	-	-	323
Production	(101)	(663)	(764)	(358)	(323)	-	(289)	(60)	-	(1,794)
Sales	-	(179)	(179)	(26)	-	-	-	-	-	(205)
End of 2010	2,862	7,617	10,479	2,305	1,861	-	2,608	926	56	18,235
Equity affiliates										
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
Revisions	-	-	-	-	-	19	683	-	-	702
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	269	-	-	269
Production	-	-	-	-	-	(91)	(65)	-	-	(156)
Sales	-	-	-	-	-	(2,616)	-	-	-	(2,616)
End of 2010	-	-	-	-	-	17	3,464	-	-	3,481
Total company										
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
End of 2010	2,862	7,617	10,479	2,305	1,861	17	6,072	926	56	21,716

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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 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
End of 2010	2,785	6,399	9,184	2,134	1,529	-	2,136	865	-	15,848
Equity affiliates										
End of 2007	-	-	-	-	-	698	-	-	-	698
End of 2008	-	-	-	-	-	1,458	361	-	-	1,819
End of 2009	-	-	-	-	-	1,506	307	-	-	1,813
End of 2010	-	-	-	-	-	17	3,114	-	-	3,131
Undeveloped										
Consolidated operations										
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
End of 2010	77	1,218	1,295	171	332	-	472	61	56	2,387
Equity affiliates										
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
End of 2010	-	-	-	-	-	-	350	-	-	350

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, 2010, included:

Revisions: In 2010, revisions in Alaska, Lower 48 and Canada were primarily due to higher prices in 2010, versus 2009, as well as improved well performance. 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 2010, extensions and discoveries in Lower 48 and Canada were primarily due to continued drilling success in various fields. 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.

Sales: In 2010, for our equity affiliates in Russia, sales were primarily due to the disposition of our interest in LUKOIL.

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Years Ended December 31	Other Products Millions of Barrels	
	Synthetic Oil Canada	**Bitumen** Canada
Developed and Undeveloped		
Consolidated operations		
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
Revisions	-	42
Improved recovery	-	-
Purchases	-	-
Extensions and discoveries	-	-
Production	(4)	(4)
Sales	(244)	-
End of 2010	-	455
Equity affiliates		
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
Revisions	-	13
Improved recovery	-	-
Purchases	-	-
Extensions and discoveries	-	133
Production	-	(18)
Sales	-	-
End of 2010	-	844
Total company		
End of 2007	-	708
End of 2008	-	800
End of 2009	248	1,133
End of 2010	-	1,299

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Years Ended December 31	Other Products Millions of Barrels	
	Synthetic Oil Canada	**Bitumen** Canada
Developed		
Consolidated operations		
End of 2007	-	17
End of 2008	-	24
End of 2009	248	24
End of 2010	-	34
Equity affiliates		
End of 2007	-	45
End of 2008	-	105
End of 2009	-	116
End of 2010	-	142
Undeveloped		
Consolidated operations		
End of 2007	-	68
End of 2008	-	76
End of 2009	-	393
End of 2010	-	421
Equity affiliates		
End of 2007	-	578
End of 2008	-	595
End of 2009	-	600
End of 2010	-	702

Notable changes in proved synthetic oil and bitumen reserves in the three years ended December 31, 2010, 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.

Extensions and Discoveries: In 2009, for our bitumen consolidated operations, extensions and discoveries were related to the sanction of the Surmont Phase II Project. In 2010 and 2009, for our equity affiliate operations, extensions and discoveries mainly reflect the continued development of FCCL.

Sales: In 2010, for synthetic oil consolidated operations, sales reflect the disposition of our interest in Syncrude.

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 and Undeveloped										
Consolidated operations										
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
Revisions	107	68	175	109	42	-	1	27	-	354
Improved recovery	55	2	57	-	-	-	5	-	-	62
Purchases	-	2	2	-	-	-	-	-	-	2
Extensions and discoveries	17	51	68	18	33	-	11	10	-	140
Production	(101)	(165)	(266)	(82)	(132)	-	(99)	(38)	-	(617)
Sales	-	(52)	(52)	(254)	-	-	-	-	-	(306)
End of 2010	1,762	1,918	3,680	920	779	-	735	424	117	6,655
Equity affiliates										
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
Revisions	-	-	-	13	-	9	165	-	-	187
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	133	-	-	45	-	-	178
Production	-	-	-	(18)	-	(129)	(12)	-	-	(159)
Sales	-	-	-	-	-	(1,857)*	-	-	-	(1,857)
End of 2010	-	-	-	844	-	78	733	-	-	1,655
Total company										
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
End of 2010	1,762	1,918	3,680	1,764	779	78	1,468	424	117	8,310

**Includes 594 million barrels of oil equivalent due to the cessation of equity accounting.*

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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 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
End of 2010	1,619	1,601	3,220	465	545	-	574	396	-	5,200
Equity affiliates										
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
End of 2010	-	-	-	142	-	76	675	-	-	893
Undeveloped										
Consolidated operations										
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
End of 2010	143	317	460	455	234	-	161	28	117	1,455
Equity affiliates										
End of 2007	-	-	-	578	-	424	430	-	-	1,432
End of 2008	-	-	-	595	-	475	469	-	-	1,539
End of 2009	-	-	-	600	-	591	484	-	-	1,675
End of 2010	-	-	-	702	-	2	58	-	-	762

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

We had 2,217 million BOE of proved undeveloped reserves at year-end 2010, compared with 3,087 million BOE at year-end 2009. The disposition of our investment in LUKOIL resulted in the removal of 589 million BOE of undeveloped reserves. We also converted 844 million BOE of undeveloped reserves to developed during 2010 as we achieved startup of major development projects. Finally, we added 563 million BOE of undeveloped reserves in 2010 mainly through exploratory success and revisions. As a result, at December 31, 2010, our proved undeveloped reserves represented 27 percent of total proved reserves, compared with 30 percent at December 31, 2009. Costs incurred for the year ended December 31, 2010, relating to the development of proved undeveloped reserves were $3.3 billion.

