CONOCOPHILLIPS
Form 10-K
February 22, 2008

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2007

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, 2007**

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)
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
6.375% Notes due 2009	New York Stock Exchange
6.65% Debentures due July 15, 2018	New York Stock Exchange
7% Debentures due 2029	New York Stock Exchange

7.125% Debentures due March 15, 2028	New York Stock Exchange
9 3/8% 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 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. (Check one):

[x] Large accelerated filer	[ ] 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 29, 2007, the last business day of the registrant s most recently completed second fiscal quarter, based on the closing price on that date of $78.50, was $127.7 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 882,588 and 43,363,722 shares, respectively, in determining the aggregate market value.

The registrant had 1,561,506,369 shares of common stock outstanding at January 31, 2008.

Documents incorporated by reference:

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 14, 2008 (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 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 forecasts, intends, believes, expects, plans, scheduled, targeted, goal, may, anticipates, estimates, and similar expressions identify forward-looking statements. The company does n undertake to update, revise or correct any of the forward-looking information. 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 92.

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. (Conoco) and Phillips Petroleum Company (Phillips). The merger between Conoco and Phillips (the merger) was consummated on August 30, 2002, at which time Conoco and Phillips combined their businesses by merging with separate acquisition subsidiaries of ConocoPhillips.

Our business is organized into six operating segments:

Exploration and Production (E&P) This segment primarily explores for, produces, transports and markets crude oil, natural gas 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, primarily in the United States and Trinidad. The Midstream segment primarily consists of our 50 percent equity investment in DCP Midstream, LLC.

Refining and Marketing (R&M) This segment purchases, refines, markets and transports crude oil and petroleum products, mainly in the United States, Europe and Asia.

LUKOIL Investment This segment consists of our equity investment in the ordinary shares of OAO LUKOIL (LUKOIL), an international, integrated oil and gas company headquartered in Russia. At December 31, 2007, our ownership interest was 20 percent based on issued shares, and 20.6 percent based on estimated shares outstanding.

Chemicals This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists of our 50 percent equity investment in Chevron Phillips Chemical Company LLC (CPChem).

Emerging Businesses This segment represents our investment in new technologies or businesses outside our normal scope of operations.

At December 31, 2007, ConocoPhillips employed approximately 32,600 people.

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SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment and geographic information, see Note 29 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, 2007, our E&P segment represented 68 percent of ConocoPhillips total assets, while contributing 39 percent of net income. The E&P segment contributed 63 percent of net income in 2006. This decrease primarily reflects the impact of a $4,512 million (after-tax) non-cash impairment related to the expropriation of our oil interests in Venezuela. For additional information, see the Expropriated Assets section of Note 13 Impairments, in the Notes to Consolidated Financial Statements.

This segment explores for, produces, transports and markets crude oil, natural gas, and natural gas liquids on a worldwide basis. It also mines deposits of oil sands in Canada to extract the bitumen and upgrade it into a synthetic crude oil. Operations to liquefy and transport natural gas are also included in the E&P segment. At December 31, 2007, our E&P operations were producing in the United States, Norway, the United Kingdom, the Netherlands, Canada, Nigeria, Ecuador, Argentina, offshore Timor-Leste in the Timor Sea, Australia, China, Indonesia, Algeria, Libya, Vietnam, and Russia.

On January 3, 2007, we closed on a business venture with EnCana Corporation to create an integrated North American heavy-oil business. The venture consists of two 50/50 business ventures a Canadian upstream general partnership, FCCL Oil Sands Partnership, and a U.S. downstream limited liability company, WRB Refining LLC.

On March 31, 2006, we completed the acquisition of Burlington Resources Inc., an independent exploration and production company that held a substantial position in North American natural gas proved reserves, production and exploratory acreage.

The E&P segment does not include the financial results or statistics from our equity investment in the ordinary shares of LUKOIL, which are reported in a separate segment (LUKOIL Investment). As a result, references to results, production, prices and other statistics throughout the E&P segment exclude those related to our equity investment in LUKOIL. However, our share of LUKOIL is included in the supplemental oil and gas operations disclosures on pages 174 through 193.

The information listed below appears in the supplemental oil and gas operations disclosures and is incorporated herein by reference:

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

In 2007, E&P s worldwide production, including its share of equity affiliates production other than LUKOIL, averaged 1,857,000 barrels-of-oil-equivalent (BOE) per day, a decrease compared with the 1,936,000 BOE per day averaged in 2006. During 2007, 843,000 BOE per day were produced in the United States, an increase from 808,000 BOE per day in 2006. Production from our international E&P operations averaged 1,014,000 BOE per day in 2007, a decrease compared with 1,128,000 BOE per day in 2006. In addition, our Canadian Syncrude mining operations had net production of 23,000 barrels per day in 2007, compared with 21,000 barrels per day in 2006. The decrease in worldwide production was

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primarily due to expropriation of the company s Venezuelan oil interests, our exit from Dubai, and the effect of asset dispositions. We convert our natural gas production to BOE based on a 6:1 ratio: six thousand cubic feet of natural gas equals one barrel-of-oil-equivalent.

E&P s worldwide annual average crude oil sales price increased 11 percent, from $60.37 per barrel in 2006 to $67.11 per barrel in 2007. E&P s annual average worldwide natural gas sales price increased 1 percent, from $6.19 per thousand cubic feet in 2006 to $6.26 per thousand cubic feet in 2007.

E&P U.S. OPERATIONS

In 2007, U.S. E&P operations contributed 46 percent of E&P s worldwide liquids production and 45 percent of natural gas production, compared with 40 percent and 44 percent in 2006, respectively.

Alaska

Greater Prudhoe Area

The Greater Prudhoe Area is comprised of the Prudhoe Bay field and satellites, as well as the Greater Point McIntyre Area fields. We have a 36.1 percent non-operator interest in all fields within the Greater Prudhoe Area.

The Prudhoe Bay field is the largest oil field on Alaska s North Slope. It 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. Our net crude oil production from the Prudhoe Bay field averaged 82,200 barrels per day in 2007, compared with 78,800 barrels per day in 2006, while natural gas liquids production averaged 17,900 barrels per day in 2007, compared with 16,700 barrels per day in 2006. The operator has undertaken a program to replace 16 miles of oil transit lines in the Prudhoe Bay field, with an expected completion date in the fourth quarter of 2008.

Prudhoe Bay satellite fields, including Aurora, Borealis, Polaris, Midnight Sun, and Orion, produced 11,900 net barrels per day of crude oil in 2007, compared with 12,900 net barrels per day in 2006. All Prudhoe Bay satellite fields produce through the Prudhoe Bay production facilities.

The Greater Point McIntyre Area (GPMA) primarily includes the Point McIntyre, Niakuk, and Lisburne fields. The fields within the GPMA generally produce through the Lisburne Production Center. Net crude oil production for GPMA averaged 12,700 barrels per day in 2007, compared with 11,400 barrels per day in 2006, while natural gas liquids production averaged 760 barrels per day in 2007, compared with 800 barrels per day in 2006. The bulk of GPMA production came from the Point McIntyre field, which is approximately seven miles north of the Prudhoe Bay field and extends into the Beaufort Sea.

Greater Kuparuk Area

We operate the Greater Kuparuk Area, which is comprised of the Kuparuk field and four satellite fields: Tarn, Tabasco, Meltwater, and West Sak. 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.

Our net crude oil production from the Kuparuk field averaged 54,100 barrels per day in 2007, compared with 59,900 barrels per day in 2006. The Kuparuk field is located about 40 miles west of Prudhoe Bay, and our ownership interest in the field is 55.3 percent.

Other fields within the Greater Kuparuk Area produced 11,500 net barrels per day of crude oil in 2007, compared with 13,400 net barrels per day in 2006, primarily from the Tarn, Tabasco, and Meltwater satellites. We have a 55.4 percent interest in Tarn and Tabasco and a 55.5 percent interest in Meltwater. The Greater Kuparuk Area also includes the West Sak heavy-oil field. Our net crude oil production from

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West Sak averaged 8,000 barrels per day in 2007, compared with 8,400 barrels per day in 2006. We have a 52.2 percent interest in this field.

Western North Slope

The Alpine field, located west of the Kuparuk field, produced at a net rate of 59,200 barrels of oil per day in 2007, compared with 74,100 barrels per day in 2006. We are the operator and hold a 78 percent interest in Alpine and two satellite fields.

The Alpine satellite fields, Nanuq and Fiord, began production in 2006. The fields produced at a net rate of 20,900 barrels of oil per day in 2007, compared with 4,300 barrels of oil per day in 2006. Peak production is expected in 2008. The oil is processed through the existing Alpine facilities.

We and our co-venturer are pursuing state, local and federal permits for additional Alpine satellite developments in the National Petroleum Reserve Alaska (NPR-A), including the Qannik satellite field discovery announced in 2006. Plans include developing the field from an existing Alpine drill site. Production from Qannik is expected to commence by late 2008.

Cook Inlet Area

Our assets in Alaska also include the North Cook Inlet field, the Beluga River field, and the Kenai liquefied natural gas (LNG) facility, all of which we operate.

We have a 100 percent interest in the North Cook Inlet field. Net production in 2007 averaged 66 million cubic feet per day of natural gas, compared with 88 million cubic feet per day in 2006. Production from the North Cook Inlet field is used to supply our share of gas to the Kenai LNG plant (discussed below).

Our interest in the Beluga River field is 33 percent. Net production averaged 35 million cubic feet per day of natural gas in 2007, compared with 49 million cubic feet per day in 2006. Gas from the Beluga River field is sold to local utilities and industrial consumers, and is used as back-up 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, utilizing two LNG tankers for transport. We sold 31.2 net billion cubic feet in 2007, compared with 41.3 net billion cubic feet in 2006. In January 2007, we and our co-venturer filed for a two-year extension of the Kenai LNG plant s export license with the U.S. Department of Energy, which would extend the export license through March 31, 2011. In January 2008, the state of Alaska announced its unconditional support for the requested license extension as the result of an agreement between the state, us and our co-venturer. The agreement addresses future drilling in the Cook Inlet, sale of seismic and well data to third parties, terms of access to the LNG plant and a framework to negotiate state support of potential future export license extensions.

Exploration

In 2007, we drilled six exploration wells. Two wells were classified as dry holes and four wells encountered commercial quantities of oil. One of the successful wells is located in the West Sak field, and three are in the Tarn field. We also acquired more than 2,360 square kilometers of 3D seismic and were the successful bidder in two lease sales, acquiring two lease blocks covering 8,253 acres.

Transportation

We transport the petroleum liquids produced on the North Slope to market through the Trans-Alaska Pipeline System (TAPS). TAPS is comprised of an 800-mile pipeline, marine terminal, spill response and escort vessel system that ties the North Slope of Alaska to the port of Valdez in south-central Alaska.

A project to upgrade TAPS pump stations began in 2004. The phased project startup that began in the first quarter of 2007 is progressing, and two of the four pump stations ultimately targeted for upgrade are

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currently online. We have a 28.3 percent ownership interest in TAPS. 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 Alaska North Slope production. Polar Tankers operates five ships in the Alaskan crude trade, chartering additional third-party-operated vessels as necessary. Beginning with the *Polar Endeavour* in 2001, Polar Tankers has brought into service five double-hulled tankers. The fifth and final tanker, the *Polar Enterprise,* began Alaska North Slope service in February 2007.

In late 2007, we submitted a proposal to the governor of Alaska to advance the development of the Alaska Natural Gas Pipeline Project. The proposed pipeline would transport approximately 4 billion cubic feet per day of natural gas from the Alaska North Slope to markets in Canada and the United States. We have a 36.1 percent non-operator interest in the Greater Prudhoe Area fields that are expected to be a primary source of natural gas to be shipped in the proposed pipeline. Our proposal was submitted as an alternative to the process the Alaska Legislature established in its Alaska Gasline Inducement Act (AGIA). In our proposal, we stated our willingness to make significant investments, without state matching funds, to advance this project. In January 2008, we received a letter from the governor of Alaska stating our alternative does not give the state a reason to deviate from the AGIA process. We formally responded to the governor s letter on January 24, 2008. As a result of the lack of engagement by the state of Alaska on our proposal, we are reassessing how best to advance the Alaska natural gas pipeline project. During this reassessment, as an initial step we will continue planning and contracting efforts in preparation for route reconnaissance and environmental studies starting in June 2008. We expect to continue to testify before the Alaska Legislature and engage the Alaska public with our view of the best path forward to advance the gas pipeline project.

Lower 48 States

Gulf of Mexico

At year-end 2007, our portfolio of producing properties in the Gulf of Mexico included one operated field and five fields operated by our co-venturers.

We operate and hold a 75 percent interest in the Magnolia field in Garden Banks Blocks 783 and 784. Magnolia utilizes a tension-leg platform in 4,700 feet of water. Net production from Magnolia averaged 7,300 barrels per day of liquids and 13 million cubic feet per day of natural gas in 2007, compared with 17,800 barrels per day of liquids and 44 million cubic feet per day of natural gas in 2006.

We hold a 16 percent interest in the unitized Ursa field located in the Mississippi Canyon area. Ursa utilizes a tension-leg platform in approximately 3,900 feet of water. We also own a 16 percent interest in the Princess field, a northern, subsalt extension of the Ursa field. Our total net production from the unitized area in 2007 averaged 13,400 barrels per day of liquids and 16 million cubic feet per day of natural gas, compared with 14,400 barrels per day of liquids and 18 million cubic feet per day of natural gas in 2006.

The unitized K2 field is comprised of seven blocks in the Green Canyon area. In December 2006, the unit was expanded from two to seven blocks, and our working interest was reduced from 16.8 to 12.4 percent. Net production from K2 averaged 3,500 barrels per day of liquids and 2 million cubic feet per day of natural gas in 2007, compared with 2,150 barrels per day of liquids and 1 million cubic feet per day of natural gas in 2006.

Onshore

Our 2007 onshore production primarily consisted of natural gas, with the majority of production located in the San Juan Basin, the Permian Basin, the Lobo Trend, the Bossier Trend, and the Panhandles of Texas and Oklahoma. We also have operations in the Wind River, Anadarko, and Fort Worth Basins, as well as east Texas and north and south Louisiana. We have other onshore properties in the Williston Basin, the Piceance Basin, and the Cedar Creek Anticline.

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The San Juan Basin, located in northwest New Mexico and southwest Colorado, includes the majority of our coalbed methane (CBM) production. In addition, we continue to pursue development opportunities in three conventional formations in the San Juan Basin. Net production from the San Juan Basin averaged 49,800 barrels per day of liquids and 971 million cubic feet per day of natural gas in 2007, compared with 41,900 barrels per day of liquids and 851 million cubic feet per day of natural gas in 2006.

In addition to our CBM production from the San Juan Basin, we also hold CBM acreage positions in the Uinta Basin in Utah, the Black Warrior Basin in Alabama, and the Piceance Basin in Colorado.

Activities in 2007 primarily were centered on continued optimization and development of these assets. Combined production from all Lower 48 onshore fields in 2007 averaged a net 2,100 million cubic feet per day of natural gas and 157,000 barrels per day of liquids, compared with 1,900 million cubic feet per day of natural gas and 128,000 barrels per day of liquids in 2006.

Transportation

In June 2006, we acquired a 24 percent interest in West2East Pipeline LLC, a company holding a 100 percent interest in Rockies Express Pipeline LLC (Rockies Express). Rockies Express plans to construct a 1,679-mile natural gas pipeline from Colorado to Ohio. The pipeline is expected to be completed in 2009.

Exploration

In the Lower 48 states, we own undeveloped mineral interests in 7.6 million net acres and hold leases on 2.2 million undeveloped net acres. In 2007, we successfully completed 81 gross exploration wells. Areas of focus in 2007 included the east Texas Bossier Trend, deepwater Gulf of Mexico, Bakken play in the Williston Basin, and the Barnett Trend in the Fort Worth Basin. Other areas with active exploration drilling programs included the Anadarko and Piceance Basins, and south Texas.

E&P EUROPE

In 2007, E&P operations in Europe contributed 22 percent of E&P s worldwide liquids production, compared with 23 percent in 2006. Europe operations contributed 19 percent of natural gas production in 2007, compared with 21 percent in 2006. Our European assets are principally located in the Norwegian and U.K. sectors of the North Sea. We also have operations in the East Irish Sea and the Netherlands.

Norway

The Greater Ekofisk Area, located approximately 200 miles offshore Norway in the center of the North Sea, is composed of four producing fields: Ekofisk, Eldfisk, Embla, and Tor. The Ekofisk complex serves as a hub for petroleum operations in the area, with surrounding developments utilizing the Ekofisk infrastructure. Net production in 2007 from the Greater Ekofisk Area was 102,700 barrels of liquids per day and 103 million cubic feet of natural gas per day, compared with 121,700 barrels of liquids per day and 123 million cubic feet of natural gas per day in 2006. We are the operator and hold a 35.1 percent interest in Ekofisk.

During 2007, we continued to evaluate the optimal approach to redevelop the Eldfisk facilities. Our objective is to maintain and upgrade the facilities in order to continue production until the end of the license period in 2028.

We also have ownership interests in other producing fields in the Norwegian sector of the North Sea and Norwegian Sea, including a 24.3 percent interest in the Heidrun field, a 10.3 percent interest in the Statfjord field, a 23.3 percent interest in the Huldra field, a 1.6 percent interest in the Troll field, a 9.1 percent interest in the Visund field, a 6.4 percent interest in the Grane field, and a 2.4 percent interest in the Oseberg area. Our net production from these and other fields in the Norwegian sector of the North

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Sea and the Norwegian Sea averaged 67,300 barrels of liquids per day and 133 million cubic feet of natural gas per day in 2007, compared with 75,800 barrels of liquids per day and 147 million cubic feet of natural gas per day in 2006.

We and our co-venturers received approval from Norwegian authorities in 2004 for the Alvheim North Sea development. The development plans include a floating production storage and offloading (FPSO) vessel and subsea installations. Production from the field is targeted to commence in mid-2008. We have a 20 percent interest in the project.

In 2005, Norwegian and U.K. authorities approved the Statfjord Late-Life Project, a Statfjord-area gas recovery project which began production in October of 2007. We have a combined Norway/U.K. 15.2 percent interest in this project.

Transportation

We have interests in the transportation and processing infrastructure in the Norwegian North Sea, including a 35.1 percent interest in the Norpipe Oil Pipeline System and a 2.2 percent interest in Gassled, which owns most of the Norwegian gas transportation system.

Exploration

In 2007, we participated in one appraisal well and four exploration wells within the Oseberg licenses of the northern North Sea, license PL018 of the Greater Ekofisk Area, and PL281 in the Moere Basin of the Norwegian Sea. Drilling operations extended into 2008 on two of these wells, one of which concluded operations and was expensed as a dry hole in the first quarter of 2008. Drilling operations continue on the other well. Hydrocarbons were encountered in all three wells whose drilling operations were completed by the end of the year. One of these wells was successful and the remaining two wells are being evaluated.

In 2007, we were awarded three new North Sea exploration licenses in Norway PL404, PL399 and PL424.

United Kingdom

We have a 58.7 percent interest in the Britannia natural gas and condensate field, and own 50 percent of Britannia Operator Limited, the operator of the field. Our net production from Britannia averaged 252 million cubic feet of natural gas per day and 10,300 barrels of liquids per day in 2007, compared with 246 million cubic feet of natural gas per day and 10,100 barrels of liquids per day in 2006.

We have a 75 percent interest in the Brodgar field and an 83.5 percent interest in the Callanish field. First production from these two Britannia satellite fields is targeted for mid-2008.

We operate and hold a 36.5 percent interest in the Judy/Joanne fields, which together comprise J-Block. Additionally, the Jade field produces from a wellhead platform and pipeline tied to the J-Block facilities. We operate and hold a 32.5 percent interest in Jade. Together, these fields produced a net 14,300 barrels of liquids per day and 94 million cubic feet of natural gas per day in 2007, compared with 15,900 barrels of liquids per day and 133 million cubic feet of natural gas per day in 2006.

We have various ownership interests in 18 producing gas fields in the Rotliegendes and Carboniferous areas of the southern North Sea. Net production in 2007 averaged 276 million cubic feet per day of natural gas and 1,200 barrels of liquids per day, compared with 309 million cubic feet per day of natural gas and 1,200 barrels per day of liquids in 2006.

In 2006, the U.K. government approved a plan for the development of two new Saturn satellite fields in the Rotliegendes area of the southern North Sea Tethys and Mimas. We have a 25 percent interest in the Tethys field, and first production began in February 2007. We have a 35 percent interest in the Mimas field, and first production began in June 2007. These fields were producing a combined net 12 million cubic feet of natural gas per day at year-end 2007.

In 2007, the U.K. government approved a plan for the development of the Kelvin field in the Carboniferous area of the southern North Sea, in which we have a 50 percent operator interest. First production began in November 2007, and the field was producing at a net rate of approximately 54 million cubic feet of natural gas per day at year-end 2007.

We also have ownership interests in several other producing fields in the U.K. North Sea, including a 23.4 percent interest in the Alba field, a 40 percent interest in the MacCulloch field, and a 4.84 percent interest in the Statfjord field. Production from these and the other remaining fields in the U.K. sector of the North Sea averaged a net 20,500 barrels of liquids per day and 15 million cubic feet of natural gas per day in 2007, compared with 26,700 barrels of liquids per day and 34 million cubic feet of natural gas per day in 2006. We sold our interests in the Everest and Armada fields during the first quarter of 2007.

We have a 24 percent interest in the Clair field development in the Atlantic Margin. First production from Clair began in early 2005 from a conventional platform, with peak production expected in 2008. Net production in 2007 averaged 7,000 barrels of liquids per day and 1 million cubic feet of natural gas per day, compared with 6,000 barrels of liquids per day and 1 million cubic feet of natural gas per day in 2006.

We have a 100 percent ownership interest in the Millom, Dalton and Calder fields in the East Irish Sea, which are operated on our behalf by a third party. The natural gas produced from these fields is transported onshore, processed and sold into the U.K. spot market. Net production in 2007 averaged 36 million cubic feet of natural gas per day, compared with 38 million cubic feet of natural gas per day in 2006.

Transportation

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

We operate two terminals in the United Kingdom: the Teesside oil terminal, in which we have a 29.3 percent interest, and the Theddlethorpe gas terminal, in which we have a 50 percent interest. We also have a 100 percent ownership interest in the Rivers Gas Terminal in the United Kingdom.

Exploration

In 2007, we participated in five appraisal wells and four exploration wells and were awarded an interest in one North Sea exploration license in the North Sea P1423.

In the Atlantic Margin West of Shetland region, and adjacent to the Clair field, operations concluded on two appraisal wells, both of which encountered hydrocarbons. The appraisal program confirmed the viability of the Clair Ridge discovery, and development planning is under way.

In the southern North Sea, one appraisal well and two exploration wells were drilled. The appraisal well was successfully completed and began first production in 2007. Operations concluded on the two exploration wells, both of which encountered hydrocarbons. One of these exploration wells was successfully tested.

In the central North Sea, we concluded operations on one exploration well and one appraisal well. The exploration well was unsuccessful and expensed as a dry hole. The appraisal well encountered hydrocarbons. Operations continue on another exploration well, located adjacent to and east of the 2006

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Jasmine gas and condensate discovery. Operations also continue on an appraisal well, which is located to the north of the 2006 Jackdaw discovery.

Denmark

We sold our ownership interests in the Danish sector of the North Sea in 2007.

Netherlands

We have varying non-operated production interests in the Dutch sector of the North Sea, as well as interests in offshore pipelines and an onshore gas plant and terminal at Den Helder. Net production in 2007 averaged 52 million cubic feet of natural gas per day, compared with 34 million cubic feet of natural gas per day in 2006.

Exploration

In 2007, we participated in one exploration well and one appraisal well in the southern North Sea, both of which encountered hydrocarbons. The exploration well, located within the JDA K15 license, was successfully completed and began production in 2007. The appraisal well, located within the E18a license, appraised additional potential to a 2006 discovery. The well was successful and a field development plan is being progressed.

E&P CANADA

In 2007, E&P operations in Canada contributed 7 percent of E&P s worldwide liquids production (excluding Syncrude production), compared with 5 percent in 2006. Canadian operations contributed 22 percent of E&P s worldwide natural gas production in 2007, compared with 20 percent in 2006.

Oil and Gas Operations

Western Canada

Operations in western Canada encompass properties in Alberta, northeastern British Columbia and southern Saskatchewan. The properties in northern Alberta and northeastern British Columbia contain a mix of oil and natural gas, and are primarily accessible only in the winter. The properties in the central and foothills areas of Alberta mainly produce natural gas. The properties in southern Alberta and southern Saskatchewan produce natural gas and medium-to-heavy oil. Net production from these oil and gas operations in western Canada averaged 46,000 barrels per day of liquids and 1,106 million cubic feet per day of natural gas in 2007, compared with 50,000 barrels per day of liquids and 983 million cubic feet per day of natural gas in 2006.

In January 2007, we completed the sale of oil and natural gas producing properties and undeveloped acreage in western Canada, including oil properties in northern, central and southern Alberta and natural gas properties in southwestern Alberta and southeastern Saskatchewan. Combined, net production from these properties contributed approximately 18,000 BOE per day to our 2006 average production.

Surmont

We have a 50 percent operating interest in the Surmont lease, located approximately 35 miles south of Fort McMurray, Alberta. The Surmont project uses an enhanced thermal oil recovery method called steam-assisted gravity drainage (SAGD). Steam injection began in the second quarter of 2007, and first production was achieved in the fourth quarter of 2007. Peak production is expected in 2014. We anticipate processing our share of the heavy oil produced as a feedstock in our owned and affiliated U.S. refineries.

EnCana Joint Venture

In October 2006, we announced a business venture with EnCana Corporation (EnCana), to create an integrated North American heavy-oil business. The transaction closed on January 3, 2007. The venture consists of two 50/50 business ventures, a Canadian upstream general partnership, FCCL Oil Sands Partnership (FCCL), and a U.S. downstream limited liability company, WRB Refining LLC. We use the equity method of accounting for our investments in both entities.

FCCL s operating assets consist of the Foster Creek and Christina Lake SAGD bitumen projects, both located in the eastern flank of the Athabasca oil sands in northeast Alberta. EnCana is the operator and managing partner of FCCL. Our share of production was 26,800 barrels per day in 2007.

See the Refining and Marketing (R&M) section for information on WRB Refining LLC.

Consistent with our practice and in accordance with U.S. Securities and Exchange Commission guidelines, we use year-end prices for hydrocarbon reserve estimation for both our Surmont and FCCL properties. Bitumen prices can be seasonal, often reaching low levels at year end. Conversely, natural gas prices, a significant cost component of the development, can be seasonally high at year end. As a result, the ability to reflect proved reserves for SAGD bitumen projects can fluctuate because of the economics associated with this seasonality. For example, at year-end 2005, we could not reflect any proved reserves for Surmont. At year-end 2007, we were able to reflect proved reserves for Surmont and FCCL. However, it is reasonably possible that future year-end bitumen and natural gas price levels may result in the de-booking of some or all of our Surmont and FCCL proved reserves.

Parsons Lake/Mackenzie Gas Project

We are working with three other energy companies, as members of the Mackenzie Delta Producers Group, on the development of the Mackenzie Valley pipeline and gathering system, which is proposed to transport onshore gas production from the Mackenzie Delta in northern Canada to established markets in North America. We have a 75 percent interest in the Parsons Lake gas field, one of the primary fields in the Mackenzie Delta that would anchor the pipeline development. This pipeline project faces significant regulatory and construction cost issues; therefore, no definitive startup date can be estimated at this time.

Exploration

We hold exploration acreage in four areas of Canada: the Western Canada Sedimentary Basin, offshore eastern Canada, the Mackenzie Delta/Beaufort Sea, and the Arctic Islands. Within the Western Canada Sedimentary Basin, we hold exploration acreage throughout the basin, including the foothills of western Alberta and eastern British Columbia. In the foothills, we drilled three exploratory wells in 2007 two will be completed as producing wells and one will be tested and evaluated. During 2007, we also drilled three exploratory wells on acreage in the central Alberta Nisku project that resulted in one producer, while the remaining wells were expensed as dry holes. One successful exploration well was drilled in late 2007 on a recently defined Montney gas prospect in northeast British Columbia. Throughout the rest of western Canada, we participated in drilling approximately 48 lower risk exploratory wells near our producing assets. In the Mackenzie Delta, we were successful in acquiring additional offshore acreage following the 2004 Umiak discovery.

Other Canadian Operations

Syncrude Canada Ltd.

We own a 9 percent interest in the Syncrude Canada Ltd. (SCL) joint venture, created for the purpose of mining shallow deposits of oil sands, extracting the bitumen, and upgrading it into a light sweet crude oil called Syncrude. The primary plant and facilities are located at Mildred Lake, about 25 miles north of Fort McMurray, Alberta, with an auxiliary mining and extraction facility approximately 20 miles from the Mildred Lake plant. SCL, as operator of the joint venture, holds eight oil sands leases and the associated surface rights, of which our share is approximately 22,400 net acres. Our net share of production averaged 23,400 barrels per day in 2007, compared with 21,100 barrels per day in 2006.

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The U.S. Securities and Exchange Commission s regulations define this project as mining-related and not part of conventional oil and gas operations. As such, Syncrude operations are not included in our proved oil and gas reserves or production as reported in our supplemental oil and gas information.

E&P SOUTH AMERICA

In 2007, E&P operations in South America contributed 5 percent of E&P s worldwide liquids production, compared with 10 percent in 2006. This decrease primarily relates to the expropriation of our oil interests in Venezuela in the second quarter of 2007, as noted below. We also have interests in Ecuador, Argentina and Peru.

Venezuela

Petrozuata, Hamaca and Corocoro

On June 26, 2007, we announced we had been unable to reach agreement with respect to our migration to an *empresa mixta* structure mandated by the Nationalization Decree. In response, Petróleos de Venezuela S.A. (PDVSA) or its affiliates directly assumed the activities associated with and control over ConocoPhillips interests in the Petrozuata and Hamaca heavy-oil ventures and the offshore Corocoro development project.

In the second quarter of 2007, we recorded a $4,512 million (after-tax) non-cash impairment related to the expropriation of our oil interests in Venezuela. For additional information, see the Expropriated Assets section of Note 13 Impairments, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Plataforma Deltana Block 2

We have a 40 percent interest in Plataforma Deltana Block 2. The block is operated by our co-venturer and holds a gas discovery made by PDVSA in 1983. PDVSA has the option to enter the project with a 35 percent interest, which would proportionately reduce our interest in the project to 26 percent. In December 2007, the co-venturers presented the notification of commerciality and submitted a conditional development plan for governmental approval in compliance with license requirements. Several critical components required to progress an investment decision have not yet been defined by the government. Assuming timely resolution of these components, we expect a preliminary engineering study could be completed by late 2008, and a more significant developmental engineering study could be completed by late 2009.

Ecuador

In Ecuador, we hold a 42.5 percent interest in Block 7 and a 46.25 percent interest in Block 21. Net production in 2007 averaged 10,300 barrels of crude oil per day, compared with 6,800 barrels per day in 2006.

Argentina

We have a 25.7 percent interest in the producing Sierra Chata concession in Argentina. Net production in 2007 averaged 19 million cubic feet of natural gas per day, compared with 17 million cubic feet per day in 2006.

Peru

We have varying ownership interests in six exploration blocks in Peru. In the first quarter of 2007, we acquired a 100 percent interest in Block 129. In Block 57, we drilled one exploration well that encountered hydrocarbons.

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E&P ASIA PACIFIC

In 2007, E&P operations in the Asia Pacific area contributed 10 percent of E&P s worldwide liquids production and 11 percent of natural gas production, compared with 11 percent and 12 percent in 2006, respectively.

Indonesia

We operate seven production sharing contracts (PSCs) in Indonesia. Production from Indonesia in 2007 averaged a net 330 million cubic feet per day of natural gas and 11,800 barrels per day of oil, compared with 319 million cubic feet per day of natural gas and 12,400 barrels per day of oil in 2006. Natural gas is sold under long-term contracts benchmarked to crude oil prices to markets in Indonesia and Singapore. Natural gas is also sold to the Indonesian domestic markets under U.S.-dollar-denominated, fixed-price contracts. Our assets are concentrated in two core areas: the West Natuna Sea and onshore South Sumatra.

Offshore

We operate four offshore PSCs: South Natuna Sea Block B, Ketapang, Amborip VI, and Kuma. We sold our 25 percent non-operator interest in the Pangkah PSC, offshore East Java, in the third quarter of 2007.

The South Natuna Sea Block B PSC, in which we have a 40 percent interest, has two producing oil fields and 16 gas fields in various stages of development. In late 2006, gas production began from the Hiu gas field. In December 2007, crude oil and natural gas production began from the Kerisi field and development continued on the North Belut field.

Onshore

We operate three onshore PSCs. Two are in South Sumatra: Corridor PSC and South Jambi B. We also operate Warim in Papua. In January 2007, we sold our 50 percent working interest in the Block A PSC in North Sumatra, and we sold our 60 percent interest in Corridor TAC in September 2007. In November 2007, the Sakakemang Joint Operating Body expired. We also transferred our non-operator interest in the Banyumas PSC in Java to our partners effective January 2008.

The Corridor PSC is located onshore South Sumatra and we have a 54 percent interest. We operate six oil fields and six natural gas fields, and supply natural gas from the Grissik and Suban gas processing plants to the Duri steamflood in central Sumatra and to markets in Singapore and Batam. The Suban Phase II project, an expansion of the existing Suban gas plant in the Corridor PSC, began producing in October 2007.

We have a 45 percent interest in the South Jambi B PSC, which is also located in South Sumatra. This shallow gas project supplies natural gas to Singapore.

Transportation

We are a 35 percent owner of TransAsia Pipeline Company Pvt. Ltd., a consortium company, which has a 40 percent ownership in PT Transportasi Gas Indonesia, an Indonesian limited liability company, which owns and operates the Grissik to Duri, and Grissik to Singapore, natural gas pipelines.