Approximately 75 percent of our proved undeveloped reserves at year-end 2010 were associated with eight major development areas. Seven of the major development areas are currently producing and are expected to have proved undeveloped reserves convert 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 major project, the Kashagan Field in Kazakhstan, will have proved undeveloped reserves convert to developed as this project begins production.

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At the end of 2010, 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 2010 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.

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Results of Operations

Year Ended December 31, 2010		Millions of Dollars									
		Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Consolidated operations											
Sales	$	3,645	3,600	7,245	2,379	5,967	-	4,958	1,743	-	22,292
Transfers		2,693	2,389	5,082	246	2,278	-	770	450	-	8,826
Other revenues		-	559	559	3,216	142	-	55	172	18	4,162
Total revenues		6,338	6,548	12,886	5,841	8,387	-	5,783	2,365	18	35,280
Production costs excluding taxes		849	1,230	2,079	873	1,004	-	538	296	-	4,790
Taxes other than income taxes		1,570	498	2,068	74	6	1	355	18	1	2,523
Exploration expenses		37	292	329	295	146	2	260	29	101	1,162
Depreciation, depletion and amortization		529	2,231	2,760	1,666	1,972	2	1,206	202	-	7,808
Impairments		4	19	23	13	43	-	-	-	-	79
Transportation costs		528	424	952	134	281	-	119	23	-	1,509
Other related expenses		(38)	112	74	41	42	17	(48)	(10)	62	178
Accretion		58	55	113	50	192	-	24	-	4	383
		2,801	1,687	4,488	2,695	4,701	(22)	3,329	1,807	(150)	16,848
Provision for income taxes		1,014	555	1,569	108	3,066	(23)	1,361	1,458	(28)	7,511
Results of operations for producing activities		1,787	1,132	2,919	2,587	1,635	1	1,968	349	(122)	9,337
Other earnings		(52)	(99)	(151)	(72)	76	16	139	29	8	45
Net income (loss) attributable to ConocoPhillips	$	1,735	1,033	2,768	2,515	1,711	17	2,107	378	(114)	9,382
Equity affiliates											
Sales	$	-	-	-	955	-	5,189	249	-	-	6,393
Transfers		-	-	-	-	-	1,876	-	-	-	1,876
Other revenues		-	-	-	7	-	1,219	10	-	-	1,236
Total revenues		-	-	-	962	-	8,284	259	-	-	9,505
		-	-	-	265	-	544	59	-	-	868

Production costs excluding taxes											
Taxes other than income taxes		-	-	-	4	-	3,463	42	-	-	3,509
Exploration expenses		-	-	-	-	-	61	(2)	-	-	59
Depreciation, depletion and amortization		-	-	-	190	-	568	55	-	-	813
Impairments		-	-	-	-	-	645	-	-	-	645
Transportation costs		-	-	-	-	-	784	25	-	-	809
Other related expenses		-	-	-	(3)	-	-	44	-	-	41
Accretion		-	-	-	2	-	7	2	-	-	11
		-	-	-	504	-	2,212	34	-	-	2,750
Provision for income taxes		-	-	-	128	-	647	(25)	-	-	750
Results of operations for producing activities		-	-	-	376	-	1,565	59	-	-	2,000
Other earnings		-	-	-	-	-	405	(86)	-	-	319
Net income (loss) attributable to ConocoPhillips	$	-	-	-	376	-	1,970	(27)	-	-	2,319

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Year Ended December 31, 2009		Millions of Dollars									
		Alaska*	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Consolidated operations											
Sales	$	3,353	3,144	6,497	2,179	4,995	-	3,830	1,562	11	19,074
Transfers		2,261	1,937	4,198	345	2,305	-	500	257	-	7,605
Other revenues		30	54	84	168	(66)	-	10	136	54	386
Total revenues		5,644	5,135	10,779	2,692	7,234	-	4,340	1,955	65	27,065
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		251	60	311	(3)	62	3	121	23	14	531
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	-	3,783	74	-	-	4,570
Transfers		-	-	-	-	-	1,946	-	-	-	1,946
Other revenues		-	-	-	(2)	-	-	1	-	-	(1)
Total revenues		-	-	-	711	-	5,729	75	-	-	6,515
Production costs excluding taxes		-	-	-	213	-	501	26	-	-	740

Taxes other than income taxes		-	-	-	3	-	2,270	4	-	-	2,277
Exploration expenses		-	-	-	-	-	37	2	-	-	39
Depreciation, depletion and amortization		-	-	-	133	-	455	21	-	-	609
Impairments**		-	-	-	-	-	83	-	-	-	83
Transportation costs		-	-	-	-	-	703	3	-	-	706
Other related expenses		-	-	-	17	-	3	1	-	-	21
Accretion		-	-	-	1	-	6	1	-	-	8
		-	-	-	344	-	1,671	17	-	-	2,032
Provision for income taxes		-	-	-	89	-	326	9	-	-	424
Results of operations for producing activities		-	-	-	255	-	1,345	8	-	-	1,608
Other earnings**		-	-	-	-	-	(201)	(86)	-	-	(287)
Net income (loss) attributable to ConocoPhillips	$	-	-	-	255	-	1,144	(78)	-	-	1,321

**Certain amounts were reclassified between Sales and Transfers, as well as between Other revenues and Other related expenses. Total Results of operations was unchanged.*
***Goodwill considered to be a non-oil-and-gas producing activity was reclassified from Impairments to Other earnings.*

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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	-	6,890	9	-	-	7,543
Transfers		-	-	-	-	-	4,660	-	-	-	4,660
Other revenues		-	-	-	45	-	-	-	-	-	45
Total revenues		-	-	-	689	-	11,550	9	-	-	12,248
		-	-	-	182	-	730	4	-	-	916

Production costs excluding taxes											
Taxes other than income taxes		-	-	-	3	-	5,725	-	-	-	5,728
Exploration expenses		-	-	-	-	-	87	-	-	-	87
Depreciation, depletion and amortization		-	-	-	84	-	550	9	-	-	643
Impairments		-	-	-	-	-	7,038	-	-	-	7,038
Transportation costs		-	-	-	-	-	910	1	-	-	911
Other related expenses		-	-	-	1	-	7	5	-	-	13
Accretion		-	-	-	1	-	5	-	-	-	6
		-	-	-	418	-	(3,502)	(10)	-	-	(3,094)
Provision for income taxes		-	-	-	132	-	1,070	(11)	-	1	1,192
Results of operations for producing activities		-	-	-	286	-	(4,572)	1	-	(1)	(4,286)
Other earnings		-	-	-	3	-	(410)	(3)	-	-	(410)
Net income (loss) attributable to ConocoPhillips	$	-	-	-	289	-	(4,982)	(2)	-	(1)	(4,696)

**Excludes goodwill impairment of $25,443 million.*

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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.

The equity affiliate results in Russia for 2009 reflect only three quarters of activity for our share of LUKOIL. Under the lag accounting method used for our investment in LUKOIL, equity earnings were not recorded in the first quarter of 2009, since our LUKOIL investment was written down in the fourth quarter of 2008 to its fair value at December 31, 2008. This approach was consistently followed in Results of Operations (RESOP), such that LUKOIL s fourth-quarter 2008 results are not reflected in RESOP. For supplemental information, the fourth-quarter 2008 amounts excluded for selected line items were: total revenues $1,371 million; production costs $171 million; taxes other than income taxes $867 million; and DD&A $127 million. These amounts were included in the numerator of the per-unit calculations included in the Statistics section.

Statistics

Net Production	**2010**	2009	2008
	Thousands of Barrels Daily		
Crude Oil and Natural Gas Liquids			
Consolidated operations			
Alaska	**230**	252	261
Lower 48	**160**	166	165
United States	**390**	418	426
Canada	**38**	40	44
Europe	**211**	241	233
Asia Pacific/Middle East	**140**	132	107
Africa	**79**	78	80
Other areas	**-**	4	9
Total consolidated operations	**858**	913	899
Equity affiliates			
Russia	**336**	443	413
Asia Pacific/Middle East	**3**	-	-
Total equity affiliates	**339**	443	413
Total company	**1,197**	1,356	1,312
Synthetic Oil			
Consolidated operations Canada	**12**	23	22
Bitumen			
Consolidated operations Canada	**10**	7	6
Equity affiliates Canada	**49**	43	30
Total company	**59**	50	36
	Millions of Cubic Feet Daily		
Natural Gas*			
Consolidated operations			
Alaska	**82**	94	97
Lower 48	**1,695**	1,927	1,994
United States	**1,777**	2,021	2,091
Canada	**984**	1,062	1,054
Europe	**815**	876	954
Asia Pacific/Middle East	**712**	713	609

Africa	**149**	121	114
Other areas	**-**	-	14
Total consolidated operations	**4,437**	4,793	4,836
Equity affiliates			
Russia	**254**	295	330
Asia Pacific/Middle East	**169**	84	11
Total equity affiliates	**423**	379	341
Total company	**4,860**	5,172	5,177

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

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Average Sales Prices	**2010**	2009	2008
Crude Oil and Natural Gas Liquids Per Barrel			
Consolidated operations			
Alaska	$ **78.61**	59.23	99.10
Lower 48	**57.69**	44.12	74.70
United States	**69.73**	53.21	89.38
Canada	**55.70**	41.76	76.53
Europe	**77.35**	58.92	92.10
Asia Pacific/Middle East	**75.50**	57.59	87.32
Africa	**76.80**	60.83	91.54
Other areas	**-**	32.01	84.74
Total international	**74.95**	57.40	89.32
Total consolidated operations	**72.63**	55.47	89.35
Equity affiliates			
Russia	**56.65**	43.19	75.90
Asia Pacific/Middle East	**83.82**	-	-
Total equity affiliates	**56.87**	43.19	75.90
Synthetic Oil Per Barrel			
Consolidated operations Canada	$ **77.56**	62.01	103.31
Bitumen Per Barrel			
Consolidated operations Canada	$ **51.10**	39.67	46.85
Equity affiliates Canada	**53.43**	45.69	58.54
Natural Gas Per Thousand Cubic Feet*			
Consolidated operations			
Alaska	$ **4.62**	5.33	5.36
Lower 48	**4.25**	3.42	7.71
United States	**4.27**	3.50	7.60
Canada	**3.74**	3.33	7.92
Europe	**6.94**	6.81	10.55
Asia Pacific/Middle East	**7.39**	6.00	8.45
Africa	**1.81**	1.56	1.09
Other areas	**-**	-	1.41
Total international	**5.60**	5.06	8.65
Total consolidated operations	**5.07**	4.40	8.20
Equity affiliates			
Russia	**1.18**	1.16	1.04
Asia Pacific/Middle East	**2.79**	2.35	2.04
Total equity affiliates	**1.82**	1.43	1.07