Exploration

In January 2007, we signed a new PSC agreement for a 60 percent interest in the Kuma block, which is located in Makassar Straits, between the islands of Kalimantan and Sulawesi. The acreage contains multiple exploration targets. A 3D survey will commence on the Kuma PSC in 2008. In addition, exploration work will continue on the Amborip VI PSC. Exploration wells are being planned for drilling in 2009 on both of these PSCs.

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China

The Xijiang development consists of two fields located approximately 80 miles south of Hong Kong in the South China Sea. The facilities include two manned platforms and an FPSO vessel. Our combined net production of crude oil from the Xijiang fields averaged 7,900 barrels per day in 2007, compared with 10,100 barrels per day in 2006.

Production from the Peng Lai 19-3 field in Bohai Bay Block 11-05 averaged 10,500 net barrels of oil per day in 2007, compared with 13,800 net barrels per day in 2006. We have a 49 percent interest, with the remainder held by the China National Offshore Oil Corporation.

In 2005, we received government approval to develop Phase II of the Peng Lai 19-3 field, as well as concurrent development through the same facilities of the nearby Peng Lai 25-6 field. The first wellhead platform of Phase II was placed into operation in 2007. The FPSO vessel is scheduled to be installed in late 2008 with production beginning in early 2009.

We have a 24.5 percent interest in the Panyu field and a 100 percent interest in the Ba Jiao Chang (BJC) field. The Panyu development is an offshore project located approximately 36 miles southwest of the Xijiang development. The field produced 12,700 net barrels of oil per day in 2007, and 9,100 net barrels of oil per day in 2006. The BJC gas field is located onshore in Sichuan province. In 2007, net gas production averaged 11 million cubic feet per day, compared with 7 million cubic feet per day in 2006.

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, four exploration blocks, and one gas pipeline transportation system.

We have a 23.3 percent interest in Block 15-1 in the Cuu Long Basin. Net production in 2007 was 13,700 barrels of oil per day, compared with 11,800 barrels per day in 2006. The oil is being processed through a one-million-barrel FPSO vessel. Development of the Su Tu Vang field continued in 2007. First oil production is targeted for late 2008. During 2007, preliminary engineering was completed on the Su Tu Den Northeast development. Appraisal of the Su Tu Trang and Su Tu Nau discoveries continued in 2007.

We have a 36 percent interest in the Rang Dong field in Block 15-2 in the Cuu Long Basin. All wellhead platforms produce into an FPSO vessel. Net production in 2007 was 8,500 barrels of liquids per day and 15 million cubic feet per day of natural gas, compared with 13,000 barrels per day and 21 million cubic feet per day in 2006.

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.

Exploration

A successful appraisal well was drilled during 2007 in the Su Tu Nau field in the northeast area of Block 15-1. Further appraisal plans and potential development options for this field are currently being evaluated.

In 2007, we executed an agreement with a co-venturer to partially exchange interests in offshore Blocks 5-2 and 5-3. Within these two blocks, joint appraisal and development plans are currently under way for the Moc Tinh and Hai Thach discoveries.

We also continued to evaluate the potential of our interests in deepwater Blocks 133 and 134 in the Nam Con Son Basin.

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Timor Sea and Australia

Bayu-Undan

We operate and hold an ownership interest in the Bayu-Undan field located in the Timor Sea. In accordance with various governance agreements, a redetermination of the ownership interest in the Bayu-Undan Joint Venture, Darwin LNG Pty Ltd and the Bayu-Undan Pipeline Joint Venture was completed in 2007. The redetermination increased our controlling interest from 56.7 percent to 57.15 percent. The Bayu-Undan field was developed in two phases. Phase I was a gas-recycle project, where condensate and natural gas liquids were separated and removed and the dry gas was re-injected into the reservoir. This phase began production in February 2004, and averaged a net rate of 34,100 barrels of liquids per day in 2007, compared with 53,400 barrels per day in 2006.

Phase II involved the installation of a natural gas pipeline from the field to Darwin, Australia, and construction of an LNG facility located at Wickham Point, Darwin, to meet gross contracted sales of up to 3 million tons of LNG per year for a period of 17 years to customers in Japan. The LNG facility was completed and began full operation in 2006, with the first LNG cargo loaded in February 2006. Our net share of natural gas production from the Bayu-Undan field was 189 million cubic feet per day in 2007, compared with 200 million cubic feet per day in 2006. The natural gas production from the Bayu-Undan field is used by the Darwin LNG plant.

In 2007, Bayu-Undan and the Darwin LNG facility were shutdown for a 35-day period due to planned maintenance and facility improvements.

Greater Sunrise

We have a 30 percent interest in the Greater Sunrise gas and condensate field located in the Timor Sea. In January 2006, agreement was reached between the governments of Australia and Timor-Leste concerning sharing of revenues from the anticipated development of the Greater Sunrise field. In February 2007, the government of Timor-Leste ratified the International Unitisation Agreement (IUA) and the governments of Timor-Leste and Australia both ratified the treaty on Certain Maritime Arrangements in the Timor Sea. The Australian government ratified the IUA in 2004.

Ratification of these two treaties created the legal and regulatory framework required by us and our co-venturers to reconsider development options for the Greater Sunrise fields. Key challenges to be resolved before significant funding commitments can be made include: ensuring the reservoir is adequately appraised, partner and government alignment on the development concept, and establishing fiscal stability arrangements. Immediate activity is focused on reprocessing seismic data to define the remaining appraisal program and commencing the development concept screening phase.

Other

A cooperative field development agreement for the Athena/Perseus (WA-17-L) gas field, located offshore Western Australia, was executed in 2001. In 2007, our net share of production was 34 million cubic feet of natural gas per day, compared with 35 million cubic feet of natural gas per day in 2006. Early in the third quarter of 2007, abandonment of the Elang/Kakatua/Kakatua North fields commenced and production ceased.

Exploration

We are the operator of the NT/P 69 and the NT/P 61 licenses, located offshore Northern Territory, Australia, which include the Caldita and Barossa discoveries. A Caldita appraisal well drilled in early 2007 encountered hydrocarbons, but it was expensed as a dry hole. Acquisition of seismic data concluded in 2007, and interpretation of this data will begin in 2008 to further evaluate these discoveries.

In 2007, we were awarded operatorship and a 60 percent interest in the Western Australia offshore exploration license WA-398-P, which is adjacent to existing ConocoPhillips acreage. The work program obligation includes 3D seismic and four exploration wells.

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In the fourth quarter of 2007, we sold our interests in Western Australia offshore blocks WA-341-P, WA-343-P and WA-344-P.

Malaysia

Exploration

We have interests in deepwater Blocks G and J, located off the east Malaysian state of Sabah. In late 2007, we and our co-venturers sanctioned the Gumusut-Kakap field development that incorporates the 2003 Gumusut discovery in Block J. Also in 2007, we participated in two exploration wells. We had a discovery in the Petai field in Block G. Petai and previous Block G discoveries are being evaluated as part of a broader area development plan. One Block J well was expensed as a dry hole.

In 2007, we signed a new PSC that includes both oil and gas rights for the Kebabangan field and three additional discoveries. Kebabangan is moving toward field development. The remaining discoveries are awaiting appraisal.

E&P MIDDLE EAST AND AFRICA

In 2007, E&P operations in the Middle East and Africa contributed 8 percent of E&P s worldwide liquids production and 2 percent of natural gas production, compared with 10 percent and 3 percent in 2006, respectively.

Qatar

Qatargas 3 is an integrated project, jointly owned by Qatar Petroleum (68.5 percent), ConocoPhillips (30 percent) and Mitsui & Co., Ltd. (1.5 percent). The project comprises upstream natural gas production facilities to produce approximately 1.4 billion gross cubic feet per day of natural gas from Qatar s North field over the 25-year life of the project. The project also includes a 7.8-million-gross-ton-per-year LNG facility. The LNG will be shipped from Qatar in a fleet of LNG vessels, and is destined for sale primarily in the United States. The first LNG cargos are expected to be loaded from Qatargas 3 in 2009.

In the fourth quarter of 2007, we signed agreements with affiliates of ExxonMobil and Qatar Petroleum that provide for a 12.4 percent ownership interest in the Golden Pass LNG regasification facility and associated pipeline (Golden Pass). The facilities are currently being constructed on the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. Subject to the negotiation of definitive agreements, ConocoPhillips will also secure capacity rights in the Golden Pass LNG terminal and pipeline to manage a substantial portion of the LNG we will purchase from Qatargas 3. In addition to the United States, other market alternatives for Qatargas 3 LNG production are being evaluated.

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

In July 2007, we committed to sponsor a water sustainability center in the Qatar Science & Technology Park. The center will conduct applied research and testing in the industrial, municipal, and agricultural water sectors. The primary focus will be on removing contaminants from petroleum industry water.

In December 2007, ConocoPhillips and Qatar Petroleum International, a wholly owned subsidiary of Qatar Petroleum, announced the two companies signed a Memorandum of Understanding to pursue and develop international energy projects outside of Qatar.

Dubai

Our oil concession offshore Dubai ended effective April 2007.

Algeria

We have interests in three fields in Block 405a: a 65 percent operating interest in the Menzel Lejmat North (MLN) field; a 3.73 percent interest in the Ourhoud field; and a 16.9 percent interest in the EMK (El Merk) oil field unit. Net production from these fields averaged 10,800 barrels of crude oil per day in 2007, compared with 9,800 barrels per day in 2006.

Libya

ConocoPhillips holds a 16.33 percent interest in the Waha concessions in Libya. The concessions encompass nearly 13 million acres located in the Sirte Basin. Net crude oil production averaged 46,900 barrels per day in 2007, compared with 50,400 barrels per day in 2006, including 3,800 barrels per day associated with the complete recovery of our 1986 underlift position.

Egypt

During the first quarter of 2007, we sold our 50 percent non-operated interest in a concession in Egypt that included the development of the Tao gas field and its associated facilities.

Nigeria

At year-end 2007, we were producing from four onshore Oil Mining Leases (OMLs), in which we have a 20 percent non-operator interest. Our net production from these leases was 19,300 barrels of liquids per day and 117 million cubic feet of natural gas per day in 2007, compared with 24,500 barrels per day and 138 million cubic feet per day in 2006. In 2007, we continued development of projects in the onshore OMLs to supply feedstock natural gas under a gas sales contract with Nigeria LNG Limited, which owns an LNG facility on Bonny Island.

We have a 20 percent interest in a 480-megawatt gas-fired power plant in Kwale, Nigeria. The plant came online in March 2005, and supplies electricity to Nigeria s national electricity supplier. The plant consumes 68 million gross cubic feet per day of natural gas, including that sourced from our proved natural gas reserves in the OMLs.

During 2007, Brass LNG Limited (Brass LNG) continued to progress activities for a planned LNG facility to be constructed in Nigeria s central Niger Delta. We have a 17 percent equity interest in Brass LNG.

Exploration

During 2007, we made an onshore exploration discovery in OML 61, and the well is now producing. During the fourth quarter of 2007, we initiated drilling of an appraisal well in deepwater Oil Prospecting License (OPL) 214. The well encountered hydrocarbons, and drilling operations concluded in the first quarter of 2008. In the first quarter of 2007, we recorded a leasehold impairment related to OPL 248. In the second quarter of 2007, we relinquished our interest in OPL 318.

E&P RUSSIA AND CASPIAN

Russia

Polar Lights

We have a 50 percent equity ownership interest in Polar Lights Company, a Russian limited liability company established in January 1992 to develop fields in the Timan-Pechora Basin in northern Russia.

Our net production from Polar Lights averaged 11,800 barrels of oil per day in 2007, compared with 12,100 barrels per day in 2006, and is included in equity affiliate production.

NMNG

In June 2005, ConocoPhillips and LUKOIL created the OOO Naryanmarneftegaz (NMNG) joint venture to develop resources in the northern part of Russia s Timan-Pechora province. We have a 30 percent ownership interest with a 50 percent governance interest in NMNG. We use the equity method of accounting for this joint venture. NMNG is working to develop the Yuzhno Khylchuyu (YK) field.

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. LUKOIL intends to complete an expansion of the terminal s oil-throughput capacity from 30,000 barrels per day to 240,000 barrels per day to accommodate production from the YK field.

Caspian

In the Caspian Sea, we have a 9.26 percent interest in the Republic of Kazakhstan s North Caspian Sea Production Sharing Agreement (NCSPSA), which includes the Kashagan field. Detailed design, procurement and construction activities continued on the Kashagan oil field development following approval by the Republic of Kazakhstan for the development plan and budget in 2004. The first phase of field development currently being executed includes the construction of artificial drilling islands with processing facilities and living quarters, and pipelines to carry production onshore. The initial production phase of the contract is for 20 years, with options to extend the agreement an additional 20 years. During 2007, the Republic of Kazakhstan triggered dispute proceedings under the NCSPSA following submission of a revised development plan and budget reflecting Kashagan cost increases and schedule delays. The international co-venturers signed a Memorandum of Understanding in January 2008, agreeing to the proportional dilution of their equity interest to allow the state-owned energy company, JSC NC KazMunaiGaz, to increase its ownership interest from 8.33 percent to 16.81 percent, effective January 1, 2008, subject to the completion of definitive agreements on dilution and other matters. As a result, our interest in the NCSPSA would be reduced from 9.26 percent to 8.40 percent, effective January 2008. In addition, a joint operating company, with significant involvement from the larger owners, will operate future phases of Kashagan. First production is expected at the end of 2011.

Transportation

We have a 2.5 percent interest in the Baku-Tbilisi-Ceyhan (BTC) pipeline. This 1,760-kilometer pipeline transports crude oil from the Caspian region through Azerbaijan, Georgia and Turkey, for tanker loadings at the Mediterranean port of Ceyhan. The BTC pipeline became operational in mid-2006.

Exploration

In 2007, appraisal and development concept studies continued for Kalamkas More, Kairan and Aktote. Testing operations on a Kairan appraisal well drilled in 2006 were successfully completed. Concept studies for development are under way for all three fields.

E&P OTHER

LNG

In late 2003, we signed an agreement with Freeport LNG Development, L.P. (Freeport LNG) to participate in its proposed LNG receiving terminal in Quintana, Texas. This agreement gave us 1 billion cubic feet per day of regasification capacity in the terminal and a 50 percent interest in the general partnership managing the venture. The terminal is designed to have capacity of 1.5 billion cubic feet per day. Freeport LNG received final approval in 2005 from the Federal Energy Regulatory Commission (FERC) to construct and operate the facility. Construction began in 2005, and commercial startup is expected in

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2008. In 2005, we executed an option to secure 0.3 billion cubic feet per day of capacity in a subsequent expansion of the facility, which is subject to certain regulatory approvals and commercial decisions to proceed. In 2007, we released 0.1 billion cubic feet per day of our original 1 billion cubic feet per day regasification capacity to allow Freeport LNG more flexibility in marketing the remaining regasification capacity.

In order to deliver the natural gas from the Freeport terminal to market, we are constructing a 32-mile, 42-inch pipeline from the Freeport terminal to a point near Iowa Colony, Texas. Construction began in the first quarter of 2007 and is planned for completion in early 2008 to coincide with the Freeport terminal startup.

In 2007, we sold our 50 percent interest in Sound Energy Solutions, a company pursuing a proposed LNG regasification terminal in the Port of Long Beach, California. In the United Kingdom, we, along with the other Norsea Pipeline Limited shareholders, submitted applications in 2007 to obtain planning permission for an LNG regasification facility and combined heat and power plant at the existing Norsea Pipeline Limited oil terminal site at Teesside, United Kingdom. A decision on the applications is expected in 2008. We withdrew from a project to develop an LNG regasification terminal at the Port of Eemshaven in the Netherlands.

Commercial

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

Natural Gas Pricing

Compared with the more global nature of crude oil commodity pricing, natural gas prices have historically varied more in different regions of the world. We produce natural gas from regions around the world that have significantly different supply, demand and regulatory circumstances, typically resulting in significantly lower average sales prices than in the Lower 48 region of the United States. Moreover, excess supply conditions that exist in certain parts of the world cannot easily serve to mitigate the relatively high-price conditions in the Lower 48 states and other markets because of a lack of infrastructure and because of the difficulties in transporting natural gas. We, along with other companies in the oil and gas industry, are planning long-term projects in regions of excess supply to install the infrastructure required to produce and liquefy natural gas for transportation by tanker and subsequent regasification in regions where market demand is strong, such as the Lower 48 states or certain parts of Asia, but where supplies are not as plentiful. Due to the significance of the overall investment in these long-term projects, the natural gas sales prices (to a third-party LNG facility) or transfer prices (to a company-owned LNG facility) in the areas of excess supply are expected to remain well below sales prices for natural gas that is produced closer to areas of high demand and which can be transferred to existing natural gas pipeline networks, such as in the Lower 48 states.

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, 2007. No difference exists between our estimated total proved reserves for year-end 2006 and year-end 2005, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2007.

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DELIVERY COMMITMENTS

We sell crude oil and natural gas from our E&P producing operations under a variety of contractual arrangements, some of which specify the delivery of a fixed and determinable quantity. Our Commercial organization also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be the spot market, or a combination of our reserves and the spot market. Worldwide, we are contractually committed to deliver approximately 5.0 trillion cubic feet of natural gas and 115 million barrels of crude oil in the future, including approximately 1 trillion cubic feet related to the minority interests of consolidated subsidiaries. These contracts have various expiration dates through the year 2025. Although these delivery commitments could be fulfilled utilizing proved reserves in the United States, Canada, the Timor Sea, Nigeria, Indonesia, and the United Kingdom, we anticipate that some of them will be fulfilled with purchases in the spot market. A portion of our commitments relate to proved undeveloped reserves. See the disclosure on Proved Undeveloped Reserves in Management s Discussion and Analysis of Financial Condition and Results of Operations for information on the development of proved undeveloped reserves.

MIDSTREAM

At December 31, 2007, our Midstream segment represented 1 percent of ConocoPhillips total assets, while contributing 4 percent of net income.

Our Midstream business is primarily conducted through our 50 percent equity investment in DCP Midstream, LLC. DCP Midstream is a joint venture with Spectra Energy.

The Midstream business purchases raw natural gas from producers and gathers natural gas through extensive pipeline gathering systems. The gathered natural gas is then processed to extract natural gas liquids. The remaining residue gas is marketed to electrical utilities, industrial users, and gas marketing companies. Most of the natural gas liquids are fractionated separated into individual components like ethane, butane and propane and marketed as chemical feedstock, fuel, or blendstock. Total natural gas liquids extracted in 2007, including our share of DCP Midstream, was 211,000 barrels per day, compared with 209,000 barrels per day in 2006.

DCP Midstream markets a portion of its natural gas liquids to ConocoPhillips and Chevron Phillips Chemical Company LLC (a joint venture between ConocoPhillips and Chevron Corporation) under a supply agreement that continues until December 31, 2014. This purchase commitment is on an if-produced, will-purchase basis and so it 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. Under this 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, 2007, DCP Midstream owned or operated 53 natural gas liquids extraction plants, 10 natural gas liquids fractionation plants, and its gathering and transmission systems included approximately 58,000 miles of pipeline. In 2007, DCP Midstream s raw natural gas throughput averaged 5.9 billion cubic feet per day, and natural gas liquids extraction averaged 363,000 barrels per day, compared with 6.0 billion cubic feet per day and 360,000 barrels per day in 2006. DCP Midstream s assets are primarily located in the following producing regions: Rocky Mountains, Midcontinent, Permian, East Texas/North Louisiana, South Texas, Central Texas, and the Gulf Coast.

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Outside of DCP Midstream, our U.S. natural gas liquids business included the following assets as of December 31, 2007:

A 50 percent interest in a natural gas liquids extraction plant in San Juan County, New Mexico. Our net share of plant inlet capacity is 275 million cubic feet per day. Effective January 1, 2008, our interest in this plant was moved to the E&P segment for reporting purposes.

A 25,000-barrel-per-day capacity natural gas liquids fractionation plant in Gallup, New Mexico.

A 22.5 percent equity interest in Gulf Coast Fractionators, which owns a natural gas liquids fractionation plant in Mont Belvieu, Texas (with our net share of capacity at 25,000 barrels per day).

A 40 percent interest in a fractionation plant in Conway, Kansas (with our net share of capacity at 42,000 barrels per day).

A 12.5 percent equity interest in a fractionation plant in Mont Belvieu, Texas (with our net share of capacity at 26,000 barrels per day).

We also own a 39 percent equity interest in Phoenix Park Gas Processors Limited (Phoenix Park), a joint venture primarily with the National Gas Company of Trinidad and Tobago Limited. Phoenix Park processes gas in Trinidad and markets natural gas liquids throughout the Caribbean and into the U.S. Gulf Coast. Its facilities include a 1.35-billion-cubic-feet-per-day gas processing plant and a 70,000-barrels-per-day natural gas liquids fractionator. Our share of natural gas liquids extracted averaged 7,800 barrels per day in 2007, compared with 6,400 barrels per day in 2006. Our share of fractionated liquids averaged 12,800 barrels per day in 2007, compared with 12,700 barrels per day in 2006.

ConocoPhillips was a party to a service contract related to the gathering, processing and transporting of natural gas in the Deir Ez Zor region of eastern Syria with the Syrian Petroleum Company that expired December 31, 2005. In 2006, we ended our presence in Syria and have no continuing operations or personnel in Syria. During 2007, we worked toward the resolution of certain immaterial claims that remain outstanding associated with our former operations there. Additionally, as part of our global crude oil supply and trading operations and consistent with applicable laws and policies of the United States and other countries in which we operate, we have purchased, and may continue to purchase, immaterial amounts of Syrian crude oil and blendstocks as feedstock for our global refining operations.

REFINING AND MARKETING (R&M)

At December 31, 2007, our R&M segment represented 21 percent of ConocoPhillips total assets, while contributing 50 percent of net income. The R&M segment contributed 29 percent of net income in 2006. R&M s percent of consolidated net income in 2007 was higher than normal due to a significant impairment recorded in the E&P segment.

R&M operations encompass refining crude oil and other feedstocks into petroleum products (such as gasoline, distillates and aviation fuels); buying, selling and transporting crude oil; and buying, transporting, distributing and marketing petroleum products. R&M has operations in the United States, Europe and Asia Pacific. The R&M segment does not include the results or statistics from our equity investment in LUKOIL, which are reported in a separate segment (LUKOIL Investment).

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

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UNITED STATES

Refining

At December 31, 2007, we owned or had an interest in 12 crude oil refineries in the United States, having an aggregate crude oil throughput capacity of 2,037,000 barrels per day net to ConocoPhillips. We are the operator of all 12 refineries.

Refinery	Location		Region	Net Crude Throughput Capacity (MB/D) At December 31 2007	Effective January 1 2008
Bayway	Linden	New Jersey	East Coast	238	238
Trainer	Trainer	Pennsylvania	East Coast	185	185
				423	423
Alliance	Belle Chasse	Louisiana	Gulf Coast	247	247
Lake Charles	Westlake	Louisiana	Gulf Coast	239	239
Sweeny	Old Ocean	Texas	Gulf Coast	247	247
				733	733
Wood River	Roxana	Illinois	Central	153	153
Borger	Borger	Texas	Central	124	95*
Ponca City	Ponca City	Oklahoma	Central	187	187
				464	435
Billings	Billings	Montana	West Coast	58	58
Ferndale	Ferndale	Washington	West Coast	100	100
Los Angeles	Carson/Wilmington	California	West Coast	139	139
San Francisco	Arroyo Grande/ San Francisco	California	West Coast	120	120
				417	417
				2,037	2,008

**Amount reflects our 65 percent share of the Borger refinery effective January 1, 2008.*

We had an 85 percent share of the Borger refinery in 2007.

East Coast Region

Bayway Refinery

The Bayway refinery is located on the New York Harbor in Linden, New Jersey. The refinery has a crude oil processing capacity of 238,000 barrels per day, and processes mainly light, low-sulfur crude oil. Crude oil is supplied to the refinery by tanker, primarily from the North Sea, Canada and West Africa. The refinery produces a high percentage of transportation fuels, such as gasoline, ultra-low-sulfur diesel and jet fuel. Other products include petrochemical feedstocks, home heating oil and residual fuel oil. The facility distributes its refined products to East Coast customers by pipeline, barge, railcar and truck. The complex also includes a 775-million-pound-per-year polypropylene plant.

Trainer Refinery

The Trainer refinery is located on the Delaware River in Trainer, Pennsylvania. The refinery has a crude oil processing capacity of 185,000 barrels per day, and processes mainly light, low-sulfur crude oil. The Bayway and Trainer refineries are operated in coordination with each other by sharing crude oil cargoes and often moving feedstocks between the facilities. Trainer receives a majority of its crude oil by tanker from West Africa, Canada and the North Sea. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel. Other products include home heating oil, residual fuel oil and liquefied petroleum gas. Refined products are primarily distributed to customers in Pennsylvania, New York and New Jersey by pipeline, barge, railcar and truck.

Gulf Coast Region

Alliance Refinery

The Alliance refinery is located on the Mississippi River in Belle Chasse, Louisiana. The refinery has a crude oil processing capacity of 247,000 barrels per day, and processes mainly light, low-sulfur crude oil. Alliance receives domestic crude oil from the Gulf of Mexico via pipeline, and foreign crude oil from the North Sea and West Africa via pipeline connected to the Louisiana Offshore Oil Port. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel. Other products include home heating oil, petrochemical feedstocks and anode petroleum coke. The majority of the refined products are distributed to customers in the southeastern and eastern United States through major common-carrier pipeline systems and by barge.

Lake Charles Refinery

The Lake Charles refinery is located in Westlake, Louisiana. The refinery has a crude oil processing capacity of 239,000 barrels per day, and processes mainly heavy, high-sulfur crude oil, but also processes low-sulfur and acidic crude oil. The refinery receives domestic and foreign crude oil, with a majority of its foreign crude oil being heavy Venezuelan and Mexican crude oil, both delivered via tanker. The refinery produces a high percentage of transportation fuels, such as gasoline, off-road diesel and jet fuel, along with home heating oil. The majority of its refined products are distributed to customers by truck, railcar, barge or major common-carrier pipelines to customers in the southeastern and eastern United States. In addition, refined products can be sold into export markets through the refinery s marine terminal.

The Lake Charles facilities include a specialty coker and calciner that manufacture graphite petroleum coke, which is supplied to the steel industry. The coker and calciner also provide a substantial increase in light oils production by breaking down the heaviest part of the crude barrel to allow additional production of diesel fuel and gasoline.

Sweeny Refinery

The Sweeny refinery is located in Old Ocean, Texas. The refinery has a crude oil processing capacity of 247,000 barrels per day. The refinery processes both heavy, high-sulfur crude oil, the majority of which is sourced from Venezuela, and light, low-sulfur crude oil. The refinery primarily receives crude oil via tankers through its 100-percent-owned and jointly owned terminals on the Gulf Coast, including a deepwater terminal at Freeport, Texas. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel. Other products include home heating oil, petrochemical feedstocks and petroleum (fuel) coke. Refined products are distributed throughout the midwest and southeast United States by pipeline, barge, railcar and truck.

ConocoPhillips has a 50 percent interest in Merey Sweeny, L.P., a limited partnership that owns a 70,000-barrel-per-day delayed coker and related facilities at the Sweeny refinery that produce fuel-grade petroleum coke. PDVSA, which owns the other 50 percent interest, supplies the refinery with heavy, high-sulfur crude oil. We are the operator and managing partner.

Central Region

EnCana Joint Venture

In October 2006, we announced a business venture with EnCana Corporation (EnCana), to create an integrated North American heavy-oil business. The transaction closed on January 3, 2007. The venture consists of two 50/50 business ventures, a Canadian upstream general partnership, FCCL Oil Sands Partnership, and a U.S. downstream limited liability company, WRB Refining LLC (WRB). We use the equity method of accounting for our investments in both entities.

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. The joint venture has expanded the processing capability of heavy Canadian crude to 95,000 barrels per day from 60,000 barrels per day with the startup of a new coker at Borger. With the completion of the Wood River coker and refinery expansion project, anticipated in 2011, we expect the capability to grow to 225,000 barrels per day. Further expansion of both Wood River and Borger are expected to provide the ultimate capability to process 550,000 barrels per day. For the Wood River refinery, operating results are shared 50/50. 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.

See the Exploration and Production (E&P) section for additional information on the upstream venture.

Wood River Refinery

The Wood River refinery is located on the east side of the Mississippi River in Roxana, Illinois. It has a crude oil processing capacity of 306,000 barrels per day, and our net share of this capacity at December 31, 2007, was 153,000 barrels per day. The refinery processes a mix of both light, low-sulfur and heavy, high-sulfur crude oil. The refinery receives domestic and foreign crude oil by various pipelines. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel. Other products include petrochemical feedstocks and asphalt. Through an off-take agreement, a significant portion of its gasoline and diesel is sold to a third party for delivery via pipelines into the upper Midwest, including the Chicago, Illinois, and Milwaukee, Wisconsin, metropolitan areas. The remaining refined products are distributed to customers in the Midwest by pipeline, truck, barge and railcar.

In early 2007, the refinery completed the construction and startup of a facility utilizing proprietary sulfur removal technology for the production of low-sulfur gasoline.

Borger Refinery

The Borger refinery is located in Borger, Texas, and the complex includes a natural gas liquids fractionation facility. The crude oil processing capacity of the refinery is 146,000 barrels per day, and the natural gas liquids fractionation capacity is 45,000 barrels per day. Our net share of the crude oil capacity at December 31, 2007, was 124,000 barrels per day. The refinery processes mainly light, high-sulfur and medium, high-sulfur crude oil. It receives crude oil and natural gas liquids feedstocks through pipelines from West Texas, the Texas Panhandle and Wyoming. The Borger refinery also receives foreign crude oil via pipeline. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel, along with a variety of natural gas liquids and solvents. Refined products are transported via pipelines from the refinery to West Texas, New Mexico, Colorado, and the Midcontinent region.

In the second quarter of 2007, construction was completed on a 25,000-barrel-per-day coker and a new vacuum unit along with revamps of heavy oil and distillate hydrotreaters. These projects allow the refinery to comply with clean fuel regulations for ultra-low-sulfur diesel and low-sulfur gasoline, as well as comply with required reductions of sulfur dioxide emissions. Additional project benefits include improved operating performance by adding additional upgrading capability, improved utilization, and the capability to process heavy Canadian crude oil.

Ponca City Refinery

The Ponca City refinery is located in Ponca City, Oklahoma. The refinery has a crude oil processing capacity of 187,000 barrels per day. The refinery processes a mixture of light, medium and heavy crude oil. Most of the crude processed is received by pipeline from the Gulf of Mexico, Oklahoma, Kansas, Texas and Canada. The refinery produces high ratios of low-sulfur gasoline and ultra-low-sulfur diesel fuel from crude oil. Finished petroleum products are primarily shipped by company-owned and common carrier pipelines to markets throughout the Midcontinent region.

West Coast Region

Billings Refinery

The Billings refinery is located in Billings, Montana. The refinery has a crude oil processing capacity of 58,000 barrels per day, and processes a mixture of Canadian heavy, high-sulfur crude oil, plus domestic high-sulfur and low-sulfur crude oil, all delivered by pipeline. A delayed coker converts heavy, high-sulfur residue into higher value light oils. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and aviation fuels, as well as fuel-grade petroleum coke. Finished petroleum products from the refinery are delivered by pipeline, railcar and truck. Pipelines transport most of the refined products to markets in Montana, Wyoming, Utah and Washington.

Ferndale Refinery

The Ferndale refinery is located on Puget Sound in Ferndale, Washington. During 2007, the refinery completed a project to expand the crude unit capacity by replacing piping and modifying various equipment. This project increased capacity by 4,000 barrels per day to 100,000 barrels per day, effective July 1, 2007. The refinery primarily receives light, low-sulfur crude oil from the Alaskan North Slope, as well as crude oil from Canada. The refinery produces transportation fuels such as gasoline and diesel. Other products include residual fuel oil supplying the northwest marine transportation market. Most refined products are distributed by pipeline and barge to major markets in the northwest United States.

Los Angeles Refinery

The Los Angeles refinery is composed of two linked facilities located about five miles apart in Carson and Wilmington, California. Carson serves as the front-end of the refinery by processing crude oil, and Wilmington serves as the back-end by upgrading products. The refinery has a crude oil processing capacity of 139,000 barrels per day, and processes mainly heavy, high-sulfur crude oil. The refinery receives domestic crude oil via pipeline from California, and both foreign and domestic crude oil by tanker through a third-party terminal in the Port of Long Beach. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel. Other products include fuel-grade petroleum coke. The refinery produces California Air Resources Board (CARB) gasoline by blending ethanol to meet government-mandated oxygenate requirements. Refined products are distributed to customers in Southern California, Nevada and Arizona by pipeline and truck.

San Francisco Refinery

The San Francisco refinery is composed of two linked facilities located about 200 miles apart. The Santa Maria facility is located in Arroyo Grande, California, about 200 miles south of San Francisco, while the Rodeo facility is in the San Francisco Bay area. The refinery has a crude oil processing capacity of 120,000 barrels per day. The refinery processes mainly heavy, high-sulfur crude oil, which is received by pipeline in California and by tanker from foreign and domestic sources. Semi-refined liquid products from the Santa Maria facility are sent by pipeline to the Rodeo facility for upgrading into finished petroleum

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products. The Rodeo facility has a calciner which upgrades a portion of the coke that is produced. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel. It also produces CARB gasoline by blending ethanol to meet government-mandated oxygenate requirements. The majority of the refined products are distributed by pipeline, railcar, truck and barge to customers in California.

Marketing

In the United States, R&M markets gasoline, diesel fuel, and aviation fuel through approximately 8,750 outlets in 49 states. The majority of these sites utilize the Conoco, Phillips 66 or 76 brands.

Wholesale

In our wholesale operations, we utilize a network of marketers and dealers operating approximately 7,750 outlets that provide refined product off-take from our operated refineries. A strong emphasis is placed on the wholesale channel of trade because of its lower capital requirements. We also buy and sell petroleum products in the spot market. Our refined products are marketed on both a branded and unbranded basis.