**Prior periods reclassified to conform to current year presentation of including intrasegment transfer pricing.*

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		2010	2009	2008
Average Production Costs Per Barrel of Oil Equivalent*				
Consolidated operations				
Alaska	$	**9.55**	8.84	9.46
Lower 48		**7.62**	7.12	7.72
United States		**8.30**	7.73	8.34
Canada		**10.68**	11.21	10.74
Europe		**7.93**	7.42	8.06
Asia Pacific/Middle East		**5.70**	4.86	5.61
Africa		**7.81**	7.54	6.76
Other areas		**-**	5.48	8.20
Total international		**7.96**	7.72	8.03
Total consolidated operations		**8.10**	7.73	8.17
Equity affiliates				
Canada		**14.82**	13.57	16.58
Russia		**3.94**	3.74	4.26
Asia Pacific/Middle East		**5.19**	5.09	5.96
Total equity affiliates		**5.19**	4.54	5.01
Average Production Costs Per Barrel Bitumen				
Consolidated operations Canada	$	**19.45**	30.92	39.62
Equity affiliates Canada		**14.82**	13.57	16.58
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent*				
Consolidated operations				
Alaska	$	**17.65**	11.62	33.83
Lower 48		**3.08**	2.37	4.20
United States		**8.26**	5.65	14.80
Canada		**.91**	.83	.74
Europe		**.05**	.02	.20
Asia Pacific/Middle East		**3.76**	1.80	3.87
Africa		**.47**	.47	.75
Other areas		**-**	4.79	49.42
Total international		**1.34**	.74	1.81
Total consolidated operations		**4.27**	2.87	7.69
Equity affiliates				
Canada		**.22**	.19	.27
Russia		**25.08**	17.46	33.42
Asia Pacific/Middle East		**3.69**	.78	-
Total equity affiliates		**20.97**	15.69	31.31

Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent*

Consolidated operations			
Alaska	$ **5.95**	6.25	5.51
Lower 48	**13.81**	14.71	13.33
United States	**11.02**	11.71	10.53
Canada	**20.38**	18.73	21.82
Europe	**15.58**	14.27	13.36
Asia Pacific/Middle East	**12.77**	9.94	9.61
Africa	**5.33**	5.61	5.93
Other areas	**-**	7.53	5.79
Total international	**14.82**	13.40	13.69
Total consolidated operations	**13.21**	12.67	12.26
Equity affiliates			
Canada	**10.62**	8.47	7.65
Russia	**4.11**	3.24	3.21
Asia Pacific/Middle East	**4.83**	4.11	13.41
Total equity affiliates	**4.86**	3.67	3.51

**Includes bitumen. For 2008, excludes our Canadian synthetic oil operations.*

Net Wells Completed[1]	Productive			Dry		
	2010	2009	2008	**2010**	2009	2008
Exploratory[2]						
Consolidated operations						
Alaska	**-**	-	-	**-**	2	1
Lower 48	**23**	33	81	**1**	14	22
United States	**23**	33	81	**1**	16	23
Canada	**15**	17	49	**7**	19	36
Europe	**1**	1	*	*****	2	1
Asia Pacific/Middle East	**3**	3	1	**1**	3	*
Africa	**1**	*	*	*****	*	1
Other areas	**-**	-	-	**-**	-	1
Total consolidated operations	**43**	54	131	**9**	40	62
Equity affiliates						
Russia	**-**	1	1	**-**	-	1
Asia Pacific/Middle East	**2**	-	-	**-**	-	*
Total equity affiliates[3]	**2**	1	1	**-**	-	1
Includes step-out wells of:	***23***	*40*	*127*	***1***	*29*	*27*

	Productive			Dry		
	2010	2009	2008	**2010**	2009	2008
Development						
Consolidated operations						
Alaska	**47**	47	47	*****	-	-
Lower 48	**269**	592	690	**2**	4	8
United States	**316**	639	737	**2**	4	8
Canada	**186**	227	465	**12**	20	32
Europe	**6**	9	10	**-**	-	-
Asia Pacific/Middle East	**59**	47	26	*****	-	-
Africa	**9**	3	4	**-**	-	-
Other areas	**-**	-	-	**-**	-	-
Total consolidated operations	**576**	925	1,242	**14**	24	40
Equity affiliates						
Canada	**112**	61	148	**-**	-	-
Russia	**2**	6	7	**-**	*	-
Asia Pacific/Middle East	**25**	28	*	**-**	-	-
Total equity affiliates[3]	**139**	95	155	**-**	*	-

(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 December 31, 2010			Productive(2)			
	In Progress(1)		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
Consolidated operations						
Alaska	24	13	1,886	849	32	21
Lower 48	276	185	12,599	4,606	25,081	15,990
United States	300	198	14,485	5,455	25,113	16,011
Canada	228*(3)*	166*(3)*	1,647	995	12,875	7,646
Europe	31	6	611	109	273	111
Asia Pacific/Middle East	79	33	466	199	107	49
Africa	93	16	1,131	196	11	2
Other areas	38	3	-	-	-	-
Total consolidated operations	769	422	18,340	6,954	38,379	23,819
Equity affiliates						
Canada	15	8	202	101	-	-
Russia	7	2	107	38	2	1
Asia Pacific/Middle East	753	205	-	-	569	174
Total equity affiliates	775	215	309	139	571	175

(1)Includes wells that have been temporarily suspended.
(2)Includes 6,000 gross and 3,802 net multiple completion wells.
(3)Includes 191 gross and 138 net stratigraphic test wells for heavy oil projects.

Acreage at December 31, 2010	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Consolidated operations				
Alaska	647	328	1,720	1,361
Lower 48	5,932	5,304	10,323	8,859
United States	6,579	5,632	12,043	10,220
Canada	6,958	4,464	6,970	4,581
Europe	868	242	3,271	1,393
Asia Pacific/Middle East	4,123	1,777	20,052	12,646
Africa	528	132	14,729	2,575
Other areas	-	-	14,646	9,522
Total consolidated operations	19,056	12,247	71,711	40,937
Equity affiliates				
Canada	33	14	518	209
Russia	291	90	1,173	476

Asia Pacific/Middle East	1,108	288	8,823	3,570
Total equity affiliates	1,432	392	10,514	4,255

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Costs Incurred

Years Ended December 31	Millions of Dollars										
		Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
2010											
Consolidated operations											
Unproved property acquisition	$	(26)	286	260	113	9	-	-	-	-	382
Proved property acquisition		-	100	100	1	-	-	-	-	-	101
		(26)	386	360	114	9	-	-	-	-	483
Exploration		119	487	606	269	144	3	356	45	143	1,566
Development		588	1,439	2,027	927	1,351	-	858	375	729	6,267
	$	681	2,312	2,993	1,310	1,504	3	1,214	420	872	8,316
Equity affiliates											
Unproved property acquisition	$	-	-	-	81	-	15	-	-	-	96
Proved property acquisition		-	-	-	-	-	173	379	-	-	552
		-	-	-	81	-	188	379	-	-	648
Exploration		-	-	-	-	-	92	123	-	-	215
Development		-	-	-	621	-	751	403	-	-	1,775
	$	-	-	-	702	-	1,031	905	-	-	2,638
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	$	-	-	-	-	-	18	-	-	-	18
Proved property acquisition		-	-	-	-	-	176	219	-	-	395
		-	-	-	-	-	194	219	-	-	413
Exploration		-	-	-	-	-	62	53	-	-	115
Development		-	-	-	446	-	820	376	-	-	1,642
	$	-	-	-	446	-	1,076	648	-	-	2,170

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Years Ended December 31		Millions of Dollars									
		Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
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	$	-	-	-	-	-	35	4,505	-	-	4,540
Proved property acquisition		-	-	-	7	-	144	245	-	-	396
		-	-	-	7	-	179	4,750	-	-	4,936
Exploration		-	-	-	-	-	134	5	-	-	139
Development		-	-	-	569	-	1,767	214	-	-	2,550
	$	-	-	-	576	-	2,080	4,969	-	-	7,625

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.

Exploration costs include geological and geophysical expenses, the cost of retaining undeveloped leaseholds, exploratory drilling costs, and costs incurred to assess the commerciality of potential discoveries.

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

At December 31		Millions of Dollars									
		Alaska	Lower 48	Total U.S.	Canada	Europe	Russia*	Asia Pacific/ Middle East	Africa	Other Areas	Total
2010											
Consolidated operations											
Proved properties	$	12,268	32,076	44,344	20,037	21,547	9	11,199	3,595	3,921	104,652
Unproved properties		1,471	1,700	3,171	1,930	328	1	1,113	163	249	6,955
		13,739	33,776	47,515	21,967	21,875	10	12,312	3,758	4,170	111,607
Accumulated depreciation, depletion and amortization		5,758	13,362	19,120	10,281	13,636	7	4,690	1,370	10	49,114
	$	7,981	20,414	28,395	11,686	8,239	3	7,622	2,388	4,160	62,493
Equity affiliates											
Proved properties	$	-	-	-	4,812	-	1,923	2,320	-	-	9,055
Unproved properties		-	-	-	1,794	-	146	8,144	-	-	10,084
		-	-	-	6,606	-	2,069	10,464	-	-	19,139
Accumulated depreciation, depletion and amortization		-	-	-	512	-	1,584	84	-	-	2,180
	$	-	-	-	6,094	-	485	10,380	-	-	16,959
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		5,218	13,464	18,682	8,919	11,995	5	3,578	1,167	43	44,389

amortization											
	$	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	-	12,796	1,511	-	-	18,219
Unproved properties		-	-	-	1,681	-	956	6,840	-	-	9,477
		-	-	-	5,593	-	13,752	8,351	-	-	27,696
Accumulated depreciation, depletion and amortization		-	-	-	299	-	9,026	36	-	-	9,361
	$	-	-	-	5,294	-	4,726	8,315	-	-	18,335

**2009 equity affiliates adjusted to reclassify certain costs between proved and unproved, as well as to include amounts determined to be capitalized.*

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.

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

In accordance with SEC and FASB requirements, amounts for 2010 and 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 within the 12-month period prior to the end of the reporting period. Amounts for 2008 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
2010										
Consolidated operations										
Future cash inflows	$ 102,743	68,949	171,692	38,083	49,270	-	37,673	24,487	8,466	329,671
Less:										
Future production and transportation costs*	57,899	29,749	87,648	16,753	12,899	-	10,480	4,142	3,007	134,929
Future development costs	8,792	12,700	21,492	11,161	10,295	-	2,226	1,133	3,050	49,357
Future income tax provisions	13,383	9,024	22,407	2,416	16,765	-	9,211	16,217	384	67,400
Future net cash flows	22,669	17,476	40,145	7,753	9,311	-	15,756	2,995	2,025	77,985
10 percent annual discount	10,723	7,551	18,274	3,890	2,597	-	4,889	1,025	2,368	33,043
Discounted future net cash flows	$ 11,946	9,925	21,871	3,863	6,714	-	10,867	1,970	(343)	44,942
Equity affiliates										
	$ -	-	-	47,169	-	5,610	32,845	-	-	85,624

Future cash inflows											
Less:											
Future production and transportation costs*		-	-	-	16,492	-	4,809	21,036	-	-	42,337
Future development costs		-	-	-	4,684	-	85	295	-	-	5,064
Future income tax provisions		-	-	-	6,649	-	(80)	2,082	-	-	8,651
Future net cash flows		-	-	-	19,344	-	796	9,432	-	-	29,572
10 percent annual discount		-	-	-	13,453	-	293	4,732	-	-	18,478
Discounted future net cash flows	$	-	-	-	5,891	-	503	4,700	-	-	11,094
Total company											
Discounted future net cash flows	$	11,946	9,925	21,871	9,754	6,714	503	15,567	1,970	(343)	56,036

**Includes taxes other than income taxes.*

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	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	19,618	6,416	270,473
Less:										
Future production and transportation costs**	44,789	32,491	77,280	23,625	13,559	-	9,058	3,832	2,071	129,425
Future development costs	7,829	8,350	16,179	12,769	10,369	-	2,284	1,142	3,879	46,622
Future income tax provisions	7,519	2,992	10,511	2,183	10,676	-	7,288	12,396	71	43,125
Future net cash flows	14,222	7,174	21,396	7,388	7,228	-	12,646	2,248	395	51,301
10 percent annual discount	6,474	2,300	8,774	3,703	1,878	-	4,108	879	1,566	20,908
Discounted future net cash flows	$ 7,748	4,874	12,622	3,685	5,350	-	8,538	1,369	(1,171)	30,393
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	1,369	(1,171)	42,274