In addition to automotive gasoline and diesel fuel, we produce and market aviation gasoline, which is used by smaller, piston-engine aircraft. Aviation gasoline and jet fuel are sold through independent marketers at approximately 590 Phillips 66 branded locations in the United States.

Retail

In our retail operations, we own and operate 330 sites under the Phillips 66, Conoco and 76 brands. Company-operated retail operations are focused in 10 states, mainly in the Midcontinent, Rocky Mountain and West Coast regions. Most of these outlets market merchandise through the Kicks, Breakplace or Circle K brand convenience stores.

At December 31, 2007, CFJ Properties, our 50/50 joint venture with Flying J, owned and operated approximately 110 truck travel plazas that carry the Conoco and/or Flying J brands.

In December 2006, we announced our U.S. company-owned and company-operated retail outlets, and our U.S. company-owned and dealer-operated retail outlets, were expected to be divested to new or existing wholesale marketers. We sold 54 sites during 2007, and 766 company- and dealer-operated sites were classified as held for sale at December 31, 2007. We expect to complete the disposition of our U.S. retail assets in 2008.

Transportation

Pipelines and Terminals

At December 31, 2007, we had approximately 28,000 miles of common-carrier crude oil, raw natural gas liquids, and petroleum products pipeline systems in the United States, including those partially owned and/or operated by affiliates. We also owned and/or operated 51 finished product terminals, seven liquefied petroleum gas terminals, five crude oil terminals and one coke exporting facility.

In December 2007, we acquired a 50 percent equity interest in the Keystone Oil Pipeline (Keystone) to form a 50/50 joint venture with TransCanada Corporation. This joint venture plans to construct a 2,148-mile crude oil pipeline originating in Hardisty, Alberta, with delivery points at Wood River and Patoka, Illinois, and Cushing, Oklahoma. Keystone is designed to have a daily capacity of 590,000 barrels and has received binding, firm commitments from credit-worthy shippers for 495,000 barrels per day of the planned pipeline capacity, of which we have a portion. Subject to receipt of regulatory approvals, initial deliveries for Keystone s first segment are projected for late 2009, and the second segment is expected to be fully operational in the first half of 2011. We expect to utilize the Keystone pipeline to transport our Canadian crude oil production to market, including as a source of supply to WRB.

Tankers

At December 31, 2007, we had under charter 18 double-hulled crude oil tankers, with capacities ranging in size from 650,000 to 1,100,000 barrels. These tankers are utilized to transport feedstocks to certain of our U.S. refineries. The information above excludes the operations of the company s subsidiary, Polar Tankers, Inc., which is discussed in the E&P segment overview, as well as an owned tanker on lease to a third party for use in the North Sea.

Several transportation assets were sold during 2007, including the domestic marine inland barge and vessel operations, the Grand Junction terminal, the Bettendorf terminal, and the Kapalama pipeline. Negotiations to sell the international marine operations leasehold interest in six international tankers were under way in 2007, and this sale was completed in January 2008.

Specialty Businesses

We manufacture and sell a variety of specialty products including petroleum cokes, lubes (such as automotive and industrial lubricants), solvents, and pipeline flow improvers to commercial, industrial and wholesale accounts worldwide.

Lubricants are marketed under the Conoco, Phillips 66, 76 Lubricants and Kendall Motor Oil brands. The distribution network includes mass merchandise stores, fast lubes, tire stores, automotive dealers and convenience stores. Lubricants are also sold to industrial customers in many markets.

The company s 50 percent-owned Excel Paralubes joint venture owns a hydrocracked lubricant base oil manufacturing plant located adjacent to the Lake Charles refinery. The facility produces approximately 20,000 barrels per day of high-quality, clear hydrocracked base oils. Hydrocracked base oils are second in quality only to synthetic base oils, but are produced at a much lower cost. The Lake Charles refinery supplies Excel Paralubes with a portion of its gas-oil feedstocks. We purchase 50 percent of the joint venture s output, and blend the base oil into finished lubricants or market it to third parties.

We also manufacture high-quality graphite and anode-grade cokes in the United States and Europe for use in the global steel and aluminum industries.

During 2007, our Specialty Businesses operations sold its Conostan calibration fluid technology.

Additionally, as of December 31, 2007, we had a 50 percent interest in Penreco, which manufactures and markets highly refined specialty petroleum products, including solvents, waxes, petrolatums and white oils, for global markets. In January 2008, we sold our interest in Penreco.

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INTERNATIONAL

Refining

At December 31, 2007, R&M owned or had an interest in five refineries outside the United States with an aggregate crude oil capacity of 669,000 barrels per day net to ConocoPhillips.

Refinery	Location		Ownership Interest	Net Crude Throughput Capacity (MB/D) At December 31 2007	Effective January 1 2008
Humber	N. Lincolnshire	United Kingdom	100.00%	221	221
Whitegate	Cork	Ireland	100.00	71	71
Wilhelmshaven	Wilhelmshaven	Germany	100.00	260	260
MiRO	Karlsruhe	Germany	18.75	57	58
Melaka	Melaka	Malaysia	47.00	60	60
				669	670

Humber Refinery

The Humber refinery is located in North Lincolnshire, United Kingdom. The refinery s crude oil processing capacity is 221,000 barrels per day. Crude oil processed at the refinery is supplied primarily from the North Sea and includes light, low-sulfur and acidic crude oil. The refinery also processes intermediate feedstocks, mostly vacuum gas oils and residual fuel oil.

The Humber refinery is a fully integrated refinery that produces a high percentage of transportation fuels, such as gasoline and diesel. Other products include home heating oil and specialty chemicals. The refinery also has two coking units with associated calcining plants, which upgrade the heaviest part of the crude barrel and imported feedstocks into light-oil products and graphite and anode petroleum cokes. Products produced in the refinery are marketed in the United Kingdom, along with the rest of Europe and the United States.

Whitegate Refinery

The Whitegate refinery in Cork, Ireland, has a crude oil processing capacity of 71,000 barrels per day. Crude oil processed by the refinery is light, low-sulfur crude oil sourced mostly from the North Sea. The refinery primarily produces transportation fuels, such as gasoline, diesel and fuel oil, which are distributed to the inland market, as well as being exported to Europe and the United States. We also operate a crude oil and products storage complex consisting of 7.5 million barrels of storage capacity and an offshore mooring buoy, located in Bantry Bay, about 80 miles southwest of the Whitegate refinery in southern Cork County.

Wilhelmshaven Refinery

The Wilhelmshaven refinery is located in the northern state of Lower Saxony in Germany, and has a crude oil processing capacity of 260,000 barrels per day. Crude oil processed by the refinery is low-sulfur sourced mostly from the North Sea. The Wilhelmshaven refinery mainly produces transportation fuels, fuel oil, and intermediate feedstocks, which are primarily exported to Europe and the United States, but are also distributed to the inland market via truck and rail. Additionally, we operate a marine terminal, rail and truck loading facilities and a tank farm. We have evaluated alternatives to economically improve the operation of the refinery and have incorporated a deep conversion plan into our capital budget.

MiRO Refinery

The Mineraloel Raffinerie Oberrhein GmbH (MiRO) refinery in Karlsruhe, Germany, is a joint-venture refinery with a crude oil processing capacity of 307,000 barrels per day. Effective January 1, 2008, the refinery s capacity was increased by 5,000 barrels per day due to incremental debottlenecking, with our share being an increase of 1,000 barrels per day. We have an 18.75 percent interest in MiRO, giving us a net capacity share of 58,000 barrels per day. The refinery s crude oil feedstock includes medium-sulfur crude oil. The MiRO complex is a fully integrated refinery producing gasoline, middle distillates and specialty products, along with a small amount of residual fuel oil. The refinery has a high capacity to convert lower-cost feedstocks into higher-value products, primarily with a fluid catalytic cracker and a delayed coker. The refinery also produces fuel-grade and specialty calcined cokes. The refinery processes crude and other feedstocks supplied by each of the co-venturers in proportion to their respective ownership interests. The majority of refined products are distributed by truck and railcar to Germany and neighboring markets.

Melaka Refinery

The refinery in Melaka, Malaysia, is a joint-venture refinery in which we own a 47 percent interest. The refinery has a rated crude oil processing capacity of 128,000 barrels per day, of which our share is 60,000 barrels per day. The medium, high-sulfur crude oil processed by the refinery is sourced mostly from the Middle East. The refinery produces a full range of refined petroleum products. The refinery capitalizes on our proprietary coking technology to upgrade low-cost feedstocks to higher-margin products. Our share of refined products is transported by tanker and marketed in Malaysia and other Asian markets.

In late 2007, we and our co-venturers sanctioned a project for the planned expansion of the refinery due for completion in early 2010. This project is intended to increase crude oil, conversion and treating unit capacities.

Other

In May 2006, we signed a Memorandum of Understanding with Saudi Aramco to conduct a detailed evaluation of the proposed development of a 400,000-barrel-per-day, full-conversion refinery in Yanbu, Saudi Arabia. The refinery would be designed to process Arabian heavy crude oil and produce high-quality, ultra-low-sulfur refined products. A joint ConocoPhillips and Saudi Aramco project team has initiated work on the front-end engineering design study. This study, as well as an evaluation of project financing and negotiations of key commercial agreements, is scheduled to be completed later in 2008.

In July 2006, we announced the signing of a Memorandum of Understanding with International Petroleum Investment Company (IPIC) of Abu Dhabi to identify new upstream and downstream opportunities for joint investment. A feasibility study for construction of a 500,000-barrel-per-day refinery in Fujairah, United Arab Emirates, was completed in 2007. ConocoPhillips decided not to proceed with this joint-investment opportunity.

Our 16.33 percent ownership interest in Česká Rafinérská, a.s. (CRC), consisting of two refineries located in the Czech Republic, was sold during 2007.

Marketing

At December 31, 2007, R&M had marketing operations in eight European countries. R&M s European marketing strategy is to sell primarily through owned, leased or joint-venture retail sites using a low-cost, high-volume strategy. 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.

We use the JET brand name to market retail and wholesale products in Austria, Denmark, Germany, Norway, Sweden and the United Kingdom. In addition, a joint venture in which we have an equity

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interest markets products in Switzerland under the Coop brand name. We also sell a portion of our Ireland refinery output to inland Irish markets.

As of December 31, 2007, R&M had approximately 1,600 marketing outlets in its European operations, of which approximately 1,150 were company-owned, and 450 were dealer-owned. Through our joint-venture operations in Switzerland, we also have interests in 196 additional sites. The company s largest branded site networks are in Germany and the United Kingdom, which account for approximately 75 percent of our total European branded units. During 2007, we sold 377 of our fueling stations in six European countries to LUKOIL and completely divested our marketing operations in Thailand and Malaysia. As of December 31, 2007, agreements were signed for the sale of Norway, Sweden and Denmark marketing assets. We expect to complete the disposition of these assets in 2008.

LUKOIL INVESTMENT

At December 31, 2007, our LUKOIL Investment segment represented 6 percent of ConocoPhillips total assets, while contributing 15 percent of net income.

In September 2004, we made a joint announcement with LUKOIL, an international integrated oil and gas company headquartered in Russia, of an agreement to form a broad-based strategic alliance, whereby we would become a strategic equity investor in LUKOIL. By year-end 2005, we had an ownership interest in LUKOIL of 16.1 percent. At December 31, 2006 and 2007, we had a 20 percent ownership interest, based on issued shares, and a 20.6 percent ownership interest, based on estimated shares outstanding. See Note 10 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for additional information.

Under the Shareholder Agreement between the two companies, we have representation on the LUKOIL Board of Directors (Board), and LUKOIL s corporate charter requires unanimous Board consent for certain key decisions. In addition, the Shareholder Agreement limits our ownership interest in LUKOIL to 20 percent, based on authorized and issued shares, and limits our ability to sell our LUKOIL shares for a period of four years from September 29, 2004, except in certain circumstances. We use the equity method of accounting for our investment in LUKOIL.

As reported in LUKOIL s 2006 annual report, the majority of its 2006 upstream oil production was sourced within Russia, with 63 percent from the western Siberia region, 14 percent from the Timan-Pechora province and 12 percent from the Urals region. Outside of Russia, LUKOIL had oil production in 2006 in Kazakhstan, Egypt, and Azerbaijan, and gas production in Uzbekistan. Ninety-one percent of LUKOIL s natural gas production was sourced within Russia. In addition, LUKOIL has an active exploration program focused in Russia, but also encompassing several other international countries. Downstream, LUKOIL has seven refineries with a net crude oil throughput capacity of approximately 1.2 million barrels per day. In addition, LUKOIL has a marketing network which extends to 19 countries, with the majority of wholesale and retail sales in Russia, the United States and Europe.

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CHEMICALS

At December 31, 2007, our Chemicals segment represented 1 percent of ConocoPhillips total assets, while contributing 3 percent of net income.

The Chemicals segment consists of our 50 percent equity investment in Chevron Phillips Chemical Company LLC (CPChem), a joint venture with Chevron Corporation. CPChem is headquartered in The Woodlands, Texas. CPChem s business is structured around three primary operating segments: Olefins & Polyolefins, Aromatics & Styrenics, and Specialty Products. The Olefins & Polyolefins segment produces and markets ethylene, propylene, and other olefin products, which are primarily consumed within CPChem for the production of polyethylene, normal alpha olefins, polypropylene, and polyethylene pipe. The Aromatics & Styrenics segment manufactures and markets aromatics products, such as benzene, styrene, paraxylene and cyclohexane. This segment also manufactures and markets polystyrene, as well as styrene-butadiene copolymers. The Specialty Products segment manufactures and markets a variety of specialty chemical products, including organosulfur chemicals, solvents, catalysts, drilling chemicals, mining chemicals and high-performance engineering plastics and compounds.

CPChem s domestic production facilities are located at Baytown, Borger, Conroe, La Porte, Orange, Pasadena, Port Arthur and Old Ocean, Texas; St. James, Louisiana; Pascagoula, Mississippi; Marietta, Ohio; and Guayama, Puerto Rico. CPChem also has one pipe fittings production plant and eight plastic pipe production plants in eight states. Major international production facilities are located in Belgium, China, Saudi Arabia, Singapore, South Korea and Qatar. CPChem has research and technical facilities in Oklahoma, Ohio and Texas, as well as in Singapore and Belgium.

CPChem owns a 49 percent interest in a joint-venture company, Qatar Chemical Company Ltd. (Q-Chem), that owns a major olefins and polyolefins complex in Mesaieed, Qatar. CPChem also owns a 49 percent interest in Qatar Chemical Company II Ltd. (Q-Chem II), a joint venture that began construction of a second complex in Mesaieed in 2005. This Q-Chem II facility is designed to produce polyethylene and normal alpha olefins on a site adjacent to the Q-Chem complex. In connection with this project, CPChem and Qatar Petroleum entered into a separate agreement with Total Petrochemicals and Qatar Petrochemical Company Ltd., establishing a joint venture to develop an ethylene cracker in Ras Laffan Industrial City, Qatar. The cracker will provide ethylene feedstock via pipeline to the Q-Chem II plants. Operational startup of the Q-Chem II projects is anticipated in the second quarter of 2009.

In 2003, CPChem formed a 50-percent-owned joint venture company to develop an integrated styrene facility in Al Jubail, Saudi Arabia. The facility, being built on a site adjacent to the existing aromatics complex owned by Saudi Chevron Phillips Company (SCP), another 50-percent-owned CPChem joint venture, will include feed fractionation, an olefins cracker, and ethylbenzene and styrene monomer processing units. Construction of the facility, which began in the fourth quarter of 2004, is in conjunction with an expansion of SCP s existing benzene plant, together called the JCP Project. Operational startup is anticipated in mid-2008.

In 2007, CPChem formed a 50-percent-owned joint venture company, Saudi Polymers Company, to construct and operate an integrated petrochemicals complex at Al Jubail, Saudi Arabia. The facility 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. Prior to project completion, CPChem s ownership interest in the joint venture is expected to decline to 35 percent.

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In 2007, CPChem and the Dow Chemical Company signed a non-binding Memorandum of Understanding relating to the formation of a joint venture involving assets from their polystyrene and styrene monomer businesses in the Americas. Upon formation of the joint venture, CPChem intends to contribute its styrene monomer plant in St. James, Louisiana, and its polystyrene plant in Marietta, Ohio, and Dow intends to contribute six polystyrene plants. The new venture is subject to customary regulatory review, due diligence, completion of definitive agreements, and corporate and other approvals. Joint-venture operations are expected to commence in the first half of 2008.

EMERGING BUSINESSES

At December 31, 2007, our Emerging Businesses segment represented 1 percent of ConocoPhillips total assets. Emerging Businesses encompass the development of new technologies and businesses outside our normal scope of operations.

Power Generation

The focus of our power business is on developing integrated projects to support the company s E&P and R&M strategies and business objectives. The projects that are primarily in place to enable these strategies are included within their respective E&P and R&M segments. The power projects and assets that have a significant merchant component are included in the Emerging Businesses segment.

The Immingham combined heat and power (CHP) plant, a wholly owned 730-megawatt, gas-fired facility in North Lincolnshire, United Kingdom, provides steam and electricity to the Humber refinery and steam to a neighboring refinery, as well as merchant power into the U.K. market.

In October 2006, we announced we would invest approximately $400 million to expand the capacity at our Immingham CHP plant by 450 megawatts to 1,180 megawatts. Development work on Immingham Phase 2 began with the award of a contract for front-end engineering and securing of additional connection availability to the U.K. grid. Commercial operation of the expansion is expected to start in mid-2009.

We also own a gas-fired cogeneration plant in Orange, Texas.

In October 2007, we purchased a 50 percent operating interest in Sweeny Cogeneration LP (SCLP). SCLP provides steam and electric power to the Sweeny refinery complex with any excess power sold into the market. We account for this joint venture using the equity method of accounting.

Carbon-to-liquids

We are expanding our efforts to develop carbon-to-liquids technology focused on coal and petroleum coke.

Alternative Energy and Technology Programs

Alternative Energy and Technology Programs focuses on developing new business opportunities designed to provide growth options for ConocoPhillips well into the future. Example areas of interest include advanced hydrocarbon processes, energy conversion technologies, new petroleum-based products, and renewable fuels. ConocoPhillips is interested in the production of biofuels. We have recently commercialized the production of renewable diesel, a new type of renewable fuel that utilizes existing infrastructure. In 2007, we formed a research relationship with Iowa State University to develop new methods for producing second-generation biofuels. We also formed alliances with Tyson Foods and Archer Daniels Midland to produce and market the next generation of renewable transportation fuels.

Coal-to-gas

We offer a gasification technology (E-Gas™) that uses petroleum coke, coal, and other low-value hydrocarbons as feedstock, resulting in high-value synthetic gas used for a slate of products, including power, hydrogen and chemicals.

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In 2007, we entered into an agreement with Peabody Energy to perform a feasibility study for the development of a coal-to-gas facility using proprietary ConocoPhillips E-Gas™ technology. If constructed, the facility would be developed at a location where Peabody has access to coal reserves and existing infrastructure. The feasibility study and preliminary design are expected to continue into 2008.

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 the segments in which we operate is highly competitive. No single competitor, or small group of competitors, dominates any of our business lines.

Upstream, our E&P segment competes with numerous other companies in the industry 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 2006 reserves statistics, we had, on a BOE basis, the sixth-largest total of worldwide proved reserves of non-government-controlled companies. We deliver our oil and natural gas production into the worldwide oil and natural gas commodity markets. The principal methods of competing include geological, geophysical and engineering research and technology; experience and expertise; economic analysis in connection with property acquisitions; and operating efficient oil and gas producing properties.

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

Downstream, our R&M segment competes primarily in the United States, Europe and the Asia Pacific region. Based on the statistics published in the December 24, 2007, issue of the *Oil & Gas Journal*, our R&M segment had the second-largest U.S. refining capacity of 16 large refiners of petroleum products. Worldwide, it ranked fifth among non-government-controlled companies. In the Chemicals segment, CPChem generally ranks within the top 10 producers of many of its major product lines, based on average 2007 production capacity, as published by industry sources. Petroleum products, petrochemicals and plastics are delivered into the worldwide commodity markets. Elements of downstream competition include product improvement, new product development, low-cost structures, and improved 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 2007, we held a total of 1,818 active patents in 72 countries worldwide, including 686 active U.S. patents. During 2007, we received 40 patents in the United States and 124 foreign patents. Our products and processes generated licensing revenues of $55 million in 2007. 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 $160 million, $117 million, and $125 million in 2007, 2006, and 2005, respectively.

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The environmental information contained in Management s Discussion and Analysis of Financial Condition and Results of Operations on pages 81 through 84 under the caption, Environmental, is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2007 and those expected for 2008 and 2009.

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 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.

A substantial or extended decline in crude oil, natural gas and natural gas liquids prices, as well as refining margins, would reduce our operating results and cash flows, and could impact our future rate of growth and the carrying value of our assets.

Prices for crude oil, natural gas and natural gas liquids fluctuate widely. Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our crude oil, natural gas, natural gas liquids and refined products. Historically, the markets for crude oil, natural gas, natural gas liquids and refined products have been volatile and may continue to be volatile in the future. The factors influencing the prices of crude oil, natural gas, natural gas liquids and refined products are beyond our control. These factors include, among others:

- Worldwide and domestic supplies of, and demand for, crude oil, natural gas, natural gas liquids and refined products.
- The cost of exploring for, developing, producing, refining and marketing crude oil, natural gas, natural gas liquids and refined products.
- Changes in weather patterns and climatic changes.
- The ability of the members of OPEC and other producing nations to agree to and maintain production levels.
- The worldwide military and political environment, uncertainty or instability resulting from an escalation or additional outbreak of armed hostilities or further acts of terrorism in the United States, or elsewhere.
- The price and availability of alternative and competing fuels.
- Domestic and foreign governmental regulations and taxes.
- Additional or increased nationalization and expropriation activities by foreign governments.
- General economic conditions worldwide.

The long-term effects of these and other conditions on the prices of crude oil, natural gas, natural gas liquids and refined products are uncertain. Generally, our policy is to remain exposed to market prices of commodities; however, management may elect to hedge the price risk of our crude oil, natural gas, natural gas liquids and refined products. Lower crude oil, natural gas, natural gas liquids and refined products prices may reduce the amount of these commodities that we can produce economically, which may reduce our revenues, operating income and cash flows. Significant reductions in commodity prices could require us to reduce capital spending, share repurchases, debt reduction, or to impair the carrying value of assets.

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Estimates of crude oil and natural gas reserves depend on many factors and assumptions, including various assumptions that are based on conditions in existence as of the dates of the estimates. Any material changes in those conditions or other factors affecting those assumptions could impair the quantity and value of our crude oil and natural gas reserves.

The proved crude oil and natural gas reserve information relating to us included in this annual report has been derived from engineering estimates prepared or reviewed by our personnel. The estimates were calculated using crude oil and natural gas prices in effect as of December 31, 2007, as well as other conditions in existence as of that date. Any significant future price changes will have a material effect on the quantity and present value of our proved reserves. Future reserve revisions could also result from changes in, among other things, governmental regulation.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of crude oil and natural gas that cannot be directly measured. Estimates of economically recoverable crude oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including:

- Historical production from the area, compared with production from other comparable producing areas.
- The assumed effects of regulations by governmental agencies.
- Assumptions concerning future crude oil and natural gas prices.
- Assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

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. Because of the subjective nature of crude oil and natural gas reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- The amount and timing of crude oil and natural gas production.
- The revenues and costs associated with that production.
- The amount and timing of future development expenditures.

The discounted future net revenues from our proved reserves should not be construed to represent fair market value. As required by rules adopted by the SEC, the estimated discounted future net cash flows from our proved reserves, as described in the supplemental oil and gas operations disclosures on pages 174 through 193, are based generally on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. In addition, the 10 percent discount factor, which SEC rules require to be used to calculate discounted future net revenues for reporting purposes, is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the crude oil and natural gas industry in general.

If we are unsuccessful in acquiring or finding additional reserves, our future crude oil and natural gas production would decline, thereby reducing our cash flows and results of operations, negatively impacting our financial condition.

The rate of production from crude oil and natural gas properties generally declines as reserves are depleted. Except to the extent that we acquire additional properties containing proved reserves, 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 decline. Creating and maintaining an inventory of projects depends on many factors, including:

- Obtaining rights to explore, develop and produce crude oil and natural gas in promising areas.
- Drilling success.
- The ability to complete long lead-time, capital-intensive projects timely and on budget.
- Efficient and profitable operation of mature properties.

We may not be able to find or acquire additional reserves at acceptable costs.

Crude oil price increases and environmental regulations may reduce our refined product margins.

The profitability of our R&M segment depends largely on the margin between the cost of crude oil and other feedstocks we refine and the selling prices we obtain for refined products. Our overall profitability could be adversely affected by the availability of supply and rising crude oil and other feedstock prices that we do not recover in the marketplace. Refined product margins historically have been volatile and vary with the level of economic activity in the various marketing areas, the regulatory climate, logistical capabilities and the available supply of refined products. In addition, environmental regulations, particularly the 1990 amendments to the Clean Air Act, have imposed, and are expected to continue to impose, increasingly stringent and costly requirements on our refining and marketing operations, which may reduce refined product margins.

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/or reduce demand for our products. As a result, our business, financial condition, results of operations and cash flows in future periods could be materially adversely affected.

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 in the United States, or potential future control of greenhouse gas emissions).
- The handling, use, storage, transportation, disposal and clean up of hazardous materials and hazardous and non-hazardous wastes.
- The dismantlement, abandonment and restoration of our properties and facilities at the end of their useful lives.

We have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of these laws and regulations. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products and services, our operating results will be adversely affected. The specific impact of these laws and regulations on us and our competitors may vary depending on a number of factors, including the age and location of operating facilities, marketing areas and production processes. We may also be required to make material expenditures to:

- Modify operations.
- Install pollution control equipment.
- Perform site cleanups.

Curtail operations.

Acquire additional non-petroleum feedstocks or compliance credits to comply with laws mandating specified percentages of biofuels in our refined products.

We may become subject to liabilities we currently do not anticipate in connection with new, amended or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination. In addition, any failure by us to comply with existing or future laws could result in civil or criminal fines and other enforcement actions against us.

Our, and our predecessors , operations also could expose us to civil claims by third parties for alleged liability resulting from contamination of the environment or personal injuries caused by releases of hazardous substances.

Environmental laws are subject to frequent change and many of them have become more stringent. In some cases, they can impose liability for the entire cost of cleanup on any responsible party, without regard to negligence or fault, and impose liability on us for the conduct of others or conditions others have caused, or for our acts that complied with all applicable requirements when we performed them.

Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Contingencies Environmental in Item 7 of this annual report for further information about environmental laws and regulations impacting our business.

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

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 63 percent of our crude oil, natural gas and natural gas liquids production in 2007 was derived from production outside the United States, and 59 percent of our proved reserves, as of December 31, 2007, were located outside the United States.

There are many risks associated with operations in international markets, including changes in foreign governmental policies relating to crude oil, natural gas, natural gas liquids or refined product pricing and taxation, other political, economic or diplomatic developments, changing political conditions and international monetary fluctuations. These risks include, among others:

Political and economic instability, war, acts of terrorism and civil disturbances.

The possibility that a foreign government may seize our property, with or without compensation, may attempt to renegotiate or revoke existing contractual arrangements and concessions, or may impose additional taxes or royalties.

Fluctuating currency values, hard currency shortages and currency controls.

Continued hostilities and turmoil in the world and the occurrence or threat of future terrorist attacks could affect the economies of the United States and other developed countries. A lower level of economic activity could result in a decline in energy consumption, which could cause our revenues and margins to decline and limit our future growth prospects. More specifically, our energy-related assets may be at greater risk of future terrorist attacks than other possible targets. A direct attack on our assets, or assets used by us, could have a material adverse effect on our operations, financial condition, results of operations and prospects. These risks could lead to increased volatility in prices for crude oil, natural gas, natural gas liquids and refined products and could increase instability in the financial and insurance markets, making it more difficult for us to access capital and to obtain the insurance coverage that we consider adequate.

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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 and will continue to do so in the future.

We also are exposed to fluctuations in foreign currency exchange rates. We do not comprehensively hedge our exposure to currency rate changes, although we may choose to selectively hedge certain working capital balances, firm commitments, cash returns from affiliates and/or tax payments. These efforts may not be successful.

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

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

Our operations are subject to business interruptions and casualty losses, and we do not insure against all potential losses, so we could be seriously harmed by unexpected liabilities.

Our exploration and production operations are subject to unplanned occurrences, including blowouts, explosions, fires, loss of well control, formations with abnormal pressures, spills and adverse weather. In addition, our refining, marketing and transportation operations are subject to business interruptions due to scheduled refinery turnarounds and unplanned events such as explosions, fires, pipeline interruptions, pipeline ruptures, crude oil or refined product spills, inclement weather or labor disputes. Our operations are also subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks, as well as hazards of marine operations, such as capsizing, collision and damage or loss from severe weather conditions. All such hazards could result in loss of human life, significant property and equipment damage, environmental pollution, impairment of operations and substantial losses to us. These hazards have adversely affected us in the past, and litigation arising from a catastrophic occurrence in the future at one of our locations may result in our being named as a defendant in lawsuits asserting potentially large claims or being assessed potentially substantial fines by governmental authorities. In addition, we are exposed to risks inherent in any business, such as terrorist attacks, equipment failures, accidents, theft, strikes, protests and sabotage, that could disrupt or interrupt operations.

We maintain insurance against many, but not all, potential losses or liabilities arising from these operating hazards in amounts that we believe to be prudent. Uninsured losses and liabilities arising from operating hazards could reduce the funds available to us for exploration, drilling, production and other capital expenditures and could materially reduce our profitability.

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 partners. Although we often enter into joint-venture arrangements in order to share risks with our joint-venture partners, these arrangements may decrease our ability to manage risk. As with any joint-venture arrangement, differences in views among the joint-venture participants may result in delayed decisions or in failures to agree on major issues. There is the risk that our joint-venture partners may at any time have economic, business or legal interests or goals that are inconsistent with those of the joint venture or us. There is also risk our joint-venture partners may be unable to meet their economic or other

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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 anticipate entering into additional joint ventures with other entities. We cannot assure that we will undertake such joint ventures or, if undertaken, that such joint ventures will be successful.

Item 1B. UNRESOLVED STAFF COMMENTS

None.

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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 previously reported in ConocoPhillips 2006 Form 10-K and our first-, second- and third-quarter 2007 Form 10-Qs that were not resolved prior to the fourth quarter of 2007. No new reportable matters arose during the fourth quarter of 2007. 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, there would be no material effect on our consolidated financial position. Nevertheless, such proceedings are reported pursuant to the U.S. Securities and Exchange Commission s 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 decree 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 decree and/or other reports required by permits or regulations, we occasionally report matters which could be subject to a request for stipulated penalties. If a specific request for stipulated penalties meeting the reporting threshold set forth in U.S. Securities and Exchange Commission 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.

Matters Previously Reported

The South Coast Air Quality Management District (SCAQMD) conducted an audit of the Los Angeles refinery to assess compliance with applicable local, state, and federal regulations related to fugitive emissions. As a result of the audit, SCAQMD issued three Notices of Violations (NOVs) alleging multiple counts of non-compliance. SCAQMD has not yet specified a penalty for these alleged violations. We are currently assessing these allegations and expect to work with SCAQMD toward a resolution of these NOVs.

In October 2007, we received a Complaint from the U.S. 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 have begun discussions with the EPA to settle this matter and will work with the agency to resolve this matter.

On September 25, 2007, the Sweeny refinery received a draft order to resolve a July 6, 2007, Notice of Enforcement (NOE) relating to alleged violations of the Texas Clean Air Act. The allegations relate to compliance with limitations contained in the refinery s Title V operating permit and one emission event.

In November 2007, we paid $114,450 as a penalty and agreed to fund a Supplemental Environmental Project (SEP) in the same amount. We anticipate approval of the settlement by the Texas Commission on Environmental Quality (TCEQ).

In June 2007, the Ferndale refinery was informed by the U.S. EPA that it will seek penalties for Ferndale s alleged failure to comply with certain portions of the Benzene Waste Operations rule. The government alleges the facility has not complied with certain equipment maintenance and inspection rules since 1993. We are working with the EPA and the Department of Justice to resolve this matter.

The Pennsylvania Department of Environmental Protection (PADEP) has informed the Trainer refinery it intends to seek penalties for acid gas flaring which occurred during April and/or May 2007. We are currently assessing this matter and expect to work with the PADEP to resolve it. Since this matter is subject to an EPA Consent Decree, we do not anticipate reporting further on this matter until we receive a specific request and if such request meets the reporting threshold.

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On April 30, 2007, the Borger refinery received an offer to settle a range of violations alleged in a March 16, 2007, NOE issued by the TCEQ. The alleged violations relate to air quality permit limits, emission events, testing requirements, and reporting or recordkeeping requirements. In November 2007, we submitted payment of a penalty of $84,900 and agreed to fund an SEP valued at $84,900. We anticipate TCEQ will approve this settlement.

In March 2007, the Sweeny refinery received a series of NOEs from the TCEQ. These NOEs generally relate to emission events such as flaring and other unplanned releases. The TCEQ proposed a penalty of $325,120 in a revised draft order received in November 2007. We paid a penalty of $162,560 and agreed to fund an SEP in the same amount upon final approval of the settlement by the TCEQ.

On February 7, 2007, Gulf Coast Fractionators, a gas processing facility operated by ConocoPhillips in which we have a 22.5 percent interest, received a draft order from the TCEQ proposing to settle alleged violations of air emission permit limits at the plant. The order proposed a penalty of $135,538. In October 2007, this matter was resolved by payment of a penalty of $67,769 and agreement to fund an SEP of $67,769. We anticipate this proposed settlement will be approved by the TCEQ.

In the fall of 2006, the Wood River refinery experienced two incidents where coker oil mist was released from the Distilling West coker. In a February 9, 2007, letter the state of Illinois demanded $50,000 for each release. We are working with the state toward a final resolution of this matter.