**Restated to include amounts omitted and to reclassify between production costs, development costs and taxes.*
***Includes taxes other than income taxes.*

	Millions of Dollars									
2008	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa*	Other Areas	Total
Consolidated operations										
Future cash inflows	$ 54,662	51,354	106,016	19,632	42,230	-	22,626	12,478	4,357	207,339
Less:										
Future production and transportation costs**	35,150	30,508	65,658	9,357	12,217	-	6,960	3,229	2,000	99,421
Future development costs	9,681	10,443	20,124	4,188	8,835	-	2,859	800	2,084	38,890
Future income tax provisions	3,227	3,439	6,666	401	11,679	-	4,880	6,919	248	30,793
Future net cash flows	6,604	6,964	13,568	5,686	9,499	-	7,927	1,530	25	38,235
10 percent annual discount	2,159	2,886	5,045	1,222	3,178	-	2,998	541	703	13,687
Discounted future net cash flows	$ 4,445	4,078	8,523	4,464	6,321	-	4,929	989	(678)	24,548
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
	-	-	-	894	-	119	2,281	-	-	3,294

10 percent annual discount											
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	989	(678)	27,581

**Restated to include amounts omitted and to reclassify between production costs, development costs and taxes.*
***Includes taxes other than income taxes.*
Excludes discounted future net cash flows from Canadian Syncrude of $435 million.

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Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars								
	Consolidated Operations			Equity Affiliates			Total Company		
	2010	2009*	2008*	**2010**	2009	2008	**2010**	2009	2008
Discounted future net cash flows at the beginning of the year	**$ 30,393**	24,548	67,162	**11,881**	3,033	20,027	**42,274**	27,581	87,189
Changes during the year									
Revenues less production and transportation costs for the year**	**(22,296)**	(18,460)	(32,149)	**(3,083)**	(2,793)	(4,648)	**(25,379)**	(21,253)	(36,797)
Net change in prices, and production and transportation costs***	**39,532**	19,208	(72,850)	**3,478**	14,386	(20,766)	**43,010**	33,594	(93,616)
Extensions, discoveries and improved recovery, less estimated future costs	**4,517**	2,312	1,759	**297**	1,342	181	**4,814**	3,654	1,940
Development costs for the year	**5,617**	6,148	7,715	**1,758**	1,623	2,622	**7,375**	7,771	10,337
Changes in estimated future development costs	**(3,722)**	(7,036)	(3,270)	**(129)**	(2,197)	(813)	**(3,851)**	(9,233)	(4,083)
Purchases of reserves in place, less estimated future costs	**19**	3	10	**-**	96	321	**19**	99	331
Sales of reserves in place, less estimated future costs	**(3,729)**	(75)	(52)	**(5,405)**	-	(33)	**(9,134)**	(75)	(85)
Revisions of previous quantity estimates**	**3,062**	5,149	1,904	**372**	(1,597)	(1,689)	**3,434**	3,552	215
Accretion of discount	**5,000**	3,972	11,765	**1,404**	365	2,456	**6,404**	4,337	14,221
Net change in income taxes	**(13,451)**	(5,376)	42,554	**521**	(2,377)	5,375	**(12,930)**	(7,753)	47,929
Total changes	**14,549**	5,845	(42,614)	**(787)**	8,848	(16,994)	**13,762**	14,693	(59,608)

Discounted future net cash flows at year end	$ **44,942**	30,393	24,548	**11,094**	11,881	3,033	**56,036**	42,274	27,581

**Restated to include amounts omitted in the Africa geographic area.*
***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 2010 and 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 2008, 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.

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Selected Quarterly Financial Data (Unaudited)

	Millions of Dollars				Per Share of Common Stock Net Income Attributable to ConocoPhillips	
	Sales and Other Operating Revenues*	Income Before Income Taxes	Net Income	Net Income Attributable to ConocoPhillips	Basic	Diluted
2010						
First	**$ 44,821**	**3,990**	**2,112**	**2,098**	**1.41**	**1.40**
Second	**45,686**	**6,194**	**4,183**	**4,164**	**2.79**	**2.77**
Third	**47,208**	**5,274**	**3,069**	**3,055**	**2.06**	**2.05**
Fourth	**51,726**	**4,292**	**2,053**	**2,041**	**1.40**	**1.39**
2009						
First	$ 30,741	1,992	816	800	.54	.54
Second	35,448	1,938	875	859	.58	.57
Third	40,173	2,913	1,487	1,470	.98	.97
Fourth	42,979	2,739	1,314	1,285	.86	.86

**Includes excise taxes on petroleum products sales.*

Certain amounts in 2009 have been recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for more information.

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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. 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.

Certain amounts in 2009 and 2008 have been recast to reflect a change in accounting principle. See Note 2 Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for more information.