On March 28, 2006, the TCEQ issued a revised draft agreed order relating to alleged air quality violations at the Borger refinery. The order addresses several categories of air quality violations including emission events, violation of permit conditions, and failure to pay emission fees, and a single solid waste violation for improper classification and disposal of waste. The order proposed a penalty of $160,406. The TCEQ recalculated the penalty of $151,726. We agreed to pay a penalty of $75,863 and to fund an SEP in the same amount. The TCEQ approved this settlement and the required payments have been made.

On December 16, 2005, our Bayway refinery experienced a hydrocarbon spill to the Rahway River and Arthur Kill. As a result of this spill, we signed an Order on Consent (Order) with the state of New York, and are also negotiating similar settlements with the state of New Jersey and the federal government. Under the final New York Order, we paid a penalty of $50,000 and conducted a beach cleanup.

In December 2005, the TCEQ proposed an administrative penalty of $120,132 for alleged violations of the Texas Clean Air Act at the Borger refinery. The allegations relate to unexcused emission events, reporting and recordkeeping requirements, leak detection and repair, flare outages, and Title V permit reporting. We have paid an administrative penalty of $57,716, and agreed to perform SEPs totaling $57,716. This settlement was approved and adopted by the TCEQ at its meeting November 7, 2007, and the final SEP payment has been made.

In December 2005, routine tests at our refinery in Lake Charles, Louisiana, revealed that certain particulate matter emissions did not meet established limits. The refinery has resolved this issue and achieved full compliance with all applicable particulate matter emission limits in the first quarter of 2007. The EPA and Louisiana Department of Environmental Quality were kept informed of the refinery s remedial actions. The refinery will work with the agencies to resolve any enforcement actions that may be brought. Since this matter is subject to an EPA Consent Decree, we do not anticipate reporting further on this matter until we receive a specific request and if such request meets the reporting threshold.

In March 2005, ConocoPhillips Pipe Line Company (CPPL) received a Notice of Probable Violation and Proposed Civil Penalty from the Department of Transportation s Pipeline and Hazardous Materials Safety Administration (DOT) alleging violation of DOT operation and safety regulations at certain facilities in

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Kansas, Missouri, Illinois, Indiana, Wyoming and Nebraska. DOT is proposing penalties in the amount of $184,500. An information hearing was held on September 24, 2007. CPPL has provided additional information in support of its position. A DOT ruling is not anticipated until the first quarter of 2008.

The U.S. Coast Guard and Washington State Department of Ecology investigated the possible sources of an oil spill in Puget Sound. In November 2004, the U.S. Attorney and the U.S. Coast Guard offices in Seattle, Washington, issued subpoenas to Polar Tankers, Inc., a subsidiary of ConocoPhillips Company, for records related to the vessel Polar Texas. On December 23, 2004, the governor of the state of Washington and the U.S. Coast Guard publicly announced they believed the Polar Texas was the source of the spill. The company fully cooperated with the investigations. The U.S. Attorney s Office in Seattle declined prosecution of the company. Polar Tankers, ConocoPhillips and the state of Washington settled the matter, with payment of civil penalties in the amount of $540,000. Additionally, the company has agreed to pay the federal government $2.2 million to cover the cost of the spill cleanup, and $80,000 in civil penalties. The settlement did not include any admission of liability. The company and the authorities remain in settlement negotiations around other remaining items.

In April 2004, in response to several historic spills at the Albuquerque Products Terminal, we received an Administrative Compliance Order from the New Mexico Environment Department. The order does not propose a penalty assessment, but rather attempts to impose specific design, construction and operational changes. We have been in negotiations with the agency and have proposed a settlement offer of $100,000. We will continue to work with the agency to resolve this matter.

In August of 2003, EPA Region 6 issued a Show Cause Order alleging violations of the federal Clean Water Act at the Borger refinery. The alleged violations relate primarily to discharges of selenium and reported exceedances of permit limits for whole effluent toxicity. On April 17, 2007, the U.S. Department of Justice (DOJ) sent a draft Consent Decree (CD) proposing to settle the outstanding wastewater allegations. The draft CD proposes a penalty of $2.64 million and includes injunctive actions, some of which have already been completed by ConocoPhillips. We are working with the DOJ and EPA to resolve this matter.

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

None.

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EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Position Held	Age*
Rand C. Berney	Vice President and Controller	52
John A. Carrig	Executive Vice President, Finance, and Chief Financial Officer	56
Sigmund L. Cornelius	Senior Vice President, Planning, Strategy and Corporate Affairs	52
James L. Gallogly	Executive Vice President, Refining, Marketing and Transportation	55
Janet L. Kelly	Senior Vice President, Legal, General Counsel and Corporate Secretary	50
John E. Lowe	Executive Vice President, Exploration and Production	49
James J. Mulva	Chairman of the Board of Directors, President and Chief Executive Officer	61

**On March 1, 2008.*

There is no family relationship among the officers named above. Each officer of the company is elected by the Board of Directors at its first meeting after the Annual Meeting of Stockholders and thereafter as appropriate. Each officer of the company holds office from date of election until the first meeting of the directors held after the next Annual Meeting of Stockholders or until a successor is elected. The date of the next annual meeting is May 14, 2008. Set forth below is information about the executive officers.

Rand C. Berney was appointed Vice President and Controller of ConocoPhillips upon completion of the merger in 2002.

John A. Carrig was appointed Executive Vice President, Finance, and Chief Financial Officer of ConocoPhillips upon completion of the merger in 2002.

Sigmund L. Cornelius was appointed Senior Vice President, Planning, Strategy and Corporate Affairs of ConocoPhillips effective September 1, 2007, having previously served as ConocoPhillips President, Exploration and Production Lower 48 since 2006. He served as President, Global Gas of ConocoPhillips since 2004, and prior to that he served as ConocoPhillips President, Lower 48, Latin America and Midstream since 2003. He served as Vice President, Upstream Business Development of ConocoPhillips following completion of the merger in 2002.

James L. Gallogly was appointed Executive Vice President, Refining, Marketing and Transportation of ConocoPhillips effective April 1, 2006, having previously served as President and Chief Executive Officer of Chevron Phillips Chemical Company LLC since 2000.

Janet L. Kelly was appointed Senior Vice President, Legal, General Counsel and Corporate Secretary of ConocoPhillips effective September 1, 2007, having previously served as ConocoPhillips Deputy General Counsel since 2006. Prior to joining ConocoPhillips in 2006, she was a partner at Zelle, Hoffman, Voelbel, Mason and Gette, having previously served as Senior Vice President, Chief Administrative Officer and Chief Compliance Officer of Kmart Corporation since 2003. Prior to joining Kmart

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Corporation, she served as Executive Vice President of Corporate Development and Administration, General Counsel and Secretary of Kellogg Company since 2001.

John E. Lowe was appointed Executive Vice President, Exploration and Production of ConocoPhillips effective September 1, 2007, having previously served as ConocoPhillips Executive Vice President, Commercial since 2006. He served as ConocoPhillips Executive Vice President, Planning, Strategy and Corporate Affairs since completion of the merger in 2002.

James J. Mulva was appointed Chairman of the Board of Directors, President and Chief Executive Officer of ConocoPhillips effective October 1, 2004, having previously served as ConocoPhillips President and Chief Executive Officer since completion of the merger in 2002.

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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
2007				
First	$	**71.50**	**61.59**	**.41**
Second		**81.40**	**66.24**	**.41**
Third		**90.84**	**73.75**	**.41**
Fourth		**89.89**	**74.18**	**.41**
2006				
First	$	66.25	58.01	.36
Second		72.50	57.66	.36
Third		70.75	56.55	.36
Fourth		74.89	54.90	.36

Closing Stock Price at December 31, 2007	$	88.30
Closing Stock Price at January 31, 2008	$	80.11
Number of Stockholders of Record at January 31, 2008*		64,486

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

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Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased*	Average Price Paid per Total Shares Purchased	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, 2007	8,524,207	$85.01	8,519,500	$11,873
November 1-30, 2007	11,099,198	80.92	11,098,236	10,975
December 1-31, 2007	10,640,304	82.57	10,629,568	10,097
Total	30,263,709	$82.65	30,247,304	

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

***On January 12, 2007, we announced a stock repurchase program that provided for the repurchase of up to $1 billion of the company s common stock. On February 9, 2007, we announced plans to repurchase $4 billion of our common stock in 2007, including the $1 billion announced on*

January 12, 2007. On July 9, 2007, we announced plans to repurchase up to $15 billion of the company s common stock through the end of 2008, which included the $2 billion remaining under the previously announced $4 billion program. Acquisitions for the share repurchase programs 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 plans are held as treasury shares.

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Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2007	2006	2005	2004	2003
Sales and other operating revenues	**$ 187,437**	183,650	179,442	135,076	104,246
Income from continuing operations	**11,891**	15,550	13,640	8,107	4,593
Per common share					
Basic	**7.32**	9.80	9.79	5.87	3.37
Diluted	**7.22**	9.66	9.63	5.79	3.35
Net income	**11,891**	15,550	13,529	8,129	4,735
Per common share					
Basic	**7.32**	9.80	9.71	5.88	3.48
Diluted	**7.22**	9.66	9.55	5.80	3.45
Total assets	**177,757**	164,781	106,999	92,861	82,455
Long-term debt	**20,289**	23,091	10,758	14,370	16,340
Joint venture acquisition obligation related party	**6,294**	-	-	-	-
Mandatorily redeemable minority interests	**-**	-	-	-	141
Cash dividends declared per common share	**1.64**	1.44	1.18	.895	.815

See Management s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that will enhance an understanding of this data. The financial data for 2007 includes the impact of a $4,588 million before-tax ($4,512 million after-tax) non-cash impairment related to the expropriation of our oil interests in Venezuela. For additional information, see the Expropriated Assets section of Note 13 Impairments, in the Notes to Consolidated Financial Statements. Additionally, the acquisition of Burlington Resources in 2006 affects the comparability of the amounts included in the table above. See Note 5 Acquisition of Burlington Resources Inc., in the Notes to Consolidated Financial Statements, for additional information. See Note 2 Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for information on changes in accounting principles affecting the comparability of the amounts included in the table above.

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

February 21, 2008

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 intends, believes, expects, pla scheduled, should, anticipates, estimates, and similar expressions identify forward-looking statements. The compar 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 92.

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 32,600 employees worldwide, and at year-end 2007 had assets of $178 billion. Our stock is listed on the New York Stock Exchange under the symbol COP.

Our business is organized into six operating segments:

> Exploration and Production (E&P) This segment primarily explores for, produces, transports and markets crude oil, natural gas, 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, primarily in the United States and Trinidad. The Midstream segment primarily consists of our 50 percent equity investment in DCP Midstream, LLC.
>
> Refining and Marketing (R&M) This segment purchases, refines, markets and transports crude oil and petroleum products, mainly in the United States, Europe and Asia.
>
> LUKOIL Investment This segment consists of our equity investment in the ordinary shares of OAO LUKOIL (LUKOIL), an international, integrated oil and gas company headquartered in Russia. At December 31, 2007, our ownership interest was 20 percent based on issued shares, and 20.6 percent based on estimated shares outstanding.
>
> Chemicals This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists of our 50 percent equity investment in Chevron Phillips Chemical Company LLC (CPChem).
>
> Emerging Businesses This segment represents our investment in new technologies or businesses outside our normal scope of operations.

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Crude oil and natural gas prices, along with refining margins, are the most significant factors in our profitability. Accordingly, our overall earnings depend primarily upon the profitability of our E&P and R&M segments. Crude oil and natural gas prices, along with refining margins, are driven by market factors over which we have no control. 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. Maintaining high 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 2007, our worldwide refinery capacity utilization rate was 94 percent, compared with 92 percent in 2006. The improved utilization rate reflects less scheduled downtime and unplanned weather-related downtime. Concerning the environment, we strive to conduct our operations in a manner consistent with our environmental stewardship principles.

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

- Successful exploration and development of new fields.

- Acquisition of existing fields.

- Applying new technologies and processes to improve recovery from existing fields.

Through a combination of all three methods listed above, we have been successful in the past in maintaining or adding to our production and proved reserve base. Although it cannot be assured, we anticipate being able to do so in the future. The acquisition of Burlington Resources in March 2006 added approximately 2 billion barrels of oil equivalent to our proved reserves, and through our investments in LUKOIL during 2004, 2005 and 2006, we added about 1.9 billion barrels of oil equivalent. On January 3, 2007, we closed on a business venture with EnCana Corporation (EnCana). As part of this transaction, we added approximately 400 million barrels of oil equivalent to our proved reserves in 2007. In the three years ending December 31, 2007, our reserve replacement was 186 percent, including the impact of the Burlington Resources acquisition, our additional equity investment in LUKOIL, the EnCana business venture, and the expropriation of our Venezuelan oil assets.

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 and prudently managing our capital program, within the context of our commitment to safety and environmental stewardship, are high priorities. We monitor these costs using various methodologies that are reported to senior management monthly, on both an absolute-dollar basis and a per-unit basis. Because managing operating and overhead costs are critical to maintaining competitive positions in our industries, cost control is a component of our variable compensation programs.

With the rise in commodity prices over the last several years, and the subsequent increase in industry-wide spending on capital and major maintenance programs, we and other energy companies are experiencing inflation for the costs of certain goods and services in excess of general worldwide inflationary trends. Such costs include rates for drilling rigs, steel and other raw materials, as well as costs for skilled labor. While we work to manage the effect these inflationary pressures have on our costs, our capital program has been impacted by these factors. The continued weakening of the U.S. dollar has also contributed to higher costs. Our capital program may be further impacted by these factors going forward.

Selecting the appropriate projects in which to invest our capital dollars. We participate in capital-intensive industries. As a result, we must often invest significant capital dollars to explore for new oil and gas fields, develop newly discovered fields, maintain existing fields, or continue to maintain and improve our refinery complexes. We invest in those projects that are expected to provide an adequate financial return on invested dollars. However, there are often long lead times from the time we make an investment to the time that investment is operational and begins generating financial returns.

In January 2007, we entered into two 50/50 business ventures with EnCana to create an integrated North American heavy-oil business, consisting of a Canadian upstream general partnership, FCCL Oil Sands Partnership (FCCL), and a U.S. downstream limited liability company, WRB Refining LLC (WRB). We are obligated to contribute $7.5 billion, plus accrued interest, to FCCL over a 10-year period beginning in 2007. EnCana is obligated to contribute $7.5 billion, plus accrued interest, to WRB over a 10-year period beginning in 2007.

Our capital expenditures and investments in 2007 totaled $11.8 billion, and we anticipate capital expenditures and investments to be approximately $14.3 billion in 2008. In addition to our capital program, we increased shareholder distributions in 2007 through a combination of increased dividends and share repurchases. Our cash dividends totaled $1.64 per share in 2007, an increase of 14 percent over $1.44 per share in 2006. We repurchased $7 billion of our common stock in 2007 and have $10 billion of share repurchase authority remaining through 2008.

Managing our asset portfolio. We continue to evaluate opportunities to acquire assets that will contribute to future growth at competitive prices. We also continually assess our assets to determine if any no longer fit our strategic plans and should be sold or otherwise disposed. This management of our asset portfolio is important to ensuring our long-term growth and maintaining adequate financial returns. During 2006, we increased our investment in LUKOIL, ending the year with a 20 percent ownership interest based on issued shares. During 2006, we completed the $33.9 billion acquisition of Burlington Resources. Also during 2006, we announced the commencement of an asset rationalization program to evaluate our asset base to identify those assets that may no longer fit into our strategic plans or those that could bring more value by being monetized in the near term. This program generated proceeds of approximately $3.8 billion through December 31, 2007. In 2008, we expect to complete the disposition of our retail assets in the United States, Norway, Sweden and Denmark. We will evaluate additional opportunities to optimize and strengthen our asset portfolio as the year progresses.

Hiring, 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. In 2007, we hired approximately 2,900 new employees around the world, including university hires as well as experienced hires. 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. The ongoing hiring and training of employees is especially important given the significant number of experienced technical personnel potentially exiting the workplace over the next few years.

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

Other significant factors that can affect our profitability include:

Property and leasehold impairments. As mentioned above, we participate in capital-intensive industries. At times, these investments become impaired when our reserve estimates are revised downward, when crude oil or natural gas prices, or refinery margins decline significantly for long periods of time, or when a decision to dispose of an asset leads to a write-down to its fair market value. Property impairments in 2007, excluding the impairment of expropriated assets, totaled $442 million, compared with $383 million in 2006. We may also invest large amounts of money in exploration blocks which, if exploratory drilling proves unsuccessful, could lead to a material impairment of leasehold values.

Goodwill. As a result of mergers and acquisitions, at year-end 2007 we had $29.3 billion of goodwill on our balance sheet, compared with $31.5 billion of goodwill at year-end 2006. Although our latest tests indicate that no goodwill impairment is currently required, future deterioration in market conditions could lead to goodwill impairments that would have a substantial negative, though non-cash, effect on our profitability.

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

Fiscal and regulatory environment. As commodity prices and refining margins improved over the last several years, certain governments have responded with changes to their fiscal take. These changes have generally negatively impacted our results of operations, and further changes to government fiscal take could have a negative impact on future operations. In June 2007, our Venezuelan oil projects were expropriated, and we recorded a $4,588 million before-tax ($4,512 million after-tax) impairment (see the Expropriated Assets section of Note 13 Impairments, in the Notes to Consolidated Financial Statements). The company was also negatively impacted by increased production taxes enacted by the state of Alaska in the fourth quarter of 2007. In October 2007, the government of Ecuador increased the tax rate of the Windfall Profits Tax Law implemented in 2006, increasing the amount of government royalty entitlement on crude oil production to 99 percent of any increase in the price of crude oil above a contractual reference price. Also in October 2007, the Alberta provincial government publicly announced its intention to change the royalty structure for Crown lands, effective January 1, 2009 (see the Outlook section for additional information on the proposed royalty increase). In January 2008, we and our co-venturers agreed to the proportional dilution of our equity interests in the Republic of Kazakhstan s North Caspian Sea Production Sharing Agreement, which includes the Kashagan field, to allow the state-owned energy company to increase its ownership percentage effective January 1, 2008, subject to completion of definitive agreements on dilution and other matters. Partially offsetting the above fiscal take increases were lower corporate income tax rates enacted by Canada and Germany during 2007. These tax rate reductions applied to all corporations and were not exclusive to the oil and gas industry.

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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 were higher in 2007 compared with 2006, averaging $72.25 per barrel in 2007, an increase of 9 percent. The increase was primarily due to growth in global consumption associated with continuing economic expansions and limited spare capacity from major exporting countries. Industry natural gas prices for Henry Hub increased during 2007, primarily due to increased demand from the residential and electric power sector. These factors were moderated by higher domestic production, increased LNG imports, and high storage levels.

The Midstream segment s results are most closely linked to natural gas liquids prices. The most important factor on the profitability of this segment is the results from our 50 percent equity investment in DCP Midstream. During 2005, we increased our ownership interest in DCP Midstream from 30.3 percent to 50 percent, and we recorded a gain of $306 million, after-tax, for our equity share of DCP Midstream s sale of its general partnership interest in TEPPCO Partners, LP (TEPPCO). DCP Midstream s natural gas liquids prices increased 19 percent in 2007.

Refining margins, refinery utilization, cost control, and marketing margins primarily drive the R&M segment s results. Refining margins are subject to movements in the cost of crude oil and other feedstocks, and the sales prices for refined products, which are subject to market factors over which we have no control. Industry refining margins in the United States were stronger overall in comparison to 2006. Key factors contributing to the stronger refining margins in 2007 were lower industry refining utilization in the United States and higher distillate and gasoline demand. Wholesale marketing margins in the United States were lower in 2007, compared with those in 2006, as the market did not generally keep pace with the rising cost of crude oil.

The LUKOIL Investment segment consists of our investment in the ordinary shares of LUKOIL. In October 2004, we closed on a transaction to acquire 7.6 percent of LUKOIL s shares from the Russian government for approximately $2 billion. During the remainder of 2004, all of 2005 and 2006, we invested an additional $5.5 billion, bringing our equity ownership interest in LUKOIL to 20 percent by year-end 2006, based on issued shares. At December 31, 2007, our ownership interest was 20 percent based on issued shares and 20.6 percent based on estimated shares outstanding. We initiated this strategic investment to gain further exposure to Russia s resource potential, where LUKOIL has significant positions in proved reserves and production. We benefited from an increase in proved oil and gas reserves at an attractive cost, and our E&P segment should benefit from direct participation with LUKOIL in large oil projects in the northern Timan-Pechora province of Russia, and potential opportunities for participation in other developments.

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 other items, such as carbon-to-liquids, technology solutions, and alternative energy and programs, such as advanced hydrocarbon processes, energy conversion technologies, new petroleum-based products, and renewable fuels. Some of these technologies may 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) by business segment follows:

	Millions of Dollars		
Years Ended December 31	**2007**	2006	2005
Exploration and Production (E&P)	**$ 4,615**	9,848	8,430
Midstream	**453**	476	688
Refining and Marketing (R&M)	**5,923**	4,481	4,173
LUKOIL Investment	**1,818**	1,425	714
Chemicals	**359**	492	323
Emerging Businesses	**(8)**	15	(21)
Corporate and Other	**(1,269)**	(1,187)	(778)
Net income	**$ 11,891**	15,550	13,529

2007 vs. 2006

The lower results in 2007 were primarily the result of:

- The complete impairment ($4,512 million after-tax) of our oil interests in Venezuela resulting from their expropriation in June 2007.
- Lower crude oil production in the E&P segment.
- Decreased net income from the Chemicals segment, primarily due to lower olefins and polyolefins margins.
- Higher production and operating expenses, higher production taxes, and higher depreciation, depletion and amortization expense in the E&P segment.

These items were partially offset by:

- The net benefit of asset rationalization efforts in the E&P and R&M segments.
- Higher realized crude oil, natural gas, and natural gas liquids prices in the E&P segment.
- Higher realized worldwide refining margins, including the benefit of planned inventory reductions in the R&M segment.
- Increased equity earnings from our investment in LUKOIL due to higher estimated commodity prices and volumes, and an increase in our average equity ownership percentage.

2006 vs. 2005

The improved results in 2006, compared with 2005, were primarily the result of:

- Higher crude oil prices in the E&P segment.
- The inclusion of Burlington Resources in our results of operations for the E&P segment.
- Improved refining margins and volumes and marketing margins in the R&M segment s U.S. operations.
- Increased equity earnings from our investment in LUKOIL.

The recognition in 2006 of business interruption insurance recoveries attributable to hurricanes in 2005.

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These items were partially offset by:

- The impairment of certain assets held for sale in the R&M and E&P segments.
- Lower natural gas prices in the E&P segment.
- Higher interest and debt expense resulting from higher average debt levels due to the Burlington Resources acquisition.
- Decreased net income from the Midstream segment, reflecting the inclusion of our equity share of DCP Midstream s gain on the sale of the general partner interest in TEPPCO in our 2005 results.

Income Statement Analysis

2007 vs. 2006

Equity in earnings of affiliates increased 21 percent in 2007. The increase reflects earnings from WRB Refining LLC and FCCL Oil Sands Partnership, our downstream and upstream business ventures with EnCana, formed in January 2007. Also, we had improved results from LUKOIL, reflecting higher estimated commodity prices and volumes, and an increase in our average equity ownership percentage. These increases were partially offset by lower earnings from Hamaca and Petrozuata, our heavy-oil joint ventures in Venezuela, primarily due to the expropriation of our interests during the second quarter of 2007. Additionally, CPChem reported lower earnings, primarily due to lower olefins and polyolefins margins.

Other income increased 188 percent during 2007, primarily due to:

- Higher net gains on asset dispositions associated with asset rationalization efforts.
- The release of escrowed funds related to the extinguishment of Hamaca project financing.
- The settlement of retroactive adjustments for crude oil quality differentials on Trans-Alaska Pipeline System shipments (Quality Bank) in 2007.

These increases were partially offset by the recognition in 2006 of recoveries on business interruption insurance claims attributable to losses sustained from hurricanes in 2005.

Exploration expenses increased 21 percent during 2007, primarily reflecting the amortization of unproved North American leaseholds obtained in the Burlington Resources acquisition and the impairment of an international exploration license. The increase also reflects higher geological and geophysical expenses and higher dry hole costs.

Depreciation, depletion and amortization (DD&A) increased 14 percent during 2007, primarily resulting from the addition of Burlington Resources assets in the E&P segment s depreciable asset base for a full year in 2007 versus only nine months in 2006.

Impairment expropriated assets reflects a non-cash impairment of $4,588 million before-tax related to the expropriation of our oil interests in Venezuela recorded in the second quarter of 2007. For additional information, see the Expropriated Assets section of Note 13 Impairments, in the Notes to Consolidated Financial Statements.

Impairments, which excludes the expropriation of our oil interests in Venezuela, decreased 35 percent during 2007, primarily due to the significant impairments recorded in 2006 of certain assets held for sale in the R&M segment, comprised of properties, plants and equipment, trademark intangibles and goodwill. See Note 13 Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Interest and debt expense increased 15 percent during 2007, primarily due to the interest expense component of the Quality Bank settlements, as well as higher expense associated with the funding requirements for the business venture with EnCana.

Foreign currency transaction gains during 2007 primarily reflect the strengthening of the Canadian dollar against the U.S. dollar.

Our effective tax rate in 2007 was 49 percent, compared with 45 percent in 2006. The change in the effective rate for 2007 was primarily due to the impact of the expropriation of our oil interests in Venezuela in the second quarter of 2007. This impact was partially offset by the effect of income tax law changes enacted during 2007, and by a higher proportion of income in higher tax rate jurisdictions during 2006.

2006 vs. 2005

Sales and other operating revenues increased 2 percent in 2006, compared with 2005, while purchased crude oil, natural gas and products decreased 5 percent. The increase in sales and other operating revenues was primarily due to higher realized prices for crude oil and petroleum products, as well as higher sales volumes associated with the Burlington Resources acquisition. These increases were mostly offset by decreases associated with the implementation of Emerging Issues Task Force Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. The decrease in purchased crude oil, natural gas and products was primarily the result of the implementation of Issue No. 04-13. See Note 2 Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for additional information on the impact of this Issue on our income statement.

Equity in earnings of affiliates increased 21 percent in 2006, compared with 2005. The increase reflects improved results from:

- LUKOIL, resulting from an increase in our ownership percentage, as well as higher estimated crude oil and petroleum products prices and volumes, and a net benefit from the alignment of our estimate of LUKOIL s fourth quarter 2005 net income to LUKOIL s reported results.

- CPChem, due to higher margins and volumes, as well as the recognition of a business interruption insurance net benefit.

These increases were offset partially by the inclusion of our equity share of DCP Midstream s gain on the sale of the general partner interest in TEPPCO in our 2005 results.

Other income increased 47 percent during 2006, compared with 2005, primarily due to the recognition in 2006 of recoveries on business interruption insurance claims. In addition, interest income was higher in 2006, compared with 2005. These increases were partially offset by higher net gains on asset dispositions recorded in 2005.

Production and operating expenses increased 22 percent in 2006, compared with 2005. The increase was primarily due to the acquired Burlington Resources assets, increased production at the Bayu-Undan field associated with the Darwin liquefied natural gas (LNG) project in Australia, the first year of production in Libya, and the acquisition of the Wilhelmshaven refinery in Germany.

Exploration expenses increased 26 percent in 2006, compared with 2005, primarily due to the Burlington Resources acquisition.

DD&A increased 71 percent during 2006, compared with 2005. The increase was primarily the result of the addition of Burlington Resources assets in E&P s depreciable asset base. In addition, the acquisition of the Wilhelmshaven refinery increased DD&A recorded by the R&M segment.

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Impairments were $683 million in 2006, compared with $42 million in 2005. The increase primarily relates to the impairment in 2006 of certain assets held for sale in the R&M and E&P segments. We also recorded an impairment charge in the E&P segment associated with assets in the Canadian Rockies Foothills area.

Interest and debt expense increased from $497 million in 2005 to $1,087 million in 2006, primarily due to higher average debt levels as a result of the financing required to partially fund the acquisition of Burlington Resources.

Restructuring Program

As a result of the acquisition of Burlington Resources, we implemented a restructuring program in March 2006 to capture the synergies of combining the two companies. Under this program, we recorded accruals totaling $230 million in 2006 for employee severance payments, site closings, incremental pension benefit costs associated with the workforce reductions, and employee relocations. Approximately 600 positions were identified for elimination, most of which were in the United States.

Of the total accrual, $224 million was reflected in the Burlington Resources purchase price allocation as an assumed liability, and $6 million ($4 million after-tax) related to ConocoPhillips was reflected in selling, general and administrative expenses in 2006. Included in the total accruals of $230 million was $12 million related to pension benefits to be paid in conjunction with other retirement benefits over a number of future years. See Note 6 Restructuring, in the Notes to Consolidated Financial Statements, for additional information.

Segment Results
E&P

	2007	2006	2005
	Millions of Dollars		
Net Income			
Alaska	$ **2,255**	2,347	2,552
Lower 48	**1,993**	2,001	1,736
United States	**4,248**	4,348	4,288
International	**367**	5,500	4,142
	$ **4,615**	9,848	8,430
	Dollars Per Unit		
Average Sales Prices			
Crude oil (per barrel)			
United States	$ **68.00**	61.09	51.09
International	**70.79**	63.38	52.27
Total consolidated	**69.47**	62.39	51.74
Equity affiliates*	**45.31**	46.01	37.79
Worldwide E&P	**67.11**	60.37	49.87
Natural gas (per thousand cubic feet)			
United States	**5.98**	6.11	7.12
International	**6.51**	6.27	5.78
Total consolidated	**6.26**	6.20	6.32
Equity affiliates*	**.30**	.30	.26
Worldwide E&P	**6.26**	6.19	6.30
Natural gas liquids (per barrel)			
United States	**46.00**	40.35	40.40
International	**48.80**	42.89	36.25
Total consolidated	**47.13**	41.50	38.32
Equity affiliates*	**-**	-	-
Worldwide E&P	**47.13**	41.50	38.32
Average Production Costs Per Barrel of Oil Equivalent			
United States	$ **6.52**	5.43	4.24
International	**7.68**	5.65	4.58
Total consolidated	**7.13**	5.55	4.43
Equity affiliates*	**8.92**	5.83	4.93
Worldwide E&P	**7.21**	5.57	4.47

**Excludes our equity share of LUKOIL, which is reported in the LUKOIL Investment segment.*

	Millions of Dollars		
Worldwide Exploration Expenses			

General administrative, geological and geophysical, and lease rentals	**$ 544**	483	312
Leasehold impairment	**254**	157	116
Dry holes	**209**	194	233
	$ 1,007	834	661

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	2007	2006	2005
	Thousands of Barrels Daily		
Operating Statistics			
Crude oil produced			
Alaska	**261**	263	294
Lower 48	**102**	104	59
United States	**363**	367	353
Europe	**210**	245	257
Asia Pacific	**87**	106	100
Canada	**19**	25	23
Middle East and Africa	**81**	106	53
Other areas	**10**	7	-
Total consolidated	**770**	856	786
Equity affiliates*			
Canada	**27**	-	-
Russia and Caspian	**15**	15	15
Venezuela	**42**	101	106
	854	972	907
Natural gas liquids produced			
Alaska	**19**	17	20
Lower 48	**79**	62	30
United States	**98**	79	50
Europe	**14**	13	13
Asia Pacific	**14**	18	16
Canada	**27**	25	10
Middle East and Africa	**2**	1	2
	155	136	91
	Millions of Cubic Feet Daily		
Natural gas produced**			
Alaska	**110**	145	169
Lower 48	**2,182**	2,028	1,212
United States	**2,292**	2,173	1,381
Europe	**961**	1,065	1,023
Asia Pacific	**579**	582	350
Canada	**1,106**	983	425
Middle East and Africa	**125**	142	84
Other areas	**19**	16	-

Total consolidated	**5,082**	4,961	3,263
Equity affiliates*			
Venezuela	**5**	9	7
	5,087	4,970	3,270

	Thousands of Barrels Daily		
Mining operations			
Syncrude produced	**23**	21	19

**Excludes our equity share of LUKOIL, which is reported in the LUKOIL Investment segment.*
***Represents quantities available for sale. Excludes gas equivalent of natural gas liquids shown above.*

The E&P segment explores for, produces, transports and markets crude oil, natural gas, and natural gas liquids on a worldwide basis. It also mines deposits of oil sands in Canada to extract the bitumen and upgrade it into a synthetic crude oil. At December 31, 2007, our E&P operations were producing in the United States, Norway, the United Kingdom, the Netherlands, Canada, Nigeria, Ecuador, Argentina, offshore Timor-Leste in the Timor Sea, Australia, China, Indonesia, Algeria, Libya, Vietnam, and Russia.

2007 vs. 2006

Net income from the E&P segment decreased 53 percent in 2007. In the second quarter of 2007, we recorded a non-cash impairment of $4,588 million before-tax ($4,512 million after-tax) related to the expropriation of our oil interests in Venezuela. For additional information, see the Expropriated Assets section of Note 13 Impairments, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference. The decrease in net income during 2007 reflects this impairment, as well as lower crude oil production, higher production taxes and operating costs, and higher DD&A expense. These decreases were partially offset by:

- Higher realized crude oil, natural gas liquids and natural gas prices.
- A net benefit from asset rationalization efforts.
- A benefit related to the release of escrowed funds in connection with the extinguishment of the Hamaca project financing.
- The Quality Bank settlements.

If crude oil prices in 2008 do not remain at the levels experienced in 2007, and if costs continue to increase, the E&P segment s earnings would be negatively impacted. See the Business Environment and Executive Overview section for additional information on industry crude oil and natural gas prices and inflationary cost pressures.

Proved reserves at year-end 2007 were 8.72 billion barrels of oil equivalent (BOE), compared with 9.36 billion BOE at year-end 2006. This excludes the estimated 1,838 million BOE and 1,805 million BOE included in the LUKOIL Investment segment at year-end 2007 and 2006, respectively. Also excluded is our share of Canadian Syncrude mining operations, which was 221 million barrels at year-end 2007, compared with 243 million barrels at year-end 2006.

U.S. E&P

Net income from our U.S. E&P operations decreased 2 percent, primarily due to higher production taxes in Alaska, higher operating costs and DD&A expense, and lower crude oil production. These decreases were mostly offset by:

- Higher crude oil and natural gas liquids prices, and higher natural gas and natural gas liquids production.
- The Quality Bank settlements.
- Gains on the sale of assets in Alaska and the Gulf of Mexico.

In December 2007, the state of Alaska enacted new production tax legislation, with retroactive provisions, which results in a higher production tax structure for ConocoPhillips.

U.S. E&P production averaged 843,000 BOE per day in 2007, an increase of 4 percent from 808,000 BOE per day in 2006. Production was impacted by the inclusion of the Burlington Resources assets for the full year of 2007, offset slightly by normal field decline.

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International E&P

Net income from our international E&P operations decreased 93 percent, primarily due to the impairment of expropriated assets in Venezuela, lower crude oil production, higher DD&A expense, and higher operating costs. These decreases were partially offset by higher crude oil and natural gas prices, a net benefit from asset rationalization efforts, and the benefit from the release of the escrowed funds related to the Hamaca project.

International E&P production averaged 1,014,000 BOE per day in 2007, a decrease of 10 percent from 1,128,000 BOE per day in 2006. Production was impacted by the expropriation of our Venezuelan oil projects, planned and unplanned downtime in Australia and the North Sea, production sharing contract impacts in Australia, our exit from Dubai, and the effect of asset dispositions. These decreases were slightly offset by new production volumes from our upstream business venture with EnCana, as well as inclusion of the Burlington Resources assets for the full year of 2007. Our Syncrude mining operations produced 23,000 barrels per day in 2007, compared with 21,000 barrels per day in 2006.

2006 vs. 2005

Net income from the E&P segment increased 17 percent in 2006, compared with 2005. The increase was primarily due to higher realized crude oil prices and, to a lesser extent, higher sales prices for natural gas liquids and Syncrude. In addition, increased sales volumes, primarily the result of the Burlington Resources acquisition, contributed positively to net income in 2006. These items were partially offset by lower realized natural gas prices, higher exploration expenses, the negative impacts of changes in tax laws, and asset impairments.

U.S. E&P

Net income from our U.S. E&P operations increased slightly in 2006, compared with 2005, primarily resulting from higher crude oil prices, as well as increased crude oil, natural gas, and natural gas liquids production in the Lower 48 states, reflecting the Burlington Resources acquisition. These increases were partially offset by lower natural gas prices, higher exploration expenses, lower production levels in Alaska, and higher production taxes in Alaska.

In August 2006, the state of Alaska enacted new production tax legislation, retroactive to April 1, 2006. The new legislation resulted in a higher production tax structure for ConocoPhillips.

U.S. E&P production on a BOE basis averaged 808,000 barrels per day in 2006, compared with 633,000 barrels per day in 2005. Production was favorably impacted in 2006 by the addition of volumes from the Burlington Resources assets, offset slightly by decreases in production levels in Alaska. Production in Alaska was negatively impacted by operational shut downs and weather-related transportation delays.

International E&P

Net income from our international E&P operations increased 33 percent in 2006, compared with 2005, reflecting higher crude oil, natural gas, and natural gas liquids prices and production, as well as higher levels of LNG production from the Darwin LNG facility associated with the Bayu-Undan field in the Timor Sea. These increases were offset partially by increased exploration expenses and a $93 million after-tax impairment charge associated with assets in the Canadian Rockies Foothills area. In addition, the increases to net income were partially offset by the net negative impacts of tax law changes in the United Kingdom, Canada, China, Venezuela, and Algeria.

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During 2006, significant tax legislation was enacted in the United Kingdom and in Canada. The United Kingdom increased income tax rates on upstream income, resulting in a negative earnings impact of $470 million to adjust 2006 taxes and restate deferred tax liabilities. In Canada, an overall rate reduction in 2006 resulted in a favorable earnings impact of $401 million to restate deferred tax liabilities.

International E&P production averaged 1,128,000 BOE per day in 2006, an increase of 24 percent from 910,000 BOE per day in 2005. Production was favorably impacted in 2006 by the addition of Burlington Resources assets, higher gas production at Bayu-Undan associated with the Darwin LNG ramp-up in Australia, and the 2006 re-entry into Libya. Our Syncrude mining operations produced 21,000 barrels per day in 2006, compared with 19,000 barrels per day in 2005.

Midstream

		2007	2006	2005
		Millions of Dollars		
Net Income*	**$**	**453**	476	688
**Includes DCP Midstream-related net income:*	*$*	***336***	*385*	*591*
		Dollars Per Barrel		
Average Sales Prices				
U.S. natural gas liquids*				
Consolidated	**$**	**47.93**	40.22	36.68
Equity		**46.80**	39.45	35.52

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

	2007	2006	2005
	Thousands of Barrels Daily		
Operating Statistics			
Natural gas liquids extracted*	**211**	209	195
Natural gas liquids fractionated**	**173**	144	168

**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, LLC, as well as our other natural gas gathering and processing operations, and natural gas liquids fractionation and marketing businesses, primarily in the United States and Trinidad.

2007 vs. 2006

Net income from the Midstream segment decreased 5 percent in 2007, reflecting a shift in natural gas purchase contract terms that are more favorable to natural gas producers. In addition, earnings from DCP Midstream were lower, primarily due to increased operating costs, mainly repairs, maintenance and asset integrity work. The results also reflect a positive tax adjustment included in the 2006 results. These decreases were partially offset by higher natural gas liquids prices.

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2006 vs. 2005

Net income from the Midstream segment decreased 31 percent in 2006, compared with 2005, primarily due to the gain from the sale of DCP Midstream s interest in TEPPCO included in 2005 results. Our net share of this gain was $306 million on an after-tax basis. This decrease was partially offset by a $24 million positive tax adjustment recorded in 2006 to the gain recorded in 2005 on the sale of DCP Midstream s interest in TEPPCO, as well as higher natural gas liquids prices and an increased ownership interest in DCP Midstream.

In July 2005, ConocoPhillips increased its ownership interest in DCP Midstream to 50 percent from 30.3 percent.

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R&M

	2007	2006	2005
	Millions of Dollars		
Net Income			
United States	**$ 4,615**	3,915	3,329
International	**1,308**	566	844
	$ 5,923	4,481	4,173

	Dollars Per Gallon		
U.S. Average Sales Prices*			
Gasoline			
Wholesale	**$ 2.27**	2.04	1.73
Retail	**2.42**	2.18	1.88
Distillates wholesale	**2.29**	2.11	1.80

**Excludes excise taxes.*

	Thousands of Barrels Daily		
Operating Statistics			
Refining operations*			
United States			
Crude oil capacity**	**2,035**	2,208	2,180
Crude oil runs	**1,944**	2,025	1,996
Capacity utilization (percent)	**96%**	92	92
Refinery production	**2,146**	2,213	2,186
International			
Crude oil capacity**	**687**	651	428
Crude oil runs	**616**	591	424
Capacity utilization (percent)	**90%**	91	99
Refinery production	**633**	618	439
Worldwide			
Crude oil capacity**	**2,722**	2,859	2,608
Crude oil runs	**2,560**	2,616	2,420
Capacity utilization (percent)	**94%**	92	93
Refinery production	**2,779**	2,831	2,625
Petroleum products sales volumes			
United States			
Gasoline	**1,244**	1,336	1,374
Distillates	**872**	850	876
Other products	**432**	531	519

	2,548	2,717	2,769
International	**697**	759	482
	3,245	3,476	3,251

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

***Weighted-average crude oil capacity for the periods. Actual capacity at year-end 2007, 2006 and 2005, was 2,037,000, 2,208,000, and 2,182,000 barrels per day, respectively, for our domestic refineries, and 669,000, 693,000, and 482,000 barrels per day, respectively, for our international refineries.*

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

2007 vs. 2006

Net income from the R&M segment increased 32 percent in 2007. The increase resulted primarily from:

- The net benefit of asset rationalization efforts.
- Higher realized worldwide refining margins, reflecting in part the impact of planned inventory reductions, including a benefit of $260 million from the liquidation of prior year layers under the last-in, first-out (LIFO) method.
- Higher U.S. Gulf and East Coast refining volumes due to lower planned maintenance and less weather-related downtime.
- A $141 million deferred tax benefit related to tax legislation in Germany during the third quarter of 2007.

These increases were partially offset by the net impact of our contribution of assets to WRB Refining LLC (WRB), our downstream business venture with EnCana; foreign currency impacts; and lower marketing sales volumes due to asset sales. See the Business Environment and Executive Overview section for our view of the factors supporting industry refining and marketing margins.

We expect our average worldwide refinery crude oil utilization rate for 2008 to average in the mid-nineties.

U.S. R&M

Net income from our U.S. R&M operations increased 18 percent in 2007, primarily due to:

- Higher refining volumes at our Gulf and East Coast refineries.
- Higher realized refining and marketing margins, due in part to the benefit of planned inventory reductions.

These items were partially offset by the net impact of our contribution of the Wood River and Borger refineries to WRB, and the impact of business interruption insurance recoveries on our 2006 results.

Our U.S. refining capacity utilization rate was 96 percent in 2007, compared with 92 percent in 2006, primarily reflecting lower planned maintenance and less weather-related downtime.

International R&M

Net income from our international R&M operations increased 131 percent in 2007, due primarily to:

- The net benefit of asset rationalization efforts.
- The deferred tax benefit related to the tax legislation in Germany.
- Higher realized refining margins.

These increases were partially offset by foreign currency impacts and lower marketing volumes due to the asset sales.

Our international refining capacity utilization rate was 90 percent in 2007, compared with 91 percent in 2006. The 2007 utilization rate was affected by a temporary idling of the Wilhelmshaven refinery in Germany during the month of August due to economic conditions.

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2006 vs. 2005

Net income from the R&M segment increased 7 percent in 2006, compared with 2005. The increase resulted primarily from:

- Higher U.S. refining and marketing margins and higher U.S. refining volumes.
- The recognition of a net benefit related to business interruption insurance.
- The inclusion of an $83 million charge for the cumulative effect of adopting Financial Accounting Standards Board (FASB) Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143 (FIN 47) in the results for 2005.

The increase in net income was partially offset by impairments on assets held for sale recognized in 2006, as well as higher depreciation expense.

U.S. R&M

Net income from our U.S. R&M operations increased 18 percent in 2006, compared with 2005, primarily due to:

- Higher refining and marketing margins, and higher refining volumes.
- The recognition of a net $111 million business interruption insurance benefit.
- A $78 million charge for the cumulative effect of adopting FIN 47 in 2005.

These items were partially offset by after-tax impairments of $227 million associated with certain assets held for sale, as well as higher depreciation expense.

Our U.S. refining capacity utilization rate was 92 percent in 2006, the same as in 2005, reflecting unplanned weather-related downtime in both years.

International R&M

Net income from our international R&M operations decreased 33 percent in 2006, compared with 2005, due primarily to:

- The recognition of a $214 million after-tax impairment charge on certain assets held for sale.
- Lower refining margins.
- Preliminary engineering costs for certain refinery-related projects.

These decreases were partially offset by favorable foreign currency exchange impacts and higher refining and marketing sales volumes.

Our international refining capacity utilization rate was 91 percent in 2006, compared with 99 percent in 2005. The decrease reflected scheduled downtime at certain refineries and unscheduled downtime at the Humber refinery in the United Kingdom.

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LUKOIL Investment

	Millions of Dollars		
	2007	2006	2005
Net Income	**$ 1,818**	1,425	714
Operating Statistics*			
Net crude oil production (thousands of barrels daily)	**401**	360	235
Net natural gas production (millions of cubic feet daily)	**256**	244	67
Net refinery crude oil processed (thousands of barrels daily)	**214**	179	122

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

This segment represents our investment in the ordinary shares of LUKOIL, an international, integrated oil and gas company headquartered in Russia, which we account for under the equity method. During 2005, we expended $2,160 million to purchase LUKOIL s ordinary shares, increasing our ownership interest to 16.1 percent. We expended another $2,715 million to increase our ownership interest in LUKOIL to 20 percent at December 31, 2006, based on 851 million issued shares. At December 31, 2007, our ownership interest was 20 percent based on issued shares. Our ownership interest based on estimated shares outstanding, used for equity-method accounting, was 20.6 percent at December 31, 2006 and 2007.

2007 vs. 2006

Net income from the LUKOIL Investment segment increased 28 percent during 2007, primarily due to higher estimated realized prices, higher estimated volumes, and an increase in our average equity ownership. The increase was partially offset by higher estimated taxes and operating costs, as well as the net impact from the alignment of estimated net income to reported results.

Because LUKOIL s accounting cycle close and preparation of U.S. generally accepted accounting principles (GAAP) financial statements occur subsequent to our reporting deadline, our equity earnings and statistics for our LUKOIL investment are estimated, based on current market indicators, publicly available LUKOIL operating results, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. This estimate-to-actual adjustment will be a recurring component of future period results. The adjustment to estimated results for the fourth quarter of 2006, recorded in 2007, decreased net income $19 million, compared with a $71 million increase to net income recorded in 2006 to adjust the estimated results for the fourth quarter of 2005.

In addition to our estimate of our equity share of LUKOIL s earnings, this segment reflects the amortization of the basis difference between our equity interest in the net assets of LUKOIL and the historical cost of our investment in LUKOIL, and also includes the costs associated with our employees seconded to LUKOIL.

2006 vs. 2005

Net income from the LUKOIL Investment segment increased 100 percent during 2006, compared with 2005, primarily as a result of our increased equity ownership, higher estimated prices and volumes, and a net benefit from the alignment of our estimate of LUKOIL s fourth quarter 2005 net income to LUKOIL s reported results.

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Chemicals

	Millions of Dollars		
	2007	2006	2005
Net Income	$ **359**	492	323

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

2007 vs. 2006

Net income from the Chemicals segment decreased 27 percent during 2007, primarily due to lower olefins and polyolefins margins and higher turnaround and weather-related repair costs, offset partially by a capital-loss tax benefit of $65 million recorded in the fourth quarter of 2007.

2006 vs. 2005

Net income from the Chemicals segment increased 52 percent during 2006, compared with 2005. Results for 2006 reflected improved olefins and polyolefins margins and volumes. The results for 2006 also included a hurricane-related business interruption insurance benefit of $20 million after-tax, as well as lower utility costs due to decreased natural gas prices.

Emerging Businesses

	Millions of Dollars		
	2007	2006	2005
Net Income (Loss)			
Power	$ **53**	82	43
Other	**(61)**	(67)	(64)
	$ **(8)**	15	(21)

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 other items, such as carbon-to-liquids, technology solutions, and alternative energy and programs, such as advanced hydrocarbon processes, energy conversion technologies, new petroleum-based products, and renewable fuels.

2007 vs. 2006

The Emerging Businesses segment had a net loss of $8 million in 2007, compared with net income of $15 million in 2006. The decrease reflects lower margins from the Immingham power plant in the United Kingdom, as well as higher spending associated with alternative energy programs. These decreases were slightly offset by the inclusion of a write-down of a damaged gas turbine at a domestic power plant in 2006 results.

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2006 vs. 2005

The Emerging Businesses segment had net income of $15 million in 2006, compared with a net loss of $21 million in 2005. The improved results reflect higher international power margins and volumes. The increase in net income was partially offset by the write-down of a damaged gas turbine, as well as lower domestic power margins and volumes.

Corporate and Other

	Millions of Dollars		
	2007	2006	2005
Net Loss			
Net interest	**$ (820)**	(870)	(467)
Corporate general and administrative expenses	**(176)**	(133)	(183)
Discontinued operations	**-**	-	(23)
Acquisition-related costs	**(44)**	(98)	-
Other	**(229)**	(86)	(105)
	$ (1,269)	(1,187)	(778)

2007 vs. 2006

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 decreased 6 percent in 2007, primarily due to higher amounts of interest being capitalized and higher interest income. These decreases were partially offset by the net impact of the interest components of the Quality Bank settlements and a premium on the early retirement of debt.

Corporate general and administrative expenses increased 32 percent in 2007, primarily due to higher benefit-related expenses.

Acquisition-related costs in 2007 included transition costs associated with the Burlington Resources acquisition.

The category Other includes certain foreign currency transaction gains and losses, and environmental costs associated with sites no longer in operation. Results from Other were primarily impacted by foreign currency losses in 2007.

2006 vs. 2005

Net interest increased 86 percent in 2006, compared with 2005. The increase was primarily due to higher average debt levels as a result of the financing required to partially fund the acquisition of Burlington Resources. The increases were partially offset by higher amounts of interest being capitalized, as well as higher premiums incurred in 2005 on the early retirement of debt.

Corporate general and administrative expenses decreased 27 percent in 2006, compared with 2005, primarily due to reduced benefit-related expenses.

Acquisition-related costs in 2006 included seismic relicensing and other transition costs associated with the Burlington Resources acquisition.

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Results from Other improved during 2006, compared with 2005, primarily due to foreign currency transaction gains in 2006, versus losses in 2005, partially offset by certain tax items not directly attributable to the operating segments.

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CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars Except as Indicated		
	2007	2006	2005
Net cash provided by operating activities	**$ 24,550**	21,516	17,628
Notes payable and long-term debt due within one year	**1,398**	4,043	1,758
Total debt	**21,687**	27,134	12,516
Minority interests	**1,173**	1,202	1,209
Common stockholders equity	**88,983**	82,646	52,731
Percent of total debt to capital*	**19%**	24	19
Percent of floating-rate debt to total debt	**25**	41	9

**Capital includes total debt, minority interests and common stockholders equity.*

To meet our short- and long-term liquidity requirements, we look to a variety of funding sources. Cash generated from operating activities is the primary source of funding. In addition, during 2007 we raised $3,572 million in proceeds from asset dispositions. During 2007, available cash was used to support our ongoing capital expenditures and investments program, repurchase shares of our common stock, repay debt, provide loan financing to certain related parties, pay dividends, and meet the funding requirements related to the business venture with EnCana. During 2007, cash and cash equivalents increased $639 million to $1,456 million.

In addition to cash flows from operating activities and proceeds from asset sales, we also rely on our cash balance, commercial paper and credit facility programs, and our shelf registration statements, to support our short- and long-term liquidity requirements. We anticipate these sources of liquidity will be adequate to meet our funding requirements in the near- and long-term, including our capital spending program, our share repurchase program, dividend payments, required debt payments, and the funding requirements related to the business venture with EnCana. For additional information about the EnCana transaction, see Note 16 Joint Venture Acquisition Obligation, in the Notes to Consolidated Financial Statements.

Our cash flows from operating activities increased in each of the annual periods from 2005 through 2007. Favorable market conditions played a significant role in the upward trend of our cash flows from operating activities. In addition, cash flows in 2007 benefited from the full year inclusion of the operating activity of Burlington Resources, versus only nine months in 2006. Absent any unusual event during 2008, we expect market conditions will again be the most important factor affecting our 2008 operating cash flows.

Significant Sources of Capital

Operating Activities

During 2007, cash of $24,550 million was provided by operating activities, a 14 percent increase over cash from operations of $21,516 million in 2006. Contributing to the increase was a planned inventory reduction in the 2007 period, partially related to the formation of the WRB downstream business venture; the impact of the Burlington Resources acquisition late in the first quarter of 2006; and higher worldwide crude oil prices in 2007. These positive factors were partially offset by the absence of dividends from our Venezuelan operations in 2007.

During 2006, cash flow from operations increased $3,888 million to $21,516 million. The improvement, compared with 2005, reflects higher worldwide crude oil prices and U.S. refining margins, higher distributions from equity affiliates, and the impact of the Burlington Resources acquisition, partially offset by higher interest payments.

While the stability of our cash flows from operating activities benefits from geographic diversity and the effects of upstream and downstream integration, our short- and long-term operating cash flows are highly dependent upon prices for crude oil, natural gas and natural gas liquids, as well as refining and marketing margins. During 2007 and 2006, we benefited from favorable crude oil and natural gas prices, as well as refining margins. The sustainability of these prices and margins is driven by market conditions over which we have no control. Absent other mitigating factors, as these prices and margins fluctuate, we would expect a corresponding change in our operating cash flows.

The level of our production volumes of crude oil, natural gas and natural gas liquids also impacts our cash flows. These production levels are impacted by such factors as acquisitions and dispositions of fields, field production decline rates, new technologies, operating efficiency, weather conditions, the addition of proved reserves through exploratory success, and the timely and cost-effective development of those proved reserves. 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 experienced with commodity prices.

After adjusting our production rates for the impact of the expropriation of our Venezuelan oil operations in June 2007, our BOE production has increased in each of the past three years. These increases were driven primarily by acquisitions, including our increased ownership interest in LUKOIL during 2005 and 2006, the acquisition of Burlington Resources in 2006 and the business venture with EnCana in 2007. Our adjusted 2007 production was approximately 2.25 million BOE per day, after reductions for the expropriation, our exit from Dubai and the sale of non-core assets. We expect 2008 annual production to be similar to the adjusted 2007 amount. Through 2012, we expect our annual production growth rate to average approximately 2 percent. These projections are tied to projects currently scheduled to begin production or ramp-up in those years and exclude our Canadian Syncrude mining operations.

To maintain or grow our production volumes, we must continue to add to our proved reserve base. Our reserve replacement over the three-year period ending December 31, 2007, was 186 percent. The purchase of reserves in place was a significant factor in replacing our reserves over the past three years, partially offset by the expropriation of our Venezuelan oil assets. Significant purchases during this three-year period included reserves added in 2007 related to the EnCana business venture, the 2006 acquisition of Burlington Resources and the 2005 re-entry into Libya, as well as proved reserves added through our investments in LUKOIL.

We are developing and pursuing projects we anticipate will allow us to add to our reserve base going forward. 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 Critical Accounting Estimates, engineering estimates of proved reserves are imprecise, and therefore, each year reserves may be revised upward or downward due to the impact of changes in oil and gas prices or as more technical data becomes available on the reservoirs. In 2007 and 2005, revisions increased our reserves, while in 2006, revisions decreased reserves. It is not possible to reliably predict how revisions will impact reserve quantities in the future. See the Capital Spending section for an analysis of proved undeveloped reserves.

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In addition, the level and quality of output from our refineries impacts our cash flows. The output at our refineries is impacted by such factors as operating efficiency, maintenance turnarounds, 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 experienced with refining margins.

In 2006, we received approximately $1.1 billion in distributions from two heavy-oil projects in Venezuela. The majority of these distributions represented operating results from previous years. We did not receive an operating distribution related to these projects in 2007. See the Outlook section for additional discussion concerning our operations in Venezuela.

Asset Sales

Proceeds from asset sales in 2007 were $3,572 million, compared with $545 million in 2006. The increase is mainly due to ongoing asset rationalization efforts related to the program we announced in April 2006 to dispose of assets that no longer fit into our strategic plans or those that could bring more value by being monetized in the near term. Through December 31, 2007, this program had generated proceeds of approximately $3.8 billion since inception. In 2008, we expect to complete the disposition of our retail assets in the United States, Norway, Sweden and Denmark.

Commercial Paper and Credit Facilities

In September 2007, we replaced our $5 billion and $2.5 billion revolving credit facilities, with one $7.5 billion revolving credit facility, expiring in September 2012. This facility may be used as direct bank borrowings, as support for the ConocoPhillips $7.5 billion commercial paper program, as support for the ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program, or as support for issuances of letters of credit totaling up to $750 million. The facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or ratings. The credit agreement contains 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.

Our primary funding source for short-term working capital needs is the ConocoPhillips $7.5 billion commercial paper program, a portion of which may be denominated in other currencies (limited to euro 3 billion equivalent). Commercial paper maturities are generally limited to 90 days. The ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program is used to fund commitments relating to the Qatargas 3 project. At December 31, 2007 and 2006, we had no outstanding borrowings under the credit facilities, but $41 million in letters of credit had been issued at both dates. Under both commercial paper programs, there was $725 million of commercial paper outstanding at December 31, 2007, compared with $2,931 million at December 31, 2006. Since we had $725 million of commercial paper outstanding and had issued $41 million of letters of credit, we had access to $6.7 billion in borrowing capacity under our revolving credit facility at December 31, 2007.

At December 31, 2007, Moody s Investor Service had a rating of A1 on our senior long-term debt; and Standard and Poors Rating Service and Fitch had ratings of A. We do not have any ratings triggers on any of our corporate debt that would cause an automatic event of default in the event of a downgrade of our credit rating and thereby impact our access to liquidity. In the event that our credit rating deteriorated to a level that would prohibit us from accessing the commercial paper market, we would still be able to access funds under our $7.5 billion revolving credit facilities.

Shelf Registrations

We have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission (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.

We also have on file with the SEC a shelf registration statement under which ConocoPhillips Canada Funding Company I and ConocoPhillips Canada Funding Company II, both wholly owned subsidiaries, could issue an indeterminate amount of senior debt securities, fully and unconditionally guaranteed by ConocoPhillips and ConocoPhillips Company.

Minority Interests

At December 31, 2007, we had outstanding $1,173 million of equity in less than wholly owned consolidated subsidiaries held by minority interest owners, including a minority interest of $508 million in Ashford Energy Capital S.A. The remaining minority interest amounts are primarily related to operating joint ventures we control. The largest of these, $648 million, was related to the Darwin LNG project located in northern Australia.

In December 2001, in order to raise funds for general corporate purposes, ConocoPhillips and Cold Spring Finance S.a.r.l. (Cold Spring) formed Ashford Energy Capital S.A. through the contribution of a $1 billion ConocoPhillips subsidiary promissory note and $500 million cash by Cold Spring. Through its initial $500 million investment, Cold Spring is entitled to a cumulative annual preferred return based on three-month LIBOR rates, plus 1.32 percent. The preferred return at December 31, 2007, was 6.55 percent. In 2008, and at each 10-year anniversary thereafter, Cold Spring may elect to remarket their investment in Ashford, and if unsuccessful, could require ConocoPhillips to provide a letter of credit in support of Cold Spring s investment, or in the event that such letter of credit is not provided, then cause the redemption of their investment in Ashford. Should ConocoPhillips credit rating fall below investment grade on a redemption date, Ashford would require a letter of credit to support $475 million of the term loans, as of December 31, 2007, made by Ashford to other ConocoPhillips subsidiaries. If the letter of credit is not obtained within 60 days, Cold Spring could cause Ashford to sell the ConocoPhillips subsidiary notes. At December 31, 2007, Ashford held $2.0 billion of ConocoPhillips subsidiary notes and $29 million in investments unrelated to ConocoPhillips. We report Cold Spring s investment as a minority interest because it is not mandatorily redeemable and the entity does not have a specified liquidation date. Other than the obligation to make payment on the subsidiary notes described above, Cold Spring does not have recourse to our general credit.

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, 2007, we were liable for certain contingent obligations under the following contractual arrangements:

Qatargas 3: Qatargas 3 is an integrated project to produce and liquefy natural gas from Qatar s North field. We own a 30 percent interest in the project. The other participants in the project are affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent). Our interest is held through a jointly owned company, Qatar Liquefied Gas Company Limited (3), for which we use the equity method of accounting. Qatargas 3 secured project financing of $4 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. Prior to project completion certification, all loans, including the ConocoPhillips loan facilities, are guaranteed by the participants, based on their respective ownership interests. Accordingly, our maximum exposure to this financing structure is $1.2 billion, excluding accrued interest. Upon completion certification, which is expected in 2010, all project loan facilities, including the ConocoPhillips loan facilities, will become non-recourse to the project participants. At December 31, 2007, Qatargas 3 had $2.4 billion outstanding under all the loan facilities, of which ConocoPhillips provided $690 million, and an additional $43 million of accrued interest.

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Rockies Express Pipeline LLC: In June 2006, we issued a guarantee for 24 percent of the $2.0 billion in credit facilities of Rockies Express Pipeline LLC (Rockies Express), which will be used to construct a natural gas pipeline across a portion of the United States. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $480 million, which could become payable if the credit facility is fully utilized and Rockies Express fails to meet its obligations under the credit agreement. At December 31, 2007, Rockies Express had $1,625 million outstanding under the credit facilities, with our 24 percent guarantee equaling $390 million. In addition, we have a 24 percent guarantee on $600 million of Floating Rate Notes due 2009 issued by Rockies Express in September 2007. It is anticipated that construction completion will be achieved in 2009, and refinancing will take place at that time, making the debt non-recourse. For additional information, see Note 7 Variable Interest Entities (VIEs), in the Notes to Consolidated Financial Statements.

Keystone Oil Pipeline: In December 2007, we acquired a 50 percent equity interest in the Keystone Oil Pipeline (Keystone), a joint venture with TransCanada Corporation. Keystone plans to construct a crude oil pipeline originating in Alberta, with delivery points in Illinois and Oklahoma. In connection with certain planning and construction activities, agreements were put in place with third parties to guarantee the payments due under those agreements. Our maximum potential amount of future payments under those agreements are estimated to be $400 million, which could become payable if Keystone fails to meet its obligations under the agreements noted above and the obligation cannot otherwise be mitigated. Payments under the guarantees are contingent upon the partners not making necessary equity contributions into Keystone; therefore, it is considered unlikely that payments would be required. All but $15 million of the guarantees will terminate after construction is completed, currently estimated to be in 2010.

For additional information about guarantees, see Note 17 Guarantees, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Capital Requirements

For information about our capital expenditures and investments, see the Capital Spending section.

Our debt balance at December 31, 2007, was $21.7 billion, a decrease of $5.4 billion during 2007, and our debt-to-capital ratio was 19 percent at year-end 2007. Our debt-to-capital ratio at the end of 2008 will depend on realized commodity prices and margins, the funding of our capital program, and the level of our dividends and share repurchases. Our current debt-to-capital target is 20 percent to 25 percent.

Effective January 15, 2007, we redeemed the 8% Junior Subordinated Deferrable Interest Debentures due 2037, at a premium of $14 million, plus accrued interest. This redemption resulted in the immediate redemption by Phillips 66 Capital II of $350 million of 8% Capital Securities. See Note 15 Debt, in the Notes to Consolidated Financial Statements, for additional information.

Also, in January 2007, we redeemed our $153 million 7.25% Notes due 2007 upon their maturity. In February 2007, we reduced our Floating Rate Five-Year Term Note due 2011 from $5 billion to $4 billion, with a subsequent reduction in July 2007 to $3 billion. In April 2007, we redeemed our $1 billion Floating Rate Notes due 2007 upon their maturity. In October 2007, we redeemed $300 million of ConocoPhillips Australia Funding Company s Floating Rate Notes due 2009 at par plus accrued interest.

In May 2007, Polar Tankers Inc., a wholly owned subsidiary, issued $645 million of 5.951% Notes due 2037. The notes are fully and unconditionally guaranteed by ConocoPhillips and ConocoPhillips Company.

In December 2007, we terminated interest rate swaps on $350 million of our 4.75% Notes due 2012. No interest rate swaps remain on any of our debt.

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In January 2008, we repaid $1 billion of our Floating Rate Five-Year Term Note due 2011, reducing the balance outstanding to $2 billion. In February 2008, we gave notice to redeem in March 2008 our $300 million 7.125% Debentures due 2028 at 102.7 percent, plus accrued interest.

On January 3, 2007, we closed on a business venture with EnCana. As part of this transaction, we are obligated to contribute $7.5 billion, plus accrued interest, over a ten-year period, beginning in 2007, to the upstream business venture, FCCL Oil Sands Partnership, formed as a result of the transaction. An initial contribution of $188 million was made upon closing in January. Quarterly principal and interest payments of $237 million began in the second quarter of 2007, and will continue until the balance is paid. Of the principal obligation amount, approximately $593 million is short-term and is included in the Accounts payable related parties line on our consolidated balance sheet. The principal portion of these payments, which totaled $425 million in 2007, is presented on our consolidated statement of cash flows as an other financing activity. 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 an additional capital contribution and is included in the Capital expenditures and investments line on our consolidated statement of cash flows.

On July 9, 2007, we announced plans to repurchase up to $15 billion of our common stock through the end of 2008. This amount included $2 billion remaining under a previously announced program. During 2007, we repurchased 89.5 million shares of our common stock at a cost of $7.0 billion, including 177,110 shares at a cost of $14 million from a consolidated Burlington Resources grantor trust. We anticipate first-quarter 2008 share repurchases to be $2 billion to $3 billion.

In December 2005, we entered into a credit agreement with Qatargas 3, whereby we will provide loan financing of approximately $1.2 billion for the construction of an LNG train in Qatar. This financing will represent 30 percent of the project s total debt financing. Through December 31, 2007, we had provided $690 million in loan financing, and an additional $43 million of accrued interest. See the Off-Balance Sheet Arrangements section for additional information on Qatargas 3.

In 2004, we finalized our transaction with Freeport LNG Development, L.P. (Freeport LNG) to participate in a proposed LNG receiving terminal in Quintana, Texas. Construction began in early 2005. We do not have an ownership interest in the facility, but we do have a 50 percent interest in the general partnership managing the venture, along with contractual rights to regasification capacity of the terminal. We entered into a credit agreement with Freeport LNG to provide loan financing of approximately $631 million, excluding accrued interest, for the construction of the facility. Through December 31, 2007, we had provided $594 million in loan financing, and an additional $87 million of accrued interest.

In the fall of 2004, ConocoPhillips and LUKOIL agreed to the expansion of the Varandey terminal as part of our investment in the OOO Naryanmarneftegaz (NMNG) joint venture. We have an obligation to provide loan financing to Varandey Terminal Company for 30 percent of the costs of the terminal expansion, but we will have no governance or ownership interest in the terminal. We estimate our total loan obligation for the terminal expansion to be approximately $416 million at current exchange rates, excluding interest to be accrued during construction. This amount will be adjusted as the project s cost estimate and schedule are updated and the ruble exchange rate fluctuates. Through December 31, 2007, we had provided $331 million in loan financing, and an additional $32 million of accrued interest.