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	Millions of Dollars							
	Year Ended December 31, 2010							
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	$ -	116,220	-	-	-	73,221	-	189,441
Equity in earnings of affiliates	11,977	13,433	-	-	-	2,195	(24,472)	3,133
Gain on dispostions	-	388	-	-	-	5,415	-	5,803
Other income (loss)	1	275	-	-	(28)	30	-	278
Intercompany revenues	5	1,394	46	86	66	25,971	(27,568)	-
Total Revenues and Other Income	11,983	131,710	46	86	38	106,832	(52,040)	198,655
Costs and Expenses								
Purchased crude oil, natural gas and products	-	105,105	-	-	-	57,091	(26,445)	135,751
Production and operating expenses	-	4,646	-	-	-	6,087	(98)	10,635
Selling, general and administrative expenses	12	1,392	-	-	-	629	(28)	2,005
Exploration expenses	-	247	-	-	-	908	-	1,155
Depreciation, depletion and amortization	-	1,597	-	-	-	7,463	-	9,060
Impairments	-	51	-	-	-	1,729	-	1,780
Taxes other than income taxes	-	5,157	-	-	-	11,638	(2)	16,793
Accretion on discounted liabilities	-	63	-	-	-	384	-	447
Interest and debt expense	946	475	42	77	45	597	(995)	1,187
Foreign currency transaction (gains) losses	-	20	-	47	50	(25)	-	92
Total Costs and Expenses	958	118,753	42	124	95	86,501	(27,568)	178,905
Income (loss) before income taxes	11,025	12,957	4	(38)	(57)	20,331	(24,472)	19,750
Provision for income taxes	(333)	980	1	7	(6)	7,684	-	8,333
Net income (loss)	11,358	11,977	3	(45)	(51)	12,647	(24,472)	11,417

Less: net income attributable to noncontrolling interests	-	-	-	-	-	(59)	-	(59)
Net Income (Loss) Attributable to ConocoPhillips	$ 11,358	11,977	3	(45)	(51)	12,588	(24,472)	11,358

Statement of Operations	Year Ended December 31, 2009							
Revenues and Other Income								
Sales and other operating revenues	$ -	90,916	-	-	-	58,425	-	149,341
Equity in earnings of affiliates	4,815	5,459	-	-	-	1,666	(9,409)	2,531
Gain on dispositions	-	157	-	-	-	3	-	160
Other income (loss)	-	396	-	-	-	(38)	-	358
Intercompany revenues	30	1,119	51	78	48	18,478	(19,804)	-
Total Revenues and Other Income	4,845	98,047	51	78	48	78,534	(29,213)	152,390
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	4,197	5,030	5	(170)	(221)	10,150	(9,409)	9,582
Provision for income taxes	(217)	215	2	4	(24)	5,110	-	5,090
Net income (loss)	4,414	4,815	3	(174)	(197)	5,040	(9,409)	4,492

Less: net income attributable to noncontrolling interests	-	-	-	-	-	(78)	-	(78)
Net Income (Loss) Attributable to ConocoPhillips	$ 4,414	4,815	3	(174)	(197)	4,962	(9,409)	4,414

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	Millions of Dollars							
	Year Ended December 31, 2008							
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	$ -	153,695	-	-	-	87,147	-	240,842
Equity in earnings of affiliates	(16,140)	(11,424)	-	-	-	4,991	27,572	4,999
Gain (loss) on dispositions	-	(17)	-	-	-	908	-	891
Other income (loss)	(3)	814	-	-	-	(612)	-	199
Intercompany revenues	26	3,390	86	85	52	30,348	(33,987)	-
Total Revenues and Other Income	(16,117)	146,458	86	85	52	122,782	(6,415)	246,931
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	-	-	-	24,762	-	34,625
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)	120,104	(33,987)	249,791
Income (loss) before income taxes	(16,463)	(17,210)	7	262	294	2,678	27,572	(2,860)
Provision for income taxes	(114)	1,301	3	(10)	20	12,219	-	13,419
Net income (loss)	(16,349)	(18,511)	4	272	274	(9,541)	27,572	(16,279)

Less: net income attributable to noncontrolling interests	-	-	-	-	-	(70)	-	(70)
Net Income (Loss) Attributable to ConocoPhillips	$ (16,349)	(18,511)	4	272	274	(9,611)	27,572	(16,349)

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	Millions of Dollars							
	At December 31, 2010							
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
Assets								
Cash and cash equivalents	$ -	718	-	29	4	8,703	-	9,454
Short-term investments	-	-	-	-	-	973	-	973
Accounts and notes receivable	36	9,126	1	-	-	16,625	(9,976)	15,812
Investment in LUKOIL	-	-	-	-	-	1,083	-	1,083
Inventories	-	3,121	-	-	-	2,076	-	5,197
Prepaid expenses and other current assets	23	824	-	2	-	1,292	-	2,141
Total Current Assets	59	13,789	1	31	4	30,752	(9,976)	34,660
Investments, loans and long-term receivables*	84,446	111,993	762	1,445	577	50,563	(216,025)	33,761
Net properties, plants and equipment	-	19,524	-	-	-	63,030	-	82,554
Goodwill	-	3,633	-	-	-	-	-	3,633
Intangibles	-	760	-	-	-	41	-	801
Other assets	55	254	1	3	3	589	-	905
Total Assets	$ 84,560	149,953	764	1,479	584	144,975	(226,001)	156,314
Liabilities and Stockholders Equity								
Accounts payable	$ -	14,939	-	2	-	13,434	(9,976)	18,399
Short-term debt	(5)	354	-	-	-	587	-	936
Accrued income and other taxes	-	431	-	-	6	4,437	-	4,874
Employee benefit obligations	-	773	-	-	-	308	-	1,081
Other accruals	242	620	9	15	6	1,237	-	2,129

Total Current Liabilities	237	17,117	9	17	12	20,003	(9,976)	27,419
Long-term debt	11,832	3,674	750	1,250	499	4,651	-	22,656
Asset retirement obligations and accrued environmental costs	-	1,686	-	-	-	7,513	-	9,199
Joint venture acquisition obligation	-	-	-	-	-	4,314	-	4,314
Deferred income taxes	(1)	3,659	-	16	(2)	13,663	-	17,335
Employee benefit obligations	-	2,779	-	-	-	904	-	3,683
Other liabilities and deferred credits*	10,752	32,268	-	114	61	19,169	(59,765)	2,599
Total Liabilities	22,820	61,183	759	1,397	570	70,217	(69,741)	87,205
Retained earnings	33,897	21,584	3	(94)	(81)	20,162	(35,074)	40,397
Other common stockholders equity	27,843	67,186	2	176	95	54,049	(121,186)	28,165
Noncontrolling interests	-	-	-	-	-	547	-	547
Total Liabilities and Stockholders Equity	$ 84,560	149,953	764	1,479	584	144,975	(226,001)	156,314