Our loans to Qatargas 3, Freeport LNG and Varandey Terminal Company are included in the Loans and advances related parties line on the balance sheet.

In February 2008, we announced a quarterly dividend of 47 cents per share, representing a 15 percent increase over the previous quarter s dividend of 41 cents per share. The dividend is payable March 3, 2008, to stockholders of record at the close of business February 25, 2008.

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Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2007:

	Millions of Dollars				
	Payments Due by Period				
	Total	Up to 1 Year	Year 2-3	Year 4-5	After 5 Years
Debt obligations (a)	$ 21,633	1,368	2,796	7,243	10,226
Capital lease obligations	54	30	7	-	17
Total debt	21,687	1,398	2,803	7,243	10,243
Interest on debt and other obligations	15,439	1,429	2,608	1,949	9,453
Operating lease obligations	3,308	732	1,032	737	807
Purchase obligations (b)	125,507	49,929	11,864	8,665	55,049
Joint venture acquisition obligation (c)	6,887	593	1,285	1,427	3,582
Other long-term liabilities (d)					
Asset retirement obligations	6,613	253	555	481	5,324
Accrued environmental costs	1,089	187	319	114	469
Unrecognized tax benefits (e)	144	144	(e)	(e)	(e)
Total	$ 180,674	54,665	20,466	20,616	84,927

(a) Includes $688 million of net unamortized premiums and discounts. See Note 15 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. The majority of the purchase obligations are market-based contracts. Includes: (1) our commercial activities of $74,446 million, of which $31,834 million are primarily related to the supply of crude oil to our refineries and the optimization of the supply chain, $10,530 million primarily related to the supply of unfractionated natural gas liquids (NGL) to fractionators, optimization of NGL assets, and for resale to customers, $9,575 million on futures, $8,933 million primarily related to natural gas for resale customers, $7,354 million related to transportation, $4,984 million related to product purchases, $943 million related to power trades, and $293 million related to the purchase side of exchange agreements; (2) $45,744 million of purchase commitments for products, mostly natural gas and NGL, from CPChem over the remaining term of 92 years; and (3) purchase commitments for jointly owned fields and facilities where we are the operator, of which some of the obligations will be reimbursed by our co-venturers in these properties.

Does not include: (1) purchase commitments for jointly owned fields and facilities where we are not the operator; and (2) an agreement to purchase up to 165,000 barrels per day of Venezuelan Merey, or equivalent, crude oil for a market price over a remaining 12-year term if a variety of conditions are met.

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

(d) Does not include: Pensions for the 2008 through 2012 time period, we expect to contribute an average of $335 million per year to our qualified and non-qualified pension and postretirement medical plans in the United

States and an average of $200 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 $460 million for 2008 and then approximately $300 million per year for the remaining four years. Our required minimum funding in 2008 is expected to be $110 million in the United States and $120 million outside the United States.

(e) Does not include unrecognized tax benefits of $999 million because the ultimate disposition and timing of any payments to be made with regard to such amount is 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			
	2008 Budget	**2007**	2006	2005
E&P				
United States Alaska	$ 1,007	**666**	820	746
United States Lower 48	3,259	**3,122**	2,008	891
International	6,787	**6,147**	6,685	5,047
	11,053	**9,935**	9,513	6,684
Midstream	6	**5**	4	839
R&M				
United States	2,060	**1,146**	1,597	1,537
International	741	**240**	1,419	201
	2,801	**1,386**	3,016	1,738
LUKOIL Investment	-	**-**	2,715	2,160
Chemicals	-	**-**	-	-
Emerging Businesses	226	**257**	83	5
Corporate and Other	238	**208**	265	194
	$ 14,324	**11,791**	15,596	11,620
United States	$ 6,435	**5,225**	4,735	4,207
International	7,889	**6,566**	10,861	7,413
	$ 14,324	**11,791**	15,596	11,620

Our capital spending for the three-year period ending December 31, 2007, totaled $39.0 billion. During the three-year period, 67 percent of total spending went to our E&P segment. In addition to our capital expenditures and investments spending during 2007 and 2006, we also provided loans of approximately $700 million and $800 million, respectively, to certain related parties.

Our capital expenditures and investments budget for 2008 is $14.3 billion. Included in this amount is approximately $700 million in capitalized interest. We plan to direct 77 percent of the capital expenditures and investments budget to E&P and 20 percent to R&M. With the addition of loans to certain affiliated companies and principal contributions related to funding our portion of the EnCana transaction, our total capital program for 2008 is approximately $15.3 billion. See the Capital Requirements section, as well as Note 10 Investments, Loans and Long-Term Receivables and Note 16 Joint Venture Acquisition Obligation, in the Notes to Consolidated Financial Statements, for additional information.

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E&P

Capital spending for E&P during the three-year period ending December 31, 2007, totaled $26.1 billion. The expenditures over this period supported key exploration and development projects including:

- Development drilling in the Greater Kuparuk Area, including West Sak; the Greater Prudhoe Bay Area; the Alpine field, including satellite field prospects; exploratory drilling; and the acquisition of acreage in Alaska.
- Oil and natural gas developments in the Lower 48 states, including New Mexico, Texas, Louisiana, Oklahoma, Montana, North Dakota and Colorado.
- The Magnolia development, Ursa and K-2 fields in the deepwater Gulf of Mexico.
- The acquisition of limited-term, fixed-volume overriding royalty interests in Utah and the San Juan Basin related to our natural gas production.
- Investment in the West2East Pipeline LLC (West2East), a company holding a 100 percent interest in Rockies Express Pipeline LLC (Rockies Express).
- Expansion of the Syncrude oil sands project, the development of the Surmont heavy-oil project, capital expenditures related to the EnCana upstream business venture, and development of conventional oil and gas reserves, all in Canada.
- Development of the Corocoro field offshore Venezuela (see Note 13 Impairments, in the Notes to Consolidated Financial Statements, for additional information).
- The Ekofisk Area growth project and Alvheim project in the Norwegian North Sea.
- The Statfjord Late-Life project straddling the offshore boundary between Norway and the United Kingdom.
- The Britannia satellite and Clair developments in the U.K. North Sea and Atlantic Margin, respectively.
- An integrated project to produce and liquefy natural gas from Qatar s North field.
- Investments in three fields in Algeria.
- Expenditures related to the terms under which we returned to our former oil and natural gas production operations in the Waha concessions in Libya and continued development of these concessions.
- Ongoing development of onshore oil and natural gas fields in Nigeria and ongoing exploration activities both onshore and on deepwater leases.
- The Kashagan field and satellite prospects in the Caspian Sea, offshore Kazakhstan.
- The acquisition of an interest in OOO Naryanmarneftegaz (NMNG), a joint venture with LUKOIL, and development of the Yuzhno Khylchuyu (YK) field.
- The Bayu-Undan gas recycle and liquefied natural gas development projects in the Timor Sea and northern Australia, respectively.
- The Belanak, Suban, Kerisi, Hiu and Belut projects in Indonesia.

The Peng Lai 19-3 development in China s Bohai Bay and additional Bohai Bay appraisal and adjacent field prospects.

Expenditures to develop the Su Tu Vang field and continued in-field development of the Rang Dong field in Vietnam.

Capital expenditures for construction of our Endeavour Class tankers, as well as for an upgrade to the Trans-Alaska Pipeline System pump stations were also included in the E&P segment.

2008 CAPITAL EXPENDITURES AND INVESTMENTS BUDGET

E&P s 2008 capital expenditures and investments budget is $11.1 billion, 11 percent higher than actual expenditures in 2007. Thirty-nine percent of E&P s 2008 capital expenditures and investments budget is planned for the United States.

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Capital spending for our Alaskan operations is expected to fund Prudhoe Bay, Greater Kuparuk and western North Slope operations, including the Alpine satellite fields, as well as exploration activities. In addition, we anticipate further development spending in our Cook Inlet Area. As a result of increased production taxes enacted by the state of Alaska in the fourth quarter of 2007, we anticipate our 2008 capital expenditures will be less than originally planned, mainly related to reduced project funding on the North Slope of Alaska.

In the Lower 48, capital expenditures will focus primarily on developing natural gas reserves within core areas, including the San Juan Basin of New Mexico and Colorado; the Lobo Trend of south Texas; the Bossier and Cotton Valley Trends of east Texas and north Louisiana; the Barnett Shale Trend of north Texas; the Anadarko Basin of western Oklahoma; and the Piceance Basin in northwest Colorado. We also plan to pursue oil development in the Williston Basin of Montana and North Dakota, as well as oil and gas developments in southern Louisiana and the Permian Basin of West Texas. Offshore capital will be focused mainly on the Ursa development in the Gulf of Mexico. In addition, investments will be made in West2East for Rockies Express.

E&P is directing $6.8 billion of its 2008 capital expenditures and investments budget to international projects. Funds in 2008 will be directed to developing major long-term projects, including the Kashagan project in the Caspian Sea and the YK field in northern Russia, through the NMNG joint venture with LUKOIL; the J-Block fields, the Britannia satellites and the Ekofisk Area in the North Sea; the Bohai Bay project in China; heavy-oil projects in Canada and western Canada natural gas projects; offshore Block B and onshore South Sumatra in Indonesia; fields offshore Malaysia and Vietnam; the Qatargas 3 LNG project in Qatar; and the Waha concessions in Libya.

PROVED UNDEVELOPED RESERVES

The net addition of proved undeveloped reserves accounted for 77 percent, 37 percent and 44 percent of our total net additions in 2007, 2006 and 2005, respectively. During these years, we converted, on average, 16 percent per year of our proved undeveloped reserves to proved developed reserves. Of our 2,921 million total BOE proved undeveloped reserves at December 31, 2007, we estimated that the average annual conversion rate for these reserves for the three-year period ending 2010 will be approximately 18 percent.

Costs incurred for the years ended December 31, 2007, 2006 and 2005, relating to the development of proved undeveloped oil and gas reserves were $6.4 billion, $6.4 billion, and $3.4 billion, respectively. Estimated future development costs relating to the development of proved undeveloped reserves for the years 2008 through 2010 are projected to be $4.5 billion, $3.6 billion, and $2.6 billion, respectively.

Approximately 78 percent of our proved undeveloped reserves at year-end 2007 were associated with 10 major development areas and our investment in LUKOIL. Eight of the major development areas are currently producing and are expected to have proved reserves convert from undeveloped to developed over time as development activities continue and/or production facilities are expanded or upgraded, and include:

- The Ekofisk field in the North Sea.
- The Peng Lai 19-3 field in China.
- Fields in the United States and Canada.
- EnCana business venture projects Christina Lake and Foster Creek.
- The Surmont heavy-oil project in Canada.

The remaining two major projects, Qatargas 3 in Qatar and the Kashagan field in Kazakhstan, will have undeveloped proved reserves convert to developed as these projects begin production.

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Midstream

Capital spending for Midstream during the three-year period ending December 31, 2007, was primarily related to increasing our ownership interest in DCP Midstream in 2005 from 30.3 percent to 50 percent.

R&M

Capital spending for R&M during the three-year period ending December 31, 2007, was primarily for acquiring additional crude oil refining capacity, clean fuels projects to meet new environmental standards, refinery-upgrade projects to improve product yields, the operating integrity of key processing units, as well as for safety projects. In addition, in December 2007, we invested funds to acquire a 50 percent equity interest in the Keystone Oil Pipeline (Keystone), a joint venture to construct a crude oil pipeline from Hardisty, Alberta to U.S. Midwest markets in Illinois and Oklahoma. During this three-year period, R&M capital spending was $6.1 billion, representing 16 percent of our total capital expenditures and investments.

Key projects during the three-year period included:

- Acquisition of the Wilhelmshaven refinery in Germany.
- Debottlenecking of a crude and fluid catalytic cracking unit, and completion of a new sulfur plant at the Ferndale refinery.
- A new ultra-low-sulfur diesel hydrotreater at the Sweeny refinery.
- Revamp of an existing hydrotreater for ultra-low-sulfur diesel and a new hydrogen plant at the Wood River refinery.
- Expansion of existing hydrotreaters for both low-sulfur gasoline and ultra-low-sulfur diesel, with the addition of a new hydrogen plant at the Bayway refinery.
- A new hydrotreater for ultra-low-sulfur diesel and a hydrogen plant at the Ponca City refinery.
- Revamps of existing hydrotreaters for ultra-low-sulfur diesel at the Los Angeles, Trainer and Ferndale refineries.
- A new ultra-low-sulfur diesel hydrotreater and hydrogen plant at the Billings refinery.
- A fluid catalytic cracking gasoline hydrotreater at the Alliance refinery for production of low-sulfur gasoline.
- A sulfur removal technology unit at the Lake Charles refinery for the production of low-sulfur gasoline.
- A new ultra-low-sulfur diesel hydrotreater at the Rodeo facility of our San Francisco refinery.

Major construction activities in progress include:

- Expansion of a hydrocracker at the Rodeo facility of our San Francisco refinery.
- Construction of a low-sulfur gasoline project at the Billings refinery.
- U.S. programs aimed at air emission reductions.

Internationally, we continued to invest in our ongoing refining and marketing operations to upgrade and increase the profitability of our existing assets, including upgrading the distillate desulfurization capabilities at our Humber refinery in the United Kingdom.

2008 CAPITAL EXPENDITURES AND INVESTMENTS BUDGET

R&M s 2008 capital budget is $2.8 billion, a 102 percent increase from actual spending in 2007. Domestic spending in 2008 is expected to comprise 74 percent of the R&M budget.

We plan to direct about $1.6 billion of the R&M capital budget to domestic refining, primarily for projects related to sustaining and improving the existing business with a focus on reliability, energy efficiency, capital maintenance and regulatory compliance. Work continues at a number of refineries on projects to

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increase crude oil capacity, expand conversion capability and increase clean product yield. Our North American transportation and marketing businesses are expected to spend about $800 million, including investments in the Keystone project.

Outside North America, we plan to spend about $400 million, with a focus on projects related to reliability, safety and the environment, as well as an upgrade project at the Wilhelmshaven, Germany, refinery and the advancement of a full-conversion refinery project in Yanbu, Saudi Arabia.

LUKOIL Investment

Capital spending in our LUKOIL Investment segment during the three-year period ending December 31, 2007, was for continued purchases of ordinary shares of LUKOIL to increase our ownership interest. However, no additional purchases were made in 2007, and none are expected in 2008.

Emerging Businesses

Capital spending for Emerging Businesses during the three-year period ending December 31, 2007, was primarily for an expansion of the Immingham combined heat and power cogeneration plant near the company s Humber refinery in the United Kingdom. In addition, in October 2007, we purchased a 50 percent interest in Sweeny Cogeneration LP (SCLP). SCLP provides steam and electric power to the Sweeny refinery complex with any excess power sold into the market. We account for this joint venture using the equity method of accounting.

Contingencies

Legal and Tax Matters

We accrue for non-income-tax-related contingencies when a loss is probable and the amounts can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. In the case of income-tax-related contingencies, we adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48), effective January 1, 2007. FIN 48 requires a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain. Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements.

Environmental

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

- Federal Clean Air Act, which governs air emissions.

- Federal Clean Water Act, which governs discharges to water bodies.

- 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 threatened to occur.

- Federal Resource Conservation and Recovery Act (RCRA), which governs the treatment, storage, and disposal of solid waste.

- 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.

Federal Emergency Planning and Community Right-to-Know Act (EPCRA), which requires facilities to report toxic chemical inventories with local emergency planning committees and responses departments.

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.

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

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

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

For example, the Energy Policy Act of 2005 imposed obligations to provide increasing volumes on a percentage basis of renewable fuels in transportation motor fuels through 2012. These obligations were changed with the enactment of the Energy Independence & Security Act of 2007, which was signed in late December. The new law requires fuel producers and importers to provide approximately 66 percent more renewable fuels in 2008 as compared with amounts set forth in the Energy Policy Act of 2005, with increases in amounts of renewable fuels required through 2022. We are in the process of establishing implementation, operating and capital strategies along with advanced technology development to meet these requirements.

Since 1997 when the Kyoto Protocol called for reductions of certain emissions that contribute to increases in atmospheric greenhouse gas concentrations, there have been a range of national, sub-national and international regulations proposed or implemented focusing on greenhouse gas reduction. These actual or proposed regulations do or will apply in countries where we have interests or may have interests in the future. Regulation in this field continues to evolve and while it is likely to be increasingly widespread and stringent, at this stage it is not possible to accurately estimate either a timetable for implementation or our future compliance costs. The overall long-term fiscal impact from this type of regulation is uncertain. Examples of legislation or precursors for possible regulation include:

European Emissions Trading Scheme, the program through which many of the European Union member states are implementing the Kyoto Protocol.

California s Assembly Bill 32, which requires the California Air Resources Board (CARB) to develop regulations and market mechanisms that will ultimately reduce California s greenhouse gas 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. ___, 127 S.Ct. 1438 (2007) confirming that the U.S. Environmental Protection Agency (EPA) has the authority to regulate carbon dioxide as an air pollutant under the federal Clean Air Act.

There is growing consensus that some form of regulation will be forthcoming at the federal level in the United States with respect to greenhouse gas emissions (including carbon dioxide) and such regulation could result in the creation of substantial additional costs in the form of taxes or required acquisition or trading of emission allowances.

Additionally, with the continuing trend toward stricter standards, greater regulation and more extensive permitting requirements, our capital and operating environmental expenditures are likely to be substantial and may increase in the future. We may experience significant delays in obtaining all required environmental regulatory permits or other approvals that we need to operate or upgrade our existing facilities or construct new facilities. If there is a delay in obtaining any required environmental regulatory approvals or permits, the operation of our facilities may be interrupted or become subject to additional costs.

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. Future environmental expenditures associated with the remediation of MTBE-contaminated underground storage tank sites could be substantial.

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. Over the next decade, we anticipate that significant ongoing 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, 2006, we reported we had been notified of potential liability under CERCLA and comparable state laws at 64 sites around the United States. At December 31, 2007, we had resolved five of these sites and had received nine new notices of potential liability, leaving 68 unresolved sites where we have been notified of potential liability.

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

Expensed environmental costs were $1,025 million in 2007 and are expected to be about $1.1 billion in 2008 and 2009. Capitalized environmental costs were $785 million in 2007 and are expected to be about $1.2 billion and $1.1 billion in 2008 and 2009, respectively.

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

Many of these liabilities result from CERCLA, RCRA and similar state laws that require us to undertake certain investigative and remedial activities at sites where we conduct, or once conducted, operations or at sites where ConocoPhillips-generated waste was disposed. The accrual also includes a number of sites we identified that may require environmental remediation, but which are not currently the subject of CERCLA, RCRA or state enforcement activities. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the future, we may incur significant costs under both CERCLA and RCRA. Considerable uncertainty exists with respect to these costs, and under adverse changes in circumstances, potential liability may exceed amounts accrued as of December 31, 2007.

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, 2007, our balance sheet included total accrued environmental costs of $1,089 million, compared with $1,062 million at December 31, 2006. We expect to incur a substantial majority of these expenditures within the next 30 years.

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

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. Uncertainties that may affect the realization of these assets include tax law changes and the future level of product prices and costs. Based on our historical taxable income, our expectations for the future, and available tax-planning strategies, management expects

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that the net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as reductions in future taxable income.

NEW ACCOUNTING STANDARDS

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This Statement defines fair value, establishes a framework for its measurement and expands disclosures about fair value measurements. We use fair value measurements to measure, among other items, purchased assets and investments, derivative contracts and financial guarantees. We also use them to assess impairment of properties, plants and equipment, intangible assets and goodwill. The Statement does not apply to share-based payment transactions and inventory pricing. In February 2008, the FASB issued a FASB Staff Position (FSP) on Statement No. 157 that permits a one-year delay of the effective date for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We will adopt this Statement effective January 1, 2008, with the exceptions allowed under the FSP described above and do not expect any significant impact to our consolidated financial statements, other than additional disclosures.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115. This Statement permits an entity to choose to measure financial instruments and certain other items similar to financial instruments at fair value, with all subsequent changes in fair value for the financial instrument reported in earnings. By electing the fair value option in conjunction with a derivative, an entity can achieve an accounting result similar to a fair value hedge without having to comply with complex hedge accounting rules. We will adopt this Statement effective January 1, 2008, and do not expect any significant impact to our consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141 (Revised), Business Combinations (SFAS No. 141(R)). This Statement will apply to all transactions in which an entity obtains control of one or more other businesses. In general, SFAS No. 141(R) requires the acquiring entity in a business combination to recognize the fair value of all the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date as the fair value measurement point; and modifies the disclosure requirements. This Statement applies prospectively to business combinations for which the acquisition date is on or after January 1, 2009. However, accounting for changes in valuation allowances for acquired deferred tax assets and the resolution of uncertain tax positions for prior business combinations will impact tax expense instead of impacting the prior business combination accounting starting January 1, 2009. We are currently evaluating the changes provided in this Statement.

Also in December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51, which changes the classification of non-controlling interests, sometimes called a minority interest, in the consolidated financial statements. Additionally, this Statement establishes a single method of accounting for changes in a parent company s ownership interest that do not result in deconsolidation and requires a parent company to recognize a gain or loss when a subsidiary is deconsolidated. This Statement is effective January 1, 2009, and will be applied prospectively with the exception of the presentation and disclosure requirements which must be applied retrospectively for all periods presented. We are currently evaluating the impact on our consolidated financial statements.

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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 2007, 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 $1,385 million and the accumulated impairment reserve was $429 million. The weighted average judgmental percentage probability of ultimate failure was approximately 65 percent and the weighted average amortization period was approximately 2.1 years. If that judgmental percentage were to be raised by 5 percent across all calculations, pretax leasehold impairment expense in 2008 would increase by approximately $29 million. The remaining $4,134 million of capitalized unproved property costs at year-end 2007 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 billion is concentrated in 10 major assets. Management expects less than $50 million to move to proved properties in 2008. Most of the $2 billion is associated with North America and Asia Pacific natural gas projects and North America oil-sands projects, on which we continue to work with co-venturers and regulatory agencies to develop.

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.

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. 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 the company is actively pursuing such approvals and permits and believes 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 we seek government or co-venturer approval of development plans or seek environmental permitting. 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 2007, total suspended well costs were $589 million, compared with $537 million at year-end 2006. For additional information on suspended wells, including an aging analysis, see Note 11 Properties, Plants and Equipment, in the Notes to Consolidated Financial Statements.

Proved Oil and Gas Reserves and Canadian Syncrude Reserves

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

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

All of our proved crude oil, natural gas and natural gas liquids reserves held by consolidated companies have been estimated by ConocoPhillips. Our policy with respect to equity affiliates is either to estimate the proved reserve quantities ourselves (applicable to those situations where we have a substantial engineering presence), or to rely on estimates prepared by the equity affiliate, and perform a reasonableness review of those assessments. Of the proved reserves attributable to equity affiliates at year-end 2007, 38 percent was based on assessments of the available data performed by ConocoPhillips. The remaining 62 percent, reflecting our equity interest in LUKOIL, was based on estimates prepared by the equity affiliate. These equity-affiliate-prepared estimates are reviewed by ConocoPhillips and adjusted to comply with our internal reserves governance policies.

Proved reserve estimates are updated annually and take into account recent production and sub-surface information about each field or oil sand mining operation. Also, as required by authoritative guidelines, the estimated future date when a field or oil sand mining operation will be permanently shut down for economic reasons is based on an extrapolation of sales prices and operating costs prevalent at the balance sheet date. This estimated date when production will end affects the amount of estimated recoverable 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 go up then our applicable reserve quantities would decline.

The judgmental estimation of proved reserves also is important to the income statement because the proved oil and gas reserve estimate for a field or the estimated in-place crude bitumen volume for an oil sand mining operation 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 2007, the net book value of productive E&P properties, plants and equipment subject to a unit-of-production calculation, including our Canadian Syncrude bitumen oil sand assets, was approximately $63 billion and the depreciation, depletion and amortization recorded on these assets in 2007 was approximately $6.9 billion. The estimated proved developed oil and gas reserves on these fields were 6.4 billion BOE at the beginning of 2007 and were 6.1 billion BOE at the end of 2007. The estimated proved reserves on the Canadian Syncrude assets were 243 million barrels at the beginning of 2007 and were 221 million barrels at the end of 2007. If the judgmental 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 2007 would have been increased by an estimated $361 million. Impairments of producing oil and gas properties in 2007, 2006 and 2005 totaled $471 million, $215 million and $4 million, respectively. Of these write-downs, $76 million in 2007, $131 million in 2006 and $1 million in 2005 were due to downward revisions of proved reserves.

Impairment of Assets

Long-lived assets 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. 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, at an entire complex level for downstream assets, or at a site level for retail stores. Because there usually is a lack of quoted market prices for long-lived assets, the fair value usually is based on the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group. The expected future cash flows

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used for impairment reviews and related fair value calculations are based on judgmental assessments of future production volumes, prices and costs, considering all available information at the date of review. See Note 13 Impairments, in the Notes to Consolidated Financial Statements, for additional information.

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 are changing constantly, as well as political, environmental, safety and public relations considerations.

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

See Note 1 Accounting Policies, Note 14 Asset Retirement Obligations and Accrued Environmental Costs, and Note 18 Contingencies and Commitments, in the Notes to Consolidated Financial Statements, for additional information.

Business Acquisitions

Purchase Price Allocation

Accounting for the acquisition of a business requires the allocation of the purchase price to the various assets and liabilities of the acquired business. For most assets and liabilities, purchase price allocation is accomplished by recording the asset or liability at its estimated fair value. The most difficult estimations 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 finish these fair value determinations and finalize the purchase price allocation.

Intangible Assets and Goodwill

At December 31, 2007, we had $731 million of intangible assets determined to have indefinite useful lives, thus they are not amortized. This judgmental assessment of an indefinite useful life has to be continuously evaluated in the future. If, due to changes in facts and circumstances, management determines that these intangible assets then 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. See Note 12 Goodwill and Intangibles, in the Notes to Consolidated Financial Statements, for additional information.

At December 31, 2007, we had $29.3 billion of goodwill recorded in conjunction with past business combinations. Under the accounting rules for goodwill, this intangible asset is not amortized. Instead, goodwill is subject to annual reviews for impairment at a reporting unit level. The reporting unit or units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed. A reporting unit is an operating segment or a component that is one level below an operating segment. Prior to 2007, within our E&P and our R&M segments, we determined we had one and two reporting units, respectively, for purposes of assigning goodwill and testing for impairment. These were Worldwide Exploration and Production, Worldwide Refining and Worldwide Marketing. In December 2006, we announced a new business strategy for Worldwide Marketing to shift most of our marketing operations to a wholesale channel of trade and significantly increase the level of vertical integration between our refining and wholesale marketing operations. Because of this new business strategy, we plan to dispose of most of the retail outlets we operate or own. During 2007, the execution of this new business strategy was well under way and is expected to be fully in place by the end of 2008. In accordance with SFAS No. 142, Goodwill and Other Intangible Assets (SFAS No. 142), we have reassessed the reporting unit definitions within the R&M segment based on this new business strategy and have concluded that the refining and marketing components within the R&M segment now are economically similar enough to be aggregated into one reporting unit, Worldwide Refining and Marketing, beginning in 2007. No goodwill impairment would have been required in 2007 had we retained Worldwide Marketing as a separate reporting unit.

If we later reorganize our businesses or management structure so that the components within our two reporting units are no longer economically similar, the reporting units would be revised and goodwill would be re-assigned using a relative fair value approach in accordance with SFAS No. 142. Goodwill impairment testing at a lower reporting unit level could result in the recognition of impairment that would not otherwise be recognized at the current higher level of aggregation. In addition, the sale or disposition of a portion of these two reporting units will be allocated a portion of the reporting unit s goodwill, based on relative fair values, which will adjust the amount of gain or loss on the sale or disposition. When assessing the need for impairments on those sales and disposals, we take into consideration the anticipated allocation of goodwill and provisionally provide for its expected impairment upon final sale or disposal.

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 periodic 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 and observed market multiples of operating cash flows and net income. In addition, if the estimated fair value of a reporting unit is less than the book value (including the goodwill), further judgment must be applied in determining the fair values of individual assets and liabilities for purposes of the hypothetical purchase price allocation. Again, management must use all available information to make these fair value determinations. At year-end 2007, the estimated fair values of our Worldwide Exploration and Production and Worldwide Refining and Marketing reporting units ranged from between 44 percent to 65 percent higher than recorded net book values (including goodwill) of the reporting units. However, a lower fair value estimate in the future for any of these reporting units could result in an impairment.

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 income statement. This also impacts the required company contributions into the plans. 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. 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

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determining required company contributions into plan assets. 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 would increase annual benefit expense by $100 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $55 million. In determining the discount rate, we use yields on high-quality fixed income investments (including among other things, Moody s Aa corporate bond yields) with adjustments as needed to match the estimated benefit cash flows of our plans.

OUTLOOK

Alaska

In late 2007, we submitted a proposal to the governor of Alaska to advance the development of the Alaska Natural Gas Pipeline Project. The proposed pipeline would transport approximately 4 billion cubic feet per day of natural gas from the Alaska North Slope to markets in Canada and the United States. We have a 36.1 percent non-operator interest in the Greater Prudhoe Area fields that are expected to be a primary source of natural gas to be shipped in the proposed pipeline. Our proposal was submitted as an alternative to the process the Alaska Legislature established in its Alaska Gasline Inducement Act (AGIA). In our proposal, we stated our willingness to make significant investments, without state matching funds, to advance this project. In January 2008, we received a letter from the governor of Alaska stating our alternative does not give the state a reason to deviate from the AGIA process. We formally responded to the governor s letter on January 24, 2008. As a result of the lack of engagement by the state of Alaska on our proposal, we are reassessing how best to advance the Alaska natural gas pipeline project. During this reassessment, as an initial step we will continue planning and contracting efforts in preparation for route reconnaissance and environmental studies starting in June 2008. We expect to continue to testify before the Alaska Legislature and engage the Alaska public with our view of the best path forward to advance the gas pipeline project.

Venezuela

Negotiations continue between ConocoPhillips and Venezuelan authorities concerning appropriate compensation for the expropriation of the company s oil interests. We continue to preserve all our rights with respect to this situation, including our rights under the contracts we signed and under international and Venezuelan law. We continue to evaluate our options in realizing adequate compensation for the value of our oil investments and operations in Venezuela and filed a request for international arbitration on November 2, 2007, with the International Centre for Settlement of Investment Disputes (ICSID), an arm of the World Bank. The request was registered by ICSID on December 13, 2007.

Canada

On October 25, 2007, the Alberta provincial government publicly announced its intention to make a change to the royalty structure for Crown lands, effective January 1, 2009. Although the government s proposed change will require legislative and regulatory amendments to become effective and may be further modified before final adoption, there is a high likelihood there will be some form of change to the royalty structure in Alberta. While the precise impact of the proposed change is not determinable at this time, the adoption of the proposed royalty structure could result in a range of outcomes, including a negative adjustment to our Canadian reserve base. This change will impact both our conventional western Canada natural gas business and our oil sands operations.

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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, continue, could, intend, may, plan, potential, predict, should, wi projection, forecast, goal, guidance, outlook, effort, target and similar expressions.

We based the forward-looking statements relating to our operations 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 and involve risks, uncertainties and assumptions we cannot predict. In addition, we based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual outcomes and results may differ materially from what we have expressed or forecast in the forward-looking statements. Any differences could result from a variety of factors, including the following:

Fluctuations in crude oil, natural gas and natural gas liquids prices, refining and marketing margins and margins for our chemicals business.

Potential failure or delays in achieving expected reserve or production levels from existing and future oil and gas development projects due to operating hazards, drilling risks and the inherent uncertainties in predicting oil and gas reserves and oil and gas reservoir performance.

Unsuccessful exploratory drilling activities or the inability to obtain access to exploratory acreage.

Failure of new products and services to achieve market acceptance.

Unexpected changes in costs or technical requirements for constructing, modifying or operating facilities for exploration and production projects, manufacturing or refining.

Unexpected technological or commercial difficulties in manufacturing, refining, or transporting our products, including synthetic crude oil and chemicals products.

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

Inability to timely obtain or maintain permits, including those necessary for construction of LNG terminals or regasification facilities, 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 LNG and refinery projects and related facilities.

Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, political events or terrorism.

International monetary conditions and exchange controls.

Substantial investment or reduced demand for products as a result of existing or future environmental rules and regulations.

Liability for remedial actions, including removal and reclamation obligations, under environmental regulations.

Liability resulting from litigation.

General domestic and international economic and political developments, including: armed hostilities; expropriation of assets; changes in governmental policies relating to crude oil, natural gas, natural gas liquids or refined product pricing, regulation, or taxation; other political, economic or diplomatic developments; and international monetary fluctuations.

Changes in tax and other laws, regulations (including alternative energy mandates), or royalty rules applicable to our business.

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 the Risk Factors section included in Items 1 and 2 Business and Properties in this report.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Financial Instrument Market Risk

We and certain of our subsidiaries hold and issue derivative contracts and financial instruments that expose our cash flows or earnings to changes in commodity prices, foreign exchange rates or interest rates. We may use financial and commodity-based derivative contracts to manage the risks produced by changes in the prices of electric power, natural gas, crude oil and related products, fluctuations in interest rates and foreign currency exchange rates, or to exploit 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 without approval from the Chief Executive Officer. The Authority Limitations document also authorizes the Chief Executive Officer to establish the maximum 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, while the Senior Vice President of Commercial monitors commodity price risk. Both report to the Chief Executive Officer. The Commercial organization manages our commercial marketing, optimizes our commodity flows and positions, monitors related risks of our upstream and downstream businesses, and selectively takes price risk to add value.

Commodity Price Risk

We operate in the worldwide crude oil, refined products, natural gas, natural gas liquids, and electric power markets and are exposed to fluctuations in the prices for these commodities. These fluctuations can affect our revenues, as well as the cost of operating, investing, and financing activities. Generally, our policy is to remain exposed to the market prices of commodities; however, executive management may elect to use derivative instruments to hedge the price risk of our crude oil and natural gas production, as well as refinery margins.

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

- Balance physical systems. In addition to cash settlement prior to contract expiration, exchange traded futures contracts also may be settled by physical delivery of the commodity, providing another source of supply to meet our refinery requirements or marketing demand.

- Meet customer needs. Consistent with our policy to generally remain exposed to market prices, we use swap contracts to convert fixed-price sales contracts, which are often requested by natural gas and refined product consumers, to a floating market price.

- Manage the risk to our cash flows from price exposures on specific crude oil, natural gas, refined product and electric power transactions.

- Enable us to use the market knowledge gained from these activities to do a limited amount of trading not directly related to our physical business. For the years ended December 31, 2007 and 2006, the gains or losses from this activity were not material to our cash flows or net income.

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, 2007, as derivative instruments in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS No. 133). Using Monte Carlo simulation, a 95 percent confidence level and a one-day holding period, the VaR for those

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instruments issued or held for trading purposes at December 31, 2007 and 2006, was immaterial to our net income and cash flows. The VaR for instruments held for purposes other than trading at December 31, 2007 and 2006, was also immaterial to our net income and cash flows.

Interest Rate Risk

The following tables provide information about our financial instruments that are sensitive to changes in short-term U.S. interest rates. The debt table presents principal cash flows and related weighted-average interest rates by expected maturity dates. Weighted-average variable rates are based on implied forward rates in the yield curve at the reporting date. The carrying amount of our floating-rate debt approximates its fair value. The fair value of the fixed-rate financial instruments is estimated based on quoted market prices.

	Millions of Dollars Except as Indicated			
	Debt			
Expected Maturity Date	Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Average Interest Rate
Year-End 2007				
2008	$ **324**	**7.12%**	$ **1,000**	**5.58%**
2009	**313**	**6.44**	**950**	**5.47**
2010	**1,433**	**8.85**	**-**	**-**
2011	**3,175**	**6.74**	**2,000**	**5.58**
2012	**1,267**	**4.94**	**743**	**5.43**
Remaining years	**9,082**	**6.68**	**658**	**4.36**
Total	$ **15,594**		$ **5,351**	
Fair value	$ **17,750**		$ **5,351**	
Year-End 2006				
2007	$ 557	7.43%	$ 1,000	5.37%
2008	32	6.96	-	-
2009	307	6.43	1,250	5.47
2010	1,433	8.85	-	-
2011	3,175	6.74	7,944	5.53
Remaining years	9,983	6.57	691	4.29
Total	$ 15,487		$ 10,885	
Fair value	$ 16,856		$ 10,885	

At the beginning of 2007, we held interest rate swaps that converted $350 million of debt from fixed to floating rate. Under SFAS No. 133, these swaps were designated as hedging the exposure to changes in the fair value of $350 million of 4.75% Notes due 2012. This hedge was terminated in December 2007, when we sold our positions in the swaps for approximately $3 million.

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The following table presents principal cash flows of the fixed-rate 5.3 percent joint venture acquisition obligation owed to FCCL Oil Sands 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 2007 effective yield rate of 4.9 percent, 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	
	Joint Venture Acquisition Obligation	
Expected Maturity Date	Fixed Rate Maturity	Average Interest Rate
Year-End 2007		
2008	**$ 593**	**5.30%**
2009	**626**	**5.30**
2010	**659**	**5.30**
2011	**695**	**5.30**
2012	**732**	**5.30**
Remaining years	**3,582**	**5.30**
Total	**$ 6,887**	
Fair value	**$ 7,031**	

Foreign Currency Risk

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

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At December 31, 2007 and 2006, we held foreign currency swaps hedging short-term intercompany loans between European subsidiaries and a U.S. subsidiary. Although these swaps hedge exposures to fluctuations in exchange rates, we elected not to utilize hedge accounting as allowed by SFAS No. 133. As a result, the change in the fair value of these foreign currency swaps is recorded directly in earnings. Since the gain or loss on the swaps is offset by the gain or loss from remeasuring the intercompany loans into the functional currency of the lender or borrower, there would be no material impact to income from an adverse hypothetical 10 percent change in the December 31, 2007 or 2006, exchange rates. The notional and fair market values of these positions at December 31, 2007 and 2006, were as follows:

		In Millions			
Foreign Currency Swaps		Notional*		Fair Market Value**	
		2007	2006	**2007**	2006
Sell U.S. dollar, buy euro	USD	**744**	242	**$ 3**	5
Sell U.S. dollar, buy British pound	USD	**1,049**	647	**(16)**	20
Sell U.S. dollar, buy Canadian dollar	USD	**1,195**	1,367	**13**	(19)
Sell U.S. dollar, buy Czech koruna	USD	**-**	7	**-**	-
Sell U.S. dollar, buy Danish krone	USD	**20**	17	**-**	-
Sell U.S. dollar, buy Norwegian kroner	USD	**779**	1,145	**15**	15
Sell U.S. dollar, buy Swedish krona	USD	**11**	108	**-**	-
Sell U.S. dollar, buy Slovakia koruna	USD	**-**	2	**-**	-
Sell U.S. dollar, buy Hungary forint	USD	**-**	4	**-**	-
Sell euro, buy Norwegian kroner	EUR	**-**	10	**-**	-
Sell euro, buy Canadian dollar	EUR	**58**	-	**-**	-
Buy euro, sell British pound	EUR	**1**	125	**3**	-

**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 19 Financial Instruments and Derivative Contracts, in the Notes to Consolidated Financial Statements.

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONOCOPHILLIPS

INDEX TO FINANCIAL STATEMENTS

INDEX TO FINANCIAL STATEMENT SCHEDULES

All other schedules are omitted because they are either not required, not significant, not applicable or the information is shown in another schedule, the financial statements or in the notes to consolidated financial statements.

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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 that 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, 2007. 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, 2007.

Ernst & Young LLP has issued an audit report on the company s internal control over financial reporting as of December 31, 2007.

/s/ James J. Mulva	/s/ John A. Carrig
James J. Mulva	**John A. Carrig**
Chairman, President and	Executive Vice President, Finance,
Chief Executive Officer	and Chief Financial Officer
February 21, 2008	

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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, 2007 and 2006, and the related consolidated statements of income, changes in common stockholders equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the condensed consolidating financial information and financial statement schedule listed in the Index at Item 8. 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, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, 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 2006 ConocoPhillips adopted Emerging Issues Task Force Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty, and the recognition and disclosure provisions of Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R), and in 2005 ConocoPhillips adopted Financial Accounting Standards Board Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143.

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, 2007, 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 21, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
ERNST & YOUNG LLP
Houston, Texas
February 21, 2008

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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, 2007, 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, 2007, based on the COSO criteria.

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We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2007 consolidated financial statements of ConocoPhillips and our report dated February 21, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
ERNST & YOUNG LLP
Houston, Texas
February 21, 2008

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Consolidated Income Statement **ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2007	2006	2005
Revenues and Other Income			
Sales and other operating revenues*	$ **187,437**	183,650	179,442
Equity in earnings of affiliates	**5,087**	4,188	3,457
Other income	**1,971**	685	465
Total Revenues and Other Income	**194,495**	188,523	183,364
Costs and Expenses			
Purchased crude oil, natural gas and products	**123,429**	118,899	124,925
Production and operating expenses	**10,683**	10,413	8,562
Selling, general and administrative expenses	**2,306**	2,476	2,247
Exploration expenses	**1,007**	834	661
Depreciation, depletion and amortization	**8,298**	7,284	4,253
Impairment expropriated assets	**4,588**	-	-
Impairments	**442**	683	42
Taxes other than income taxes*	**18,990**	18,187	18,356
Accretion on discounted liabilities	**341**	281	193
Interest and debt expense	**1,253**	1,087	497
Foreign currency transaction (gains) losses	**(201)**	(30)	48
Minority interests	**87**	76	33
Total Costs and Expenses	**171,223**	160,190	159,817
Income from continuing operations before income taxes	**23,272**	28,333	23,547
Provision for income taxes	**11,381**	12,783	9,907
Income From Continuing Operations	**11,891**	15,550	13,640
Discontinued operations	**-**	-	(23)
Income before cumulative effect of changes in accounting principles	**11,891**	15,550	13,617
Cumulative effect of changes in accounting principles	**-**	-	(88)
Net Income	$ **11,891**	15,550	13,529
Income (Loss) Per Share of Common Stock *(dollars)*			
Basic			
Continuing operations	$ **7.32**	9.80	9.79
Discontinued operations	**-**	-	(.02)

Before cumulative effect of changes in accounting principles		**7.32**	9.80	9.77
Cumulative effect of changes in accounting principles		**-**	-	(.06)
Net Income	**$**	**7.32**	9.80	9.71
Diluted				
Continuing operations	**$**	**7.22**	9.66	9.63
Discontinued operations		**-**	-	(.02)
Before cumulative effect of changes in accounting principles		**7.22**	9.66	9.61
Cumulative effect of changes in accounting principles		**-**	-	(.06)
Net Income	**$**	**7.22**	9.66	9.55
Average Common Shares Outstanding *(in thousands)*				
Basic		**1,623,994**	1,585,982	1,393,371
Diluted		**1,645,919**	1,609,530	1,417,028
** Includes excise taxes on petroleum products sales:*	***$***	***15,937***	*16,072*	*17,037*

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet **ConocoPhillips**

At December 31	Millions of Dollars	
	2007	2006
Assets		
Cash and cash equivalents	**$ 1,456**	817
Accounts and notes receivable (net of allowance of $58 million in 2007 and $45 million in 2006)	**14,687**	13,456
Accounts and notes receivable related parties	**1,667**	650
Inventories	**4,223**	5,153
Prepaid expenses and other current assets	**2,702**	4,990
Total Current Assets	**24,735**	25,066
Investments and long-term receivables	**31,457**	19,595
Loans and advances related parties	**1,871**	1,118
Net properties, plants and equipment	**89,003**	86,201
Goodwill	**29,336**	31,488
Intangibles	**896**	951
Other assets	**459**	362
Total Assets	**$ 177,757**	164,781
Liabilities		
Accounts payable	**$ 16,591**	14,163
Accounts payable related parties	**1,270**	471
Notes payable and long-term debt due within one year	**1,398**	4,043
Accrued income and other taxes	**4,814**	4,407
Employee benefit obligations	**920**	895
Other accruals	**1,889**	2,452
Total Current Liabilities	**26,882**	26,431
Long-term debt	**20,289**	23,091
Asset retirement obligations and accrued environmental costs	**7,261**	5,619
Joint venture acquisition obligation related party	**6,294**	-
Deferred income taxes	**21,018**	20,074
Employee benefit obligations	**3,191**	3,667
Other liabilities and deferred credits	**2,666**	2,051
Total Liabilities	**87,601**	80,933
Minority Interests	**1,173**	1,202
Common Stockholders Equity		

Common stock (2,500,000,000 shares authorized at $.01 par value)		
Issued (2007 1,718,448,829 shares; 2006 1,705,502,609 shares)		
Par value	**17**	17
Capital in excess of par	**42,724**	41,926
Grantor trusts (at cost: 2007 42,411,331 shares; 2006 44,358,585 shares)	**(731)**	(766)
Treasury stock (at cost: 2007 104,607,149 shares; 2006 15,061,613 shares)	**(7,969)**	(964)
Accumulated other comprehensive income	**4,560**	1,289
Unearned employee compensation	**(128)**	(148)
Retained earnings	**50,510**	41,292
Total Common Stockholders Equity	**88,983**	82,646
Total	**$ 177,757**	164,781

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Cash Flows **ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2007	2006	2005
Cash Flows From Operating Activities			
Net income	**$ 11,891**	15,550	13,529
Adjustments to reconcile net income to net cash provided by continuing operations			
Non-working capital adjustments			
Depreciation, depletion and amortization	**8,298**	7,284	4,253
Impairment expropriated assets	**4,588**	-	-
Impairments	**442**	683	42
Dry hole costs and leasehold impairments	**463**	351	349
Accretion on discounted liabilities	**341**	281	193
Deferred taxes	**(157)**	263	1,101
Undistributed equity earnings	**(1,823)**	(945)	(1,774)
Gain on asset dispositions	**(1,348)**	(116)	(278)
Discontinued operations	**-**	-	23
Cumulative effect of changes in accounting principles	**-**	-	88
Other	**105**	(201)	(139)
Working capital adjustments*			
Decrease in aggregate balance of accounts receivable sold	**-**	-	(480)
Increase in other accounts and notes receivable	**(2,492)**	(906)	(2,665)
Decrease (increase) in inventories	**767**	(829)	(182)
Decrease (increase) in prepaid expenses and other current assets	**487**	(372)	(407)
Increase in accounts payable	**2,772**	657	3,156
Increase (decrease) in taxes and other accruals	**216**	(184)	824
Net cash provided by continuing operations	**24,550**	21,516	17,633
Net cash used in discontinued operations	**-**	-	(5)
Net Cash Provided by Operating Activities	**24,550**	21,516	17,628
Cash Flows From Investing Activities			
Acquisition of Burlington Resources Inc.**	**-**	(14,285)	-
Capital expenditures and investments, including dry hole costs**	**(11,791)**	(15,596)	(11,620)
Proceeds from asset dispositions	**3,572**	545	768
Long-term advances/loans related parties	**(682)**	(780)	(275)
Collection of advances/loans related parties	**89**	123	111
Other	**250**	-	-
Net cash used in continuing operations	**(8,562)**	(29,993)	(11,016)
Net Cash Used in Investing Activities	**(8,562)**	(29,993)	(11,016)

Cash Flows From Financing Activities				
Issuance of debt		**935**	17,314	452
Repayment of debt		**(6,454)**	(7,082)	(3,002)
Issuance of company common stock		**285**	220	402
Repurchase of company common stock		**(7,001)**	(925)	(1,924)
Dividends paid on company common stock		**(2,661)**	(2,277)	(1,639)
Other		**(444)**	(185)	27
Net cash provided by (used in) continuing operations		**(15,340)**	7,065	(5,684)
Net Cash Provided by (Used in) Financing Activities		**(15,340)**	7,065	(5,684)
Effect of Exchange Rate Changes on Cash and Cash Equivalents		**(9)**	15	(101)
Net Change in Cash and Cash Equivalents		**639**	(1,397)	827
Cash and cash equivalents at beginning of year		**817**	2,214	1,387
Cash and Cash Equivalents at End of Year	**$**	**1,456**	817	2,214

**Net of acquisition and disposition of businesses.*
***Net of cash acquired.*
See Notes to Consolidated Financial Statements.

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Consolidated Statement of Changes in Common Stockholders Equity **ConocoPhillips**

	Shares of Common Stock			Millions of Dollars							
				Common Stock							
	Issued	Held in Treasury	Held in Grantor Trusts	Par Value	Capital in Excess of Par	Treasury Stock	Grantor Trusts	Accumulated Other Comprehensive Income	Unearned Employee Compensation	Retained Earnings	Total
December 31, 2004	1,437,729,662	-	48,182,820	$ 14	26,047	-	(816)	1,592	(242)	16,128	42,723
Net income										13,529	13,529
Other comprehensive income (loss)											
Minimum pension liability adjustment								(56)			(56)
Foreign currency translation adjustments								(717)			(717)
Unrealized loss on securities								(6)			(6)
Hedging activities								1			1
Comprehensive income											12,751
Cash dividends paid on company common stock										(1,639)	(1,639)
Repurchase of company common stock		32,080,000				(1,924)					(1,924)
Distributed under incentive compensation and other benefit plans	18,131,678		(2,250,727)		707		38				745

Recognition of unearned compensation									75		75
December 31, 2005	1,455,861,340	32,080,000	45,932,093	14	26,754	(1,924)	(778)	814	(167)	28,018	52,731
Net income										15,550	15,550
Other comprehensive income											
Minimum pension liability adjustment								33			33
Foreign currency translation adjustments								1,013			1,013
Hedging activities								4			4
Comprehensive income											16,600
Initial application of SFAS No. 158								(575)			(575)
Cash dividends paid on company common stock										(2,277)	(2,277)
Burlington Resources acquisition	239,733,571	(32,080,000)	890,180	3	14,475	1,924	(53)				16,349
Repurchase of company common stock		15,061,613	(542,000)			(964)	32				(932)
Distributed under incentive compensation and other benefit plans	9,907,698		(1,921,688)		697		33				730
Recognition of unearned compensation									19		19
Other										1	1
December 31, 2006	1,705,502,609	15,061,613	44,358,585	17	41,926	(964)	(766)	1,289	(148)	41,292	82,646

Net income										**11,891**	**11,891**
Other comprehensive income (loss)											
Defined benefit pension plans:											
Net prior service cost								**63**			**63**
Net gain								**213**			**213**
Non-sponsored plans								**(2)**			**(2)**
Foreign currency translation adjustments								**3,075**			**3,075**
Hedging activities								**(4)**			**(4)**
Comprehensive income											**15,236**
Initial application of SFAS No. 158 equity affiliate								**(74)**			**(74)**
Cash dividends paid on company common stock										**(2,661)**	**(2,661)**
Repurchase of company common stock		**89,545,536**	**(177,110)**			**(7,005)**	**11**				**(6,994)**
Distributed under incentive compensation and other benefit plans	**12,946,220**		**(1,856,224)**		**798**		**31**				**829**
Recognition of unearned compensation									**20**		**20**
Other			**86,080**				**(7)**			**(12)**	**(19)**
December 31, 2007	**1,718,448,829**	**104,607,149**	**42,411,331**	**$17**	**42,724**	**(7,969)**	**(731)**	**4,560**	**(128)**	**50,510**	**88,983**

See Notes to Consolidated Financial Statements.

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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. The cost method is used when we do not have the ability to exert significant influence. Undivided interests in oil and gas joint ventures, pipelines, natural gas plants, certain transportation assets and Canadian Syncrude mining operations are consolidated on a proportionate basis. Other securities and investments, excluding marketable securities, are generally carried at cost.

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

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

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

  Prior to April 1, 2006, revenues included the sales portion of transactions commonly called buy/sell contracts. Effective April 1, 2006, we implemented Emerging Issues Task Force (EITF) Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. Issue No. 04-13 requires purchases and sales of inventory with the same counterparty and entered into in contemplation of one another to be combined and reported net (i.e., on the same income statement line). See Note 2 Changes in Accounting Principles, for additional information about our adoption of this Issue.

  Revenues from the production of natural gas and crude oil 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 non-recoverable 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 royalty fees from licensed technology are recorded based either upon volumes produced by the licensee or upon the successful completion of all substantive performance requirements related to the installation of licensed technology.

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

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

- **Inventories** We have several valuation methods for our various types of inventories and consistently use the following methods for each type of inventory. Crude oil, petroleum products, and Canadian Syncrude 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 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/non-recurring 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.

- **Derivative Instruments** All derivative instruments are recorded on the balance sheet at fair value in either prepaid expenses and other current assets, other assets, other accruals, or other liabilities and deferred credits. 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 that are not accounted for as hedges under Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, 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 will be recorded 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.

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

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- **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 the classification of reserves 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 we seek government or co-venturer approval of development plans or seek environmental permitting. Once all required approvals and permits have been obtained, the projects are moved into the development phase and the oil and gas reserves are designated as proved reserves.

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as a dry hole when it judges that the potential field does not warrant further investment in the near term.

See Note 11 Properties, Plants and Equipment, 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.

- **Syncrude Mining Operations** Capitalized costs, including support facilities, include property acquisition costs and other capital costs incurred. Capital costs are depreciated using the unit-of-production method based on the applicable portion of proven reserves associated with each mine location and its facilities.

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

- **Intangible Assets Other Than Goodwill** Intangible assets that have finite useful lives are amortized by the straight-line method over their useful lives. Intangible assets that have indefinite useful lives are not amortized but are tested at least annually for impairment. Each reporting period, we evaluate the remaining useful lives of intangible assets not being amortized to determine whether events and circumstances continue to support indefinite useful lives. Intangible assets 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 commensurate with the risks involved in the asset, or upon estimated replacement cost, if expected future cash flows from the intangible asset are not determinable.

n **Goodwill** Goodwill 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, three reporting units had been determined prior to 2007: Worldwide Exploration and Production, Worldwide Refining and Worldwide Marketing. In 2007, the Refining unit and Marketing unit were combined into one unit, Worldwide Refining and Marketing. Because quoted market prices are not available for the company s reporting units, the fair value of the reporting units is determined based upon consideration of several factors, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the operations and observed market multiples of operating cash flows and net income.

n **Depreciation and Amortization** Depreciation and amortization of properties, plants and equipment on producing oil and gas properties, certain pipeline assets (those which are expected to have a declining utilization pattern), and on Syncrude mining operations 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. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value through additional amortization or depreciation provisions and reported as impairments in the periods in which the determination of the impairment is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets generally on a field-by-field basis for exploration and production assets, at an entire complex level for refining assets or at a site level for retail stores. The fair value of impaired assets is determined based on quoted market prices in active markets, if available, or upon the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group. 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.

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. The price and cost outlook assumptions used in impairment reviews differ from the assumptions used in the Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities. In that disclosure, SFAS No. 69, Disclosures about Oil and Gas Producing Activities, requires inclusion of only proved reserves and the use of prices and costs at the balance sheet date, with no projection for future changes in assumptions.

- **Impairment of Investments in Non-Consolidated Companies** Investments in non-consolidated companies are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred, which is other than a temporary decline in 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 commensurate with the risks of the investment.

- **Maintenance and Repairs** The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred.

- **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 which clearly benefit from the expenditure.

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

- **Asset Retirement Obligations and Environmental Costs** We record the fair value of legal obligations to retire and remove long-lived assets 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 14 Asset Retirement Obligations and Accrued Environmental Costs, for additional information.

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

- **Guarantees** The 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 income statement line item based on the nature of the guarantee. When it becomes probable that we will have to perform on a guarantee, we accrue a separate liability if it is reasonably estimable, based on the facts and circumstances at that time. We reverse the fair value liability only when there is no further exposure under the guarantee.

- **Stock-Based Compensation** Effective January 1, 2003, we voluntarily adopted the fair value accounting method prescribed by SFAS No. 123, Accounting for Stock-Based Compensation. We used the prospective transition method, applying the fair value accounting method and recognizing compensation expense equal to the fair-market value on the grant date for all stock options granted or modified after December 31, 2002.

  Employee stock options granted prior to 2003 were accounted for under Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, and related Interpretations; however, by the end of 2005, all of these awards had vested. Because the exercise price of our employee stock options equaled the market price of the underlying stock on the date of grant, generally no compensation expense was recognized under APB Opinion No. 25. The following table displays 2005 pro forma information as if the provisions of SFAS No. 123 had been applied to all employee stock options granted:

	Millions of Dollars
Net income, as reported	$ 13,529
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	142
Deduct: Total stock-based employee compensation expense determined under fair-value based method for all awards, net of related tax effects	(144)
Pro forma net income	$ 13,527
Earnings per share:	
Basic as reported	$ 9.71
Basic pro forma	9.71
Diluted as reported	9.55
Diluted pro forma	9.55

Generally, our stock-based compensation programs provided 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. We recognized expense for these awards over the period of time during which the employee earned the award, accelerating the recognition of expense only when an employee actually retired (both the actual expense and the pro forma expense shown in the preceding table were calculated in this manner).

Effective January 1, 2006, we adopted SFAS No. 123 (revised 2004), Share-Based Payment (SFAS No. 123(R)), which requires us to recognize stock-based compensation expense for new awards over the shorter of: 1) the service period (i.e., the stated period of time required to earn the award); or 2) the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement. This shortens the period over which we recognize expense for most

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of our stock-based awards granted to our employees who are already age 55 or older, but it has not had a material effect on our consolidated financial statements. For share-based awards granted after our adoption of SFAS No. 123(R), 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 Per Share of Common Stock** Basic income 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 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. Treasury stock and shares held by the grantor trusts are excluded from the daily weighted-average number of common shares outstanding in both calculations.

n **Accounting for Sales of Stock by Subsidiary or Equity Investees** We recognize a gain or loss upon the direct sale of non-preference equity by our subsidiaries or equity investees if the sales price differs from our carrying amount, and provided that the sale of such equity is not part of a broader corporate reorganization.

Note 2 Changes in Accounting Principles

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48). This Interpretation provides guidance on recognition, classification and disclosure concerning uncertain tax liabilities. The evaluation of a tax position requires recognition of a tax benefit if it is more likely than not it will be sustained upon examination. We adopted FIN 48 effective January 1, 2007. The adoption did not have a material impact on our consolidated financial statements. See Note 24 Income Taxes, for additional information about income taxes.

Effective April 1, 2006, we implemented EITF Issue No. 04-13, which requires purchases and sales of inventory with the same counterparty and entered into in contemplation of one another to be combined and reported net (i.e., on the same income statement line). Exceptions to this are exchanges of finished goods for raw materials or work-in-progress within the same line of business, which are only reported net if the transaction lacks economic substance. The implementation of Issue No. 04-13 did not have a material impact on net income.

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The table below shows the actual 2007, sales and other operating revenues, and purchased crude oil, natural gas and products under Issue No. 04-13, and the respective pro forma amounts had this new guidance been effective for all the periods prior to April 1, 2006.

	Millions of Dollars		
	Actual	Pro Forma	
	2007	2006	2005
Sales and other operating revenues	**$ 187,437**	176,993	154,692
Purchased crude oil, natural gas and products	**123,429**	112,242	100,175

For information on our December 31, 2005, adoption of FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143, and related disclosures, see Note 14 Asset Retirement Obligations and Accrued Environmental Costs.

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

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

We adopted the provisions of this Statement effective December 31, 2006, except for the requirement to measure plan assets and benefit obligations as of the date of the employer s fiscal year end, which we will adopt effective December 31, 2008. For information on the impact of the adoption of this new Statement, see Note 23 Employee Benefit Plans.

In June 2006, the FASB ratified EITF Issue No. 06-3, How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That is, Gross versus Net Presentation). Issue No. 06-3 requires disclosure of either the gross or net method of presentation for taxes assessed by a governmental authority resulting from specific revenue-producing transactions between a customer and a seller. For any such taxes reported on a gross basis, the entity must also disclose the amount of the tax reported in revenue in the interim and annual financial statements. We adopted the Issue effective December 31, 2006. See Note 1 Accounting Policies, for additional information.

In December 2004, the FASB issued SFAS No. 123 (revised 2004), Share-Based Payment, (SFAS No. 123(R)), which superseded APB Opinion No. 25, Accounting for Stock Issued to Employees, and replaced SFAS No. 123, Accounting for Stock-Based Compensation, that we adopted effective January 1, 2003. SFAS No. 123(R) prescribes the accounting for a wide range of share-based compensation arrangements, including options, restricted-share plans, performance-based awards, share appreciation rights, and employee share purchase plans, and generally requires the fair value of share-based awards to

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be expensed. Our adoption of the provisions of this Statement on January 1, 2006, using the modified-prospective transition method, did not have a material impact on our financial statements. For more information on our adoption of SFAS No. 123(R) and its effect on net income, see Note 1 Accounting Policies and the Share-Based Compensation Plans section in Note 23 Employee Benefit Plans.

In November 2004, the FASB issued SFAS No. 151, Inventory Costs, an amendment of ARB No. 43, Chapter 4. This Statement clarifies how items, such as abnormal amounts of idle facility expense, freight, handling costs, and wasted material (spoilage) should be recognized as current-period charges. In addition, the Statement requires the allocation of fixed production overhead to the costs of conversion be based on the normal capacity of the production facilities. We adopted this Statement effective January 1, 2006. The adoption did not have a material impact on our financial statements.

Note 3 Common Stock Split

On April 7, 2005, our Board of Directors declared a 2-for-1 common stock split effected in the form of a 100 percent stock dividend, payable June 1, 2005, to stockholders of record as of May 16, 2005. The total number of authorized common shares and associated par value per share were unchanged by this action. Shares and per-share information in this report are on an after-split basis for all periods presented.

Note 4 Discontinued Operations

During 2005, we sold the majority of the remaining assets that had been previously classified as discontinued operations and reclassified the remaining immaterial assets back into continuing operations.

Sales and other operating revenues and income (loss) from discontinued operations for 2005 were as follows:

	Millions of Dollars
Sales and other operating revenues from discontinued operations	$ 356
Discontinued operations before-tax	$ (26)
Income tax benefit	(3)
Discontinued operations	$ (23)

Note 5 Acquisition of Burlington Resources Inc.

On March 31, 2006, we completed the $33.9 billion acquisition of Burlington Resources Inc., an independent exploration and production company that held a substantial position in North American natural gas proved reserves, production and exploratory acreage. We issued approximately 270.4 million shares of our common stock and paid approximately $17.5 billion in cash. We acquired $3.2 billion in cash and assumed $4.3 billion of debt from Burlington Resources in the acquisition, including recognition of an increase of $406 million to record the debt at its fair value. Results of operations attributable to Burlington Resources were included in our consolidated income statement beginning in the second quarter of 2006.

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The primary reasons for the acquisition and the principal factors contributing to a purchase price resulting in the recognition of goodwill were expanded growth opportunities in North American natural gas exploration and development, cost savings from the elimination of duplicate activities, and the sharing of best practices in the operations of both companies.

The $33.9 billion purchase price was based on Burlington Resources shareholders receiving $46.50 in cash and 0.7214 shares of ConocoPhillips common stock for each Burlington Resources share owned. ConocoPhillips issued approximately 270.4 million shares of common stock and approximately 3.6 million vested employee stock options in exchange for 374.8 million shares of Burlington Resources common stock and 2.5 million Burlington Resources vested stock options. The ConocoPhillips common stock was valued at $59.85 per share, which was the weighted-average price of ConocoPhillips common stock for a five-day period beginning two available trading days before the public announcement of the transaction on the evening of December 12, 2005. The Burlington Resources vested stock options, whose fair value was determined using the Black-Scholes-Merton option-pricing model, were exchanged for ConocoPhillips stock options valued at $146 million. Estimated transaction-related costs were $56 million.

Also included in the acquisition was the replacement of 0.9 million non-vested Burlington Resources stock options and 0.4 million shares of non-vested restricted stock with 1.3 million non-vested ConocoPhillips stock options and 0.5 million non-vested ConocoPhillips restricted stock. In addition, 1.2 million Burlington Resources shares of common stock held by a consolidated grantor trust, related to a deferred compensation plan, were converted into 0.9 million ConocoPhillips common shares and were recorded as a reduction of common stockholders equity.

The final allocation of the purchase price to specific assets and liabilities was completed in the first quarter of 2007. It was based on the fair value of Burlington Resources long-lived assets and the conclusion of the fair value determination of all other Burlington Resources assets and liabilities.

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The following table summarizes the final purchase price allocation of the fair value of the assets acquired and liabilities assumed as of March 31, 2006:

	Millions of Dollars
Cash and cash equivalents	$ 3,238
Accounts and notes receivable	1,432
Inventories	229
Prepaid expenses and other current assets	108
Investments and long-term receivables	268
Properties, plants and equipment	28,176
Goodwill	16,787
Intangibles	107
Other assets	46
Total Assets	$ 50,391
Accounts payable	$ 1,487
Notes payable and long-term debt due within one year	1,009
Accrued income and other taxes	697
Employee benefit obligations current	248
Other accruals	254
Long-term debt	3,330
Asset retirement obligations	730
Accrued environmental costs	174
Deferred income taxes	7,849
Employee benefit obligations	347
Other liabilities and deferred credits	397
Common stockholders equity	33,869
Total Liabilities and Equity	$ 50,391

All of the goodwill was assigned to the Worldwide Exploration and Production reporting unit. Of the $16,787 million of goodwill, $7,953 million relates to net deferred tax liabilities arising from differences between the allocated financial bases and deductible tax bases of the acquired assets. None of the goodwill is deductible for tax purposes.

The following table presents pro forma information for 2006 and 2005, as if the acquisition had occurred at the beginning of each year presented.

	Millions of Dollars	
	2006	2005
Pro Forma		
Sales and other operating revenues*	$ 185,555	186,227
Income from continuing operations	15,945	14,780
Net income	15,945	14,669
Income from continuing operations per share of common stock		
Basic	9.65	8.88
Diluted	9.51	8.75
Net income per share of common stock		
Basic	9.65	8.82
Diluted	9.51	8.68

**See Note 2 Changes in Accounting Principles, for information affecting the comparability of 2006 with 2005 due to the adoption of EITF Issue No. 04-13.*

The pro forma information is not intended to reflect the actual results that would have occurred if the companies had been combined during the periods presented, nor is it intended to be indicative of the results of operations that may be achieved by ConocoPhillips in the future.

Note 6 Restructuring

As a result of the acquisition of Burlington Resources, we implemented a restructuring program in March 2006 to capture the synergies of combining the two companies. Under this program, we recorded accruals totaling $230 million in 2006 for employee severance payments, site closings, incremental pension benefit costs associated with the work force reductions, and employee relocations. Approximately 600 positions were identified for elimination, most of which were in the United States.

Of the total accrual, $224 million was reflected in the Burlington Resources purchase price allocation as an assumed liability, and $6 million ($4 million after-tax) related to ConocoPhillips was reflected in selling, general and administrative expenses in 2006. Included in the total accruals of $230 million was $12 million related to pension benefits to be paid in conjunction with other retirement benefits over a number of future years. The following table summarizes activity related to the non-pension accrual.

	Millions of Dollars
Balance at January 1, 2006	$ -
Accruals	218
Benefit payments	(98)
Balance at December 31, 2006	120
Accruals	**13**
Benefit payments	**(68)**
Balance at December 31, 2007	**$ 65***

**Includes current liabilities of $40 million. All work force reductions are expected to be completed by March 2008. Some site closings and continuation of employee benefits are expected to extend beyond one year from December 31, 2007.*

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Note 7 Variable Interest Entities (VIEs)

In June 2006, ConocoPhillips acquired a 24 percent interest in West2East Pipeline LLC (West2East), a company holding a 100 percent interest in Rockies Express Pipeline LLC (Rockies Express). Rockies Express plans to construct a natural gas pipeline from Colorado to Ohio. West2East is a VIE because a third party other than ConocoPhillips and our partners holds a significant voting interest in the company until project completion. We currently participate in the management committee of West2East as a non-voting member. We are not the primary beneficiary of West2East, and we use the equity method of accounting for our investment. We issued a guarantee for 24 percent of the $2 billion in credit facilities of Rockies Express. In addition, we have a guarantee for 24 percent of $600 million of Floating Rate Notes due 2009 issued by Rockies Express in September 2007. At December 31, 2007, the book value of our investment in West2East was $101 million. See Note 17 Guarantees, for additional information.