**Includes intercompany loans.*

Balance Sheet				At December 31, 2009				
Assets								
Cash and cash equivalents	$ -	122	-	18	1	554	(153)	542
Short-term investments	-	-	-	2,973	-	-	(2,973)	-
Accounts and notes receivable	26	6,495	-	-	-	13,712	(7,018)	13,215
Inventories	-	2,911	-	-	-	2,029	-	4,940
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*	70,769	91,643	759	1,376	933	47,886	(175,272)	38,094
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	$ 70,863	126,492	760	4,374	941	134,234	(185,526)	152,138
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	15,155	-	17,956
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	69,175	(52,680)	89,525
Retained earnings	25,714	9,607	-	(49)	(30)	10,240	(13,268)	32,214
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	$ 70,863	126,492	760	4,374	941	134,234	(185,526)	152,138

**Includes intercompany loans.*

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Millions of Dollars
Year Ended December 31, 2010

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	$ 7,901	2,311	-	11	(3)	9,338	(2,513)	17,045
Cash Flows From Investing Activities								
Capital expenditures and investments	-	(1,863)	-	-	-	(8,221)	323	(9,761)
Proceeds from asset dispositions	-	781	-	-	-	14,690	(99)	15,372
Net purchases of short-term investments	-	-	-	-	-	(982)	-	(982)
Long-term advances/loans related parties	-	(335)	-	-	-	(2,279)	2,301	(313)
Collection of advances/loans related parties	-	107	-	-	384	1,379	(1,755)	115
Other	-	28	-	-	-	206	-	234
Net Cash Provided by (Used in) Investing Activities	-	(1,282)	-	-	384	4,793	770	4,665
Cash Flows From Financing Activities								
Issuance of debt	-	2,159	-	-	-	260	(2,301)	118
Repayment of debt	(990)	(2,660)	-	-	(378)	(3,047)	1,755	(5,320)
Issuance of company common stock	133	-	-	-	-	-	-	133
Repurchase of company common stock	(3,866)	-	-	-	-	-	-	(3,866)
Dividends paid on common stock	(3,175)	-	-	-	-	(2,666)	2,666	(3,175)
Other	(3)	52	-	-	-	(534)	(224)	(709)

Net Cash Provided by (Used in) Financing Activities	(7,901)	(449)	-	-	(378)	(5,987)	1,896	(12,819)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	16	-	-	-	5	-	21
Net Change in Cash and Cash Equivalents	-	596	-	11	3	8,149	153	8,912
Cash and cash equivalents at beginning of year	-	122	-	18	1	554	(153)	542
Cash and Cash Equivalents at End of Year	$ -	718	-	29	4	8,703	-	9,454
Statement of Cash Flows			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

	Millions of Dollars							
	Year Ended December 31, 2008							
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 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

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Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

As of December 31, 2010, 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, 2010.

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, 2010, 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 70 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 72 and is incorporated herein by reference.

Item 9B. OTHER INFORMATION

None.

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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 2011 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2011, 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 2011 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2011, 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 2011 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2011, 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 2011 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2011, 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 2011 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2011, and is incorporated herein by reference.*

**Except for information or data specifically incorporated herein by reference under Items 10 through 14, other information and data appearing in our 2011 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.*

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Schedule

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 69, 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 175 through 178 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, 2011, 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
2010					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	**$ 76**	**(31)**	**(1)**	**(12)(b)**	**32**
Deferred tax asset valuation allowance	**1,540**	**414**	**(12)**	**(542)**	**1,400**
Included in other liabilities:					
Restructuring accruals	**73**	**78**	**1**	**(47)(c)**	**105**
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

(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	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).
10.2	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).
10.3	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).
10.4	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).
10.5	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).

Exhibit Number	Description
10.6	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).
10.7	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).
10.8	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).
10.9	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).
10.10.1	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).
10.10.2	First Amendment to the ConocoPhillips Key Employee Supplemental Retirement Plan.
10.11.1	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).
10.11.2	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).
10.12	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).
10.13	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).
10.14	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).
10.15	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).

10.16 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).

Exhibit Number	Description
10.17.1	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).
10.17.2	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).
10.18.1	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).
10.18.2	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).
10.19	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).
10.20.1	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).
10.20.2	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).
10.20.3	First Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips Title II.
10.20.4	Second Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips Title II.
10.21	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).
10.22	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).
10.23	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).
10.24	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).

10.25	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
10.26	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).
10.27	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).
10.28	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).
10.29	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.
23.1	Consent of Ernst & Young LLP.
23.2	Consent of DeGolyer and MacNaughton.
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.
99	Report of DeGolyer and MacNaughton.
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 23, 2011	/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 23, 2011, 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/ Jeff W. Sheets *Jeff W. Sheets*	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)

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/s/ Richard L. Armitage	Director
Richard L. Armitage	
/s/ Richard H. Auchinleck	Director
Richard H. Auchinleck	
/s/ James E. Copeland, Jr.	Director
James E. Copeland, Jr.	
/s/ Kenneth M. Duberstein	Director
Kenneth M. Duberstein	
/s/ Ruth R. Harkin	Director
Ruth R. Harkin	
/s/ Harold W. McGraw III	Director
Harold W. McGraw III	
/s/ Robert A. Niblock	Director
Robert A. Niblock	
/s/ Harald J. Norvik	Director
Harald J. Norvik	
/s/ William K. Reilly	Director
William K. Reilly	
/s/ Bobby S. Shackouls	Director

Bobby S. Shackouls	
/s/ Victoria J. Tschinkel	Director
Victoria J. Tschinkel	
/s/ Kathryn C. Turner	Director
Kathryn C. Turner	
/s/ William E. Wade, Jr.	Director
William E. Wade, Jr.	

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