In June 2005, ConocoPhillips and OAO LUKOIL (LUKOIL) created 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 our related party, LUKOIL, have disproportionate interests. We have a 30 percent ownership interest with a 50 percent governance interest in the joint venture. We are not the primary beneficiary of the VIE and we use the equity method of accounting for this investment. At December 31, 2007, the book value of our investment in the venture was $1,662 million.

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. LUKOIL intends to complete an expansion of the terminal s oil-throughput capacity from 30,000 barrels per day to 240,000 barrels per day, with ConocoPhillips participating in the financing of the expansion. The terminal entity, Varandey Terminal Company, is a VIE because we and our related party, LUKOIL, have disproportionate interests. We have an obligation to fund, through loans, 30 percent of the terminal s costs, but we will have no governance or ownership interest in the terminal. We are not the primary beneficiary and account for our loan to Varandey Terminal Company as a financial asset. We estimate our total loan obligation for the terminal expansion to be approximately $416 million at current exchange rates, excluding interest to be accrued during construction. This amount will be adjusted as the project s cost estimate and schedule are updated and the ruble exchange rate fluctuates. Through December 31, 2007, we had provided $331 million in loan financing, and an additional $32 million of accrued interest.

In 2004, we finalized a transaction 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 obtained a 50 percent interest in Freeport LNG GP, Inc., which serves as the general partner managing the venture. We entered into a credit agreement with Freeport LNG, whereby we will provide loan financing of approximately $631 million, excluding accrued interest for the construction of the terminal. Through December 31, 2007, we had provided $594 million in financing, and an additional $87 million of accrued interest. Freeport LNG is a VIE, and we are not the primary beneficiary. We account for our loan to Freeport LNG as a financial asset.

In 2003, we entered into two 20-year agreements establishing separate guarantee facilities of $50 million each for two LNG ships then under construction. Subject to the terms of the facilities, we will be required to make payments should the charter revenue generated by the respective ships fall below a certain specified minimum threshold, and we will receive payments to the extent that such revenues exceed those thresholds. To the extent we receive any such payments, our actual gross payments over the 20 years could exceed $100 million. In September 2003, the first ship was delivered to its owner and in July 2005, the second ship was delivered to its owner. Both agreements represent a VIE, but we are not the primary beneficiary and, therefore, we do not consolidate these entities. The amount drawn under the guarantee facilities at December 31, 2007, was approximately $5 million for both ships. We currently account for these agreements as guarantees and contingent liabilities. See Note 17 Guarantees, for additional information.

In 1997, Phillips 66 Capital II (Trust II) was created for the sole purpose of issuing mandatorily redeemable preferred securities to third-party investors and investing the proceeds thereof in an approximate amount of subordinated debt securities of ConocoPhillips. At December 31, 2006, we reported debt of $361 million of 8% Junior Subordinated Deferrable Interest Debentures due 2037. Trust II is a VIE, but we do not consolidate it in our financial statements because we are not the primary beneficiary. Effective January 15, 2007, we redeemed the 8% Junior Subordinated Deferrable Interest Debentures due 2037 at a premium of $14 million, plus accrued interest. See Note 15 Debt, for additional information about Trust II.

In December 2006, we terminated the lease of certain refining assets which we consolidated due to our designation as the primary beneficiary of the lease entity. As part of the termination, we exercised a purchase option of the assets totaling $111 million and retired the related debt obligations of $104 million 5.847% Notes due 2006. An associated interest rate swap was also liquidated.

Ashford Energy Capital S.A. (Ashford) is consolidated in our financial statements because we are the primary beneficiary. In December 2001, in order to raise funds for general corporate purposes, ConocoPhillips and Cold Spring Finance S.a.r.l. (Cold Spring) formed Ashford through the contribution of a $1 billion ConocoPhillips subsidiary promissory note and $500 million cash. Through its initial $500 million investment, Cold Spring is entitled to a cumulative annual preferred return, based on three-month LIBOR rates, plus 1.32 percent. The preferred return at December 31, 2007, was 6.55 percent. In 2008, and each 10-year anniversary thereafter, Cold Spring may elect to remarket their investment in Ashford, and if unsuccessful, could require ConocoPhillips to provide a letter of credit in support of Cold Spring s investment, or in the event that such letter of credit is not provided, then cause the redemption of their investment in Ashford. Should ConocoPhillips credit rating fall below investment grade, Ashford would require a letter of credit to support $475 million of the term loans, as of December 31, 2007, made by Ashford to other ConocoPhillips subsidiaries. If the letter of credit is not obtained within 60 days, Cold Spring could cause Ashford to sell the ConocoPhillips subsidiary notes. At December 31, 2007, Ashford held $2.0 billion of ConocoPhillips subsidiary notes and $29 million in investments unrelated to ConocoPhillips. We report Cold Spring s investment as a minority interest because it is not mandatorily redeemable and the entity does not have a specified liquidation date. Other than the obligation to make payment on the subsidiary notes described above, Cold Spring does not have recourse to our general credit.

Note 8 Inventories

Inventories at December 31 were:

	Millions of Dollars	
	2007	2006
Crude oil and petroleum products	**$ 3,373**	4,351
Materials, supplies and other	**850**	802
	$ 4,223	5,153

Inventories valued on a LIFO basis totaled $2,974 million and $4,043 million at December 31, 2007 and 2006, respectively. The remainder of our inventories is valued under various methods, including FIFO and weighted average. The excess of current replacement cost over LIFO cost of inventories amounted to $6,668 million and $4,178 million at December 31, 2007 and 2006, respectively.

During 2007, certain inventory quantity reductions caused a liquidation of LIFO inventory values. This liquidation increased net income $280 million, of which $260 million was attributable to our R&M segment. In 2006, a liquidation of LIFO inventory values increased net income $39 million, of which $32 million was attributable to our R&M segment. Comparable amounts in 2005 increased net income $16 million, of which $15 million was attributable to our R&M segment.

Note 9 Assets Held for Sale

In 2006, we announced the commencement of certain asset rationalization efforts. During the third and fourth quarters of 2006, certain assets included in these efforts met the held-for-sale criteria of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. Accordingly, in the third and fourth quarters of 2006, on those assets required, we reduced the carrying value of the assets held for sale to estimated fair value less costs to sell, resulting in an impairment of properties, plants and equipment, goodwill and intangibles totaling $496 million before-tax ($464 million after-tax). Further, we ceased depreciation, depletion and amortization of the properties, plants and equipment associated with these assets in the month they were classified as held for sale.

At December 31, 2006, we classified $3,051 million of non-current assets as Prepaid expenses and other current assets on our consolidated balance sheet and we classified $604 million of non-current liabilities as current liabilities, consisting of $201 million in Accrued income and other taxes and $403 million in Other accruals.

During 2007, a significant portion of these held-for-sale assets were sold, additional assets met the held-for-sale criteria, and other assets no longer met the held-for-sale criteria. As a result, at December 31, 2007, we classified $1,092 million of non-current assets as Prepaid expenses and other current assets on our consolidated balance sheet and we classified $159 million of non-current liabilities as current liabilities, consisting of $133 million in Accrued income and other taxes and $26 million in Other accruals. We expect the disposal of these assets to be completed by the end of 2008.

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The major classes of non-current assets and non-current liabilities held for sale at December 31 classified to current were:

	Millions of Dollars	
	2007	2006
Assets		
Investments and long-term receivables	$ **48**	170
Net properties, plants and equipment	**946**	2,422
Goodwill	**89**	340
Intangibles	**2**	13
Other assets	**7**	106
Total assets reclassified	$ **1,092**	3,051
Exploration and Production	$ **189**	1,465
Refining and Marketing	**903**	1,586
	$ **1,092**	3,051
Liabilities		
Asset retirement obligations and accrued environmental costs	$ **23**	386
Deferred income taxes	**133**	201
Other liabilities and deferred credits	**3**	17
Total liabilities reclassified	$ **159**	604
Exploration and Production	$ **35**	392
Refining and Marketing	**124**	212
	$ **159**	604

Note 10 Investments, Loans and Long-Term Receivables

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

	Millions of Dollars	
	2007	2006
Equity investments	$ **30,408**	18,544
Loans and advances related parties	**1,871**	1,118
Long-term receivables	**495**	442
Other investments	**554**	609
	$ **33,328**	20,713

Equity Investments

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

FCCL Oil Sands Partnership (FCCL) 50 percent owned business venture with EnCana Corporation produces heavy-oil in the Athabasca oil sands in northeast Alberta, as well as transports and sells the bitumen blend.

WRB Refining LLC (WRB) 50 percent owned business venture with EnCana Corporation processes crude oil at the Wood River and Borger refineries, as well as purchases and transports all feedstocks for the refineries and sells the refined products.

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OAO LUKOIL (LUKOIL) 20 percent ownership interest. LUKOIL explores for and produces crude oil, natural gas and natural gas liquids; refines, markets and transports crude oil and petroleum products; and is headquartered in Russia.

OOO Naryanmarneftegaz (NMNG) 30 percent ownership interest and a 50 percent governance interest a joint venture with LUKOIL to explore for and develop oil and gas resources in the northern part of Russia s Timan-Pechora province.

DCP Midstream, LLC (DCP Midstream) 50 percent owned joint venture with Spectra Energy owns and operates gas plants, gathering systems, storage facilities and fractionation plants. Effective January 2, 2007, Duke Energy Field Services, LLC (DEFS) formally changed its name to DCP Midstream.

Chevron Phillips Chemical Co. LLC (CPChem) 50 percent owned joint venture with Chevron Corporation manufactures and markets petrochemicals and plastics.

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

	Millions of Dollars		
	2007	2006	2005
Revenues	**$ 143,686**	113,607	96,367
Income before income taxes	**19,807**	16,257	15,059
Net income	**15,229**	12,447	11,743
Current assets	**29,451**	24,820	23,652
Noncurrent assets	**90,939**	59,803	48,181
Current liabilities	**16,882**	15,884	14,727
Noncurrent liabilities	**26,656**	20,603	15,833

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, 2007, retained earnings included $4,053 million related to the undistributed earnings of affiliated companies, and distributions received from affiliates were $3,326 million, $3,294 million and $1,807 million in 2007, 2006 and 2005, respectively.

Business Ventures with EnCana

In October 2006, we announced a business venture with EnCana Corporation (EnCana) to create an integrated North American heavy-oil business. The transaction closed on January 3, 2007, and consists of two 50/50 business ventures, a Canadian upstream general partnership, FCCL Oil Sands Partnership (FCCL), and a U.S. downstream limited liability company, WRB Refining LLC (WRB). 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.

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 northeast Alberta. A subsidiary of EnCana 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 beginning in 2007. For additional information on this obligation, see Note 16 Joint Venture Acquisition Obligation.

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 of $5.0 billion was created due to the fair value of the contributed assets recorded by WRB exceeding their historic book value. The difference is amortized and recognized as a benefit evenly over a period of 25 years, which is the estimated remaining useful life of the refineries at the closing date. The basis difference at December 31, 2007, was approximately $4.8 billion. We are the operator and managing partner of WRB. EnCana is obligated to contribute $7.5 billion, plus accrued interest, to WRB over a 10-year period beginning in 2007. For the Wood River refinery, operating results are shared 50/50 starting upon formation. For the Borger refinery, we were entitled to 85 percent of the operating results in 2007, with our share decreasing to 65 percent in 2008, and 50 percent in all years thereafter.

LUKOIL

LUKOIL is an integrated energy company headquartered in Russia, with operations worldwide. In 2004, we made a joint announcement with LUKOIL of an agreement to form a broad-based strategic alliance, whereby we would become a strategic equity investor in LUKOIL.

During the January 24, 2005, extraordinary general meeting of LUKOIL shareholders, all charter amendments reflected in the Shareholder Agreement were passed and ConocoPhillips nominee was elected to LUKOIL s Board. The Shareholder Agreement limits our ownership interest in LUKOIL to 20 percent of the shares authorized and issued and limits our ability to sell our LUKOIL shares for a period of four years from September 29, 2004, except in certain circumstances. Our ownership interest in LUKOIL was 16.1 percent at December 31, 2005, and 20 percent at both December 31, 2006 and 2007, based on 851 million shares authorized and issued.

For financial reporting under U.S. generally accepted accounting principles, treasury shares held by LUKOIL are not considered outstanding for determining our equity-method ownership interest in LUKOIL. Our ownership interest, based on estimated shares outstanding, was 20.6 percent at December 31, 2007 and 2006.

Because LUKOIL s accounting cycle close and preparation of U.S. generally accepted accounting principles (GAAP) financial statements occur subsequent to our reporting deadline, our equity earnings and statistics for our LUKOIL investment are estimated, based on current market indicators, publicly available LUKOIL operating results, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. This estimate-to-actual adjustment will be a recurring component of future period results. Any difference between our estimate of fourth-quarter 2007 and the actual LUKOIL U.S. GAAP net income will be reported in our 2008 equity earnings. At December 31, 2007, the book value of our ordinary share investment in LUKOIL was $11,162 million. Our 20 percent share of the net assets of LUKOIL was estimated to be $8,627 million. This basis difference of $2,535 million is primarily being amortized on a unit-of-production basis. Included in net income for 2007, 2006 and 2005 was after-tax expense of $76 million, $41 million and $43 million, respectively, representing the amortization of this basis difference.

On December 31, 2007, the closing price of LUKOIL shares on the London Stock Exchange was $86.50 per share, making the aggregate total market value of our LUKOIL investment $14,715 million.

OOO Naryanmarneftegaz

OOO Naryanmarneftegaz (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 ownership interest with a 50 percent governance interest. NMNG is working to develop the Yuzhno Khylchuyu (YK) field. 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.

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We use the equity method of accounting for this joint venture and the book value of our investment in the venture at December 31, 2007, was $1,662 million.

DCP Midstream

DCP Midstream owns and operates gas plants, gathering systems, storage facilities and fractionation plants. In July 2005, ConocoPhillips and Duke Energy Corporation (Duke) restructured their respective ownership levels in DCP Midstream, which resulted in DCP Midstream becoming a jointly controlled venture, owned 50 percent by each company. This restructuring increased our ownership in DCP Midstream to 50 percent from 30.3 percent through a series of direct and indirect transfers of certain Canadian Midstream assets from DCP Midstream to Duke, a disproportionate cash distribution from DCP Midstream to Duke from the sale of DCP Midstream s interest in TEPPCO Partners, L.P., and a combined payment by ConocoPhillips to Duke and DCP Midstream of approximately $840 million. Our interest in the Empress plant in Canada was not included in the initial transaction as originally anticipated due to weather-related damage to the facility. Subsequently, the Empress plant was sold to Duke on August 1, 2005, for approximately $230 million. In the first quarter of 2005, as a part of equity earnings, we recorded our $306 million (after-tax) equity share of the gain from DCP Midstream s sale of its interest in TEPPCO.

At December 31, 2007, the book value of our common investment in DCP Midstream was $998 million. Our 50 percent share of the net assets of DCP Midstream was $982 million. This difference of $16 million is being amortized on a straight-line basis through 2014 consistent with the remaining estimated useful lives of DCP Midstream s properties, plants and equipment.

DCP Midstream markets a portion of its natural gas liquids to us and CPChem under a supply agreement that continues until December 31, 2014. This purchase commitment is on an if-produced, will-purchase basis so it has no fixed production schedule, but has been, and is expected to be, a relatively stable purchase pattern over the term of the contract. 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, 2007, the book value of our investment in CPChem was $2,203 million. Our 50 percent share of the total net assets of CPChem was $2,080 million. This basis difference of $123 million is being amortized through 2020, consistent with the remaining estimated useful lives of CPChem properties, plants and equipment.

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.

Investments in Venezuela

See the Expropriated Assets section of Note 13 Impairments, for information on the complete impairment of our investments in the Hamaca and Petrozuata projects.

Loans to Related Parties

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

Significant loans to affiliated companies include the following:

We entered into a credit agreement with Freeport LNG, whereby we will provide loan financing of approximately $631 million, excluding accrued interest, for the construction of an LNG facility. Through December 31, 2007, we have provided $594 million in loan financing, and an additional $87 million of accrued interest. See Note 7 Variable Interest Entities (VIEs), for additional information.

We have an obligation to provide loan financing to Varandey Terminal Company for 30 percent of the costs of the terminal expansion. We estimate our total loan obligation for the terminal expansion to be approximately $416 million at current exchange rates, excluding interest to be accrued during construction. This amount will be adjusted as the project s cost estimate and schedule are updated and the ruble exchange rate fluctuates. Through December 31, 2007, we had provided $331 million in loan financing, and an additional $32 million of accrued interest. See Note 7 Variable Interest Entities (VIEs), for additional information.

Qatargas 3 is an integrated project to produce and liquefy natural gas from Qatar s North field. We own a 30 percent interest in the project. The other participants in the project are affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent). Our interest is held through a jointly owned company, Qatar Liquefied Gas Company Limited (3), for which we use the equity method of accounting. Qatargas 3 secured project financing of $4 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. Prior to project completion certification, all loans, including the ConocoPhillips loan facilities, are guaranteed by the participants based on their respective ownership interests. Accordingly, our maximum exposure to this financing structure is $1.2 billion, excluding accrued interest. Upon completion certification, which is expected in 2010, all project loan facilities, including the ConocoPhillips loan facilities, will become non-recourse to the project participants. At December 31, 2007, Qatargas 3 had $2.4 billion outstanding under all the loan facilities, of which ConocoPhillips provided $690 million, and an additional $43 million of accrued interest.

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Note 11 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					
	2007			2006		
	Gross PP&E	Accum. DD&A	Net PP&E	Gross PP&E	Accum. DD&A	Net PP&E
E&P	**$ 102,550**	**30,701**	**71,849**	88,592	21,102	67,490
Midstream	**267**	**103**	**164**	330	157	173
R&M	**19,926**	**4,733**	**15,193**	22,115	5,199	16,916
LUKOIL Investment	**-**	**-**	**-**	-	-	-
Chemicals	**-**	**-**	**-**	-	-	-
Emerging Businesses	**1,204**	**138**	**1,066**	1,006	98	908
Corporate and Other	**1,414**	**683**	**731**	1,229	515	714
	$ 125,361	**36,358**	**89,003**	113,272	27,071	86,201

Suspended Wells

In April 2005, the FASB issued FSP FAS 19-1, Accounting for Suspended Well Costs (FSP FAS 19-1). This FSP was issued to address whether there were circumstances that would permit the continued capitalization of exploratory well costs beyond one year, other than when further exploratory drilling is planned and major capital expenditures would be required to develop the project. We adopted FSP FAS 19-1 effective January 1, 2005. There was no impact on our consolidated financial statements from the adoption.

The following table reflects the net changes in suspended exploratory well costs during 2007, 2006 and 2005:

	Millions of Dollars		
	2007	2006	2005
Beginning balance at January 1	**$ 537**	339	347
Additions pending the determination of proved reserves	**157**	225	183
Reclassifications to proved properties	**(58)**	(8)	(81)
Sales of suspended well investment	**(22)**	-	-
Charged to dry hole expense	**(25)**	(19)	(110)
Ending balance at December 31	**$ 589***	537*	339

**Includes $7 million and $29 million related to assets held for sale in 2007 and 2006, respectively. See Note 9 Assets Held for Sale, for additional information.*

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The following table provides an aging of suspended well balances at December 31, 2007, 2006 and 2005:

	Millions of Dollars		
	2007	2006	2005
Exploratory well costs capitalized for a period of one year or less	**$ 153**	225	183
Exploratory well costs capitalized for a period greater than one year	**436**	312	156
Ending balance	**$ 589**	537	339
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	**35**	22	15

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, 2007:

	Millions of Dollars						
		Suspended Since					
Project	Total	2006	2005	2004	2003	2002	2001
Aktote Kazakhstan *(2)*	$ 19	-	-	7	12	-	-
Alpine satellite Alaska *(2)*	23	-	-	-	-	23	-
Caldita Australia *(1)*	78	45	33	-	-	-	-
Clair U.K. *(1)*	17	17	-	-	-	-	-
Enochdhu/Finlaggen U.K. *(1)*	11	11	-	-	-	-	-
Humphrey U.K. *(2)*	12	12	-	-	-	-	-
Jasmine U.K. *(1)*	28	28	-	-	-	-	-
K4 U.K. *(2)*	12	12	-	-	-	-	-
Kairan Kazakhstan *(2)*	13	-	-	13	-	-	-
Kashagan Kazakhstan *(1)*	18	-	-	-	9	-	9
Malikai Malaysia *(2)*	50	17	22	11	-	-	-
Plataforma Deltana Venezuela *(2)*	21	-	6	15	-	-	-
Su Tu Trang Vietnam *(2)*	32	16	8	-	8	-	-
Uge Nigeria *(1)*	14	-	14	-	-	-	-
West Sak Alaska *(2)*	10	6	3	1	-	-	-
Twenty projects of less than $10 million each *(1)(2)*	78	48	20	3	3	4	-
Total of 35 projects	$ 436	212	106	50	32	27	9

(1) Additional appraisal wells planned.

(2) Appraisal drilling complete; costs being incurred

to assess development.

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Note 12 Goodwill and Intangibles

Changes in the carrying amount of goodwill are as follows:

		Millions of Dollars		
		E&P	R&M	Total
Balance at December 31, 2005	$	11,423	3,900	15,323
Acquired (Burlington Resources)		16,615	-	16,615
Acquired (Wilhelmshaven)		-	229	229
Goodwill allocated to assets held for sale or sold		(216)	(354)	(570)
Tax and other adjustments		(110)	1	(109)
Balance at December 31, 2006		27,712	3,776	31,488
Goodwill allocated to expropriated assets		**(1,925)**	**-**	**(1,925)**
Acquired (Burlington Resources)		**172**	**-**	**172**
Goodwill allocated to assets held for sale or sold		**(191)**	**(3)**	**(194)**
Tax and other adjustments		**(199)**	**(6)**	**(205)**
Balance at December 31, 2007	**$**	**25,569**	**3,767**	**29,336**

In the second quarter of 2007, we recorded a non-cash impairment related to the expropriation of our oil interests in Venezuela. The impairment included $1,925 million of goodwill allocated to the expropriation event. For additional information, see the Expropriated Assets section of Note 13 Impairments.

On March 31, 2006, we acquired Burlington Resources Inc., an independent exploration and production company. As a result of this acquisition, we recorded goodwill of $16,787 million, all of which was assigned to our Worldwide E&P reporting unit. See Note 5 Acquisition of Burlington Resources Inc., for additional information.

On February 28, 2006, we acquired the Wilhelmshaven refinery, located in Wilhelmshaven, Germany. The purchase included the refinery, a marine terminal, rail and truck loading facilities and a tank farm, as well as another entity that provides commercial and administrative support to the refinery. As a result of this acquisition, we recorded goodwill of $229 million, all of which was assigned to our Worldwide R&M reporting unit. The allocation of the purchase price to specific assets and liabilities was based on an estimate of the fair values of the fixed assets and various other assets and liabilities acquired. This goodwill is not deductible for tax purposes.

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Information on the carrying value of intangible assets follows:

	Millions of Dollars		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized Intangible Assets			
Balance at December 31, 2007			
Technology related	**$ 145**	**(60)**	**85**
Refinery air permits	**14**	**(8)**	**6**
Contract based	**124**	**(62)**	**62**
Other	**37**	**(25)**	**12**
	$ 320	**(155)**	**165**
Balance at December 31, 2006			
Technology related	$ 144	(51)	93
Refinery air permits	32	(12)	20
Contract based	139	(44)	95
Other	31	(24)	7
	$ 346	(131)	215
Indefinite-Lived Intangible Assets			
Balance at December 31, 2007			
Trade names and trademarks	**$ 494**		
Refinery air and operating permits	**237**		
	$ 731		
Balance at December 31, 2006			
Trade names and trademarks	$ 494		
Refinery air and operating permits	242		
	$ 736		

In addition to the above amounts, we had $2 million of intangibles classified as held for sale at December 31, 2007, and $13 million at December 31, 2006. See Note 9 Assets Held for Sale, for additional information.

During 2007, we contributed $11 million of amortized intangible assets and $5 million of indefinite-lived intangible assets to the downstream business venture with EnCana.

Amortization expense related to the intangible assets above for the years ended December 31, 2007 and 2006, was $54 million and $56 million, respectively. The estimated amortization expense for 2008 is approximately $45 million. It is expected to be approximately $20 million per year for 2009 through 2012.

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Note 13 Impairments

Expropriated Assets

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

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

The impairment included equity-method investments and properties, plants and equipment. Also, this expropriation of our oil interests is viewed as a partial disposition of our Worldwide Exploration and Production reporting unit and, under the guidance in SFAS No. 142, Goodwill and Other Intangible Assets, required an allocation of goodwill to the expropriation event. The amount of goodwill impaired as a result of this allocation was $1,925 million.

Negotiations continue between ConocoPhillips and Venezuelan authorities concerning appropriate compensation for the expropriation of the company s interests. We continue to preserve all our rights with respect to this situation, including our rights under the contracts we signed and under international and Venezuelan law. We continue to evaluate our options in realizing adequate compensation for the value of our oil investments and operations in Venezuela and filed a request for international arbitration on November 2, 2007, with the International Centre for Settlement of Investment Disputes (ICSID), an arm of the World Bank. The request was registered by ICSID on December 13, 2007.

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

At December 31, 2006, we had 1,088 million barrels of oil equivalent of proved reserves related to Petrozuata and Hamaca, and 17 million barrels of oil equivalent of proved reserves related to Corocoro. The loss of proved reserves related to these projects has been reflected as a sale in our 2007 reserves disclosures.

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Other Impairments

During 2007, 2006 and 2005, we recognized the following before-tax impairment charges, excluding the impairment of expropriated assets:

	Millions of Dollars		
	2007	2006	2005
E&P			
United States	**$ 73**	55	2
International	**398**	160	2
Midstream	**-**	-	30
R&M			
Goodwill and intangible assets	**-**	300	-
Other	**91**	168	8
Increase in fair value of previously impaired assets	**(128)**	-	-
Corporate	**8**	-	-
	$ 442	683	42

During 2007, we recorded property impairments of $257 million associated with planned asset dispositions, comprised of $187 million of impairments in our E&P segment and $70 million in our R&M segment. In addition to impairments resulting from planned asset dispositions, the E&P segment recorded property impairments in 2007 resulting from:

Increased asset retirement obligations for properties at the end of their economic life for certain fields primarily located in the North Sea, totaling $175 million.

Downward reserve revisions and higher projected operating costs for fields in the United States, Canada and the United Kingdom, totaling $80 million.

An abandoned project in Alaska resulting from increased taxes, totaling $28 million.

In addition to impairments resulting from planned asset dispositions, the R&M segment recorded property impairments in 2007 of $21 million associated with various terminals and pipelines, primarily in the United States.

In addition and in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, we reported a $128 million benefit in 2007 for the subsequent increase in the fair value of certain assets impaired in the prior year, primarily to reflect finalized sales agreements. This gain was included in the Impairments line of the consolidated income statement.

During 2006, we recorded impairments of $496 million associated with planned asset dispositions in our E&P and R&M segments, comprised of properties, plants and equipment ($196 million), trademark intangibles ($70 million), and goodwill ($230 million). In the fourth quarter of 2006, we recorded an impairment of $131 million associated with assets in the Canadian Rockies Foothills area, as a result of declining well performance and drilling results. We recorded a property impairment of $40 million in 2006 as a result of our decision to withdraw an application for a license under the federal Deepwater Port Act, associated with a proposed LNG regasification terminal located offshore Alabama.

In 2005, the E&P segment s impairments were the result of the write-down to market value of properties planned for disposition and properties failing to meet recoverability tests. The Midstream segment recognized property impairments related to planned asset dispositions. Other impairments in R&M primarily were related to assets planned for disposition.

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Note 14 Asset Retirement Obligations and Accrued Environmental Costs

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

	Millions of Dollars	
	2007	2006
Asset retirement obligations	**$ 6,613**	5,402
Accrued environmental costs	**1,089**	1,062
Total asset retirement obligations and accrued environmental costs	**7,702**	6,464
Asset retirement obligations and accrued environmental costs due within one year*	**(441)**	(845)
Long-term asset retirement obligations and accrued environmental costs	**$ 7,261**	5,619

**Classified as a current liability on the balance sheet, under the caption Other accruals. Includes $23 million and $386 million related to assets held for sale in 2007 and 2006, respectively. See Note 9 Assets Held for Sale, for additional information.*

Asset Retirement Obligations

SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation when it is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related properties, plants and equipment. Over time, the liability increases for the change in its present value, while the capitalized cost depreciates over the useful life of the related asset.

In March 2005, the FASB issued FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143 (FIN 47). This Interpretation clarifies that an entity is required to recognize a liability for a legal obligation to perform asset retirement activities when the retirement is conditional on a future event and if the liability s fair value can be reasonably estimated. We implemented FIN 47 effective December 31, 2005. Accordingly, there was no impact on income from continuing operations in 2005. Application of FIN 47 increased net properties, plants and equipment by $269 million, and increased asset retirement obligation liabilities by $417 million. The cumulative effect of this accounting change decreased 2005 net income by $88 million (after reduction of income taxes of $60 million).

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.

SFAS No. 143 calls for measurements of asset retirement obligations to include, as a component of expected costs, an estimate of the price that a third party would demand, and could expect to receive, for bearing the uncertainties and unforeseeable circumstances inherent in the obligations, sometimes referred to as a market-risk premium. To date, the oil and gas industry has no examples of credit-worthy third parties who are willing to assume this type of risk, for a determinable price, on major oil and gas production facilities and pipelines. Therefore, because determining such a market-risk premium would be an arbitrary process, we excluded it from our SFAS No. 143 and FIN 47 estimates.

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During 2007 and 2006, our overall asset retirement obligation changed as follows:

	Millions of Dollars	
	2007	2006
Balance at January 1	**$ 5,402**	3,901
Accretion of discount	**310**	248
New obligations	**76**	154
Burlington Resources acquisition	**-**	732
Changes in estimates of existing obligations	**843**	299
Spending on existing obligations	**(146)**	(130)
Property dispositions	**(259)***	(20)
Foreign currency translation	**395**	218
Expropriation of Venezuela assets	**(8)**	-
Balance at December 31	**$ 6,613**	5,402

**Includes $45 million associated with assets contributed to an equity affiliate.*

The following table presents the estimated 2005 pro forma effects of the retroactive application of the adoption of FIN 47 as if the Interpretation had been adopted on the date the obligations arose:

	Millions of Dollars Except per Share Amounts
Pro forma net income*	$ 13,600
Pro forma earnings per share	
Basic	9.76
Diluted	9.60

**Net income of $13,529 million for 2005 has been adjusted to remove the $88 million cumulative effect of the change in accounting principle attributable to FIN 47.*

Accrued Environmental Costs

Total environmental accruals at December 31, 2007 and 2006, were $1,089 million and $1,062 million, respectively. The 2007 increase in total accrued environmental costs is due to new accruals and accretion, partially offset by payments on accrued environmental costs.

We had accrued environmental costs of $740 million and $669 million at December 31, 2007 and 2006, 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 $255 million and $283 million of environmental costs associated with non-operating sites at December 31, 2007 and 2006, respectively. In addition, $94 million and $110 million were included at December 31, 2007 and 2006, 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 will be paid over periods extending up to 30 years.

Because a large portion of the accrued environmental costs were acquired in various business combinations, they are discounted obligations. Expected expenditures for acquired environmental obligations are discounted using a weighted-average 5 percent discount factor, resulting in an accrued

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balance for acquired environmental liabilities of $836 million at December 31, 2007. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $122 million in 2008, $136 million in 2009, $90 million in 2010, $46 million in 2011, $41 million in 2012, and $516 million for all future years after 2012.

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Note 15 Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2007	2006
9.875% Debentures due 2010	$ **150**	150
9.375% Notes due 2011	**328**	328
9.125% Debentures due 2021	**150**	150
8.75% Notes due 2010	**1,264**	1,264
8.20% Debentures due 2025	**150**	150
8.125% Notes due 2030	**600**	600
8% Junior Subordinated Deferrable Interest Debentures due 2037	**-**	361
7.9% Debentures due 2047	**100**	100
7.8% Debentures due 2027	**300**	300
7.68% Notes due 2012	**37**	43
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 2007	**-**	153
7.25% Notes due 2031	**500**	500
7.20% Notes due 2031	**575**	575
7.125% Debentures due 2028	**300**	300
7% Debentures due 2029	**200**	200
6.95% Notes due 2029	**1,549**	1,549
6.875% Debentures due 2026	**67**	67
6.68% Notes due 2011	**400**	400
6.65% Debentures due 2018	**297**	297
6.50% Notes due 2011	**500**	500
6.40% Notes due 2011	**178**	178
6.375% Notes due 2009	**284**	284
6.35% Notes due 2011	**1,750**	1,750
5.951% Notes due 2037	**645**	-
5.95% Notes due 2036	**500**	500
5.90% Notes due 2032	**505**	505
5.625% Notes due 2016	**1,250**	1,250
5.50% Notes due 2013	**750**	750
5.30% Notes due 2012	**350**	350
4.75% Notes due 2012	**897**	897
Commercial paper at 4.05% - 5.36% at year-end 2007 and 5.27% - 5.47% at year-end 2006	**725**	2,931
Floating Rate Five-Year Term Note due 2011 at 5.0625% at year-end 2007 and 5.575% at year-end 2006	**3,000**	5,000
Floating Rate Notes due 2009 at 5.34% at year-end 2007 and 5.47% at year-end 2006	**950**	1,250
Floating Rate Notes due 2007 at 5.37% at year-end 2006	**-**	1,000
Industrial Development Bonds due 2012 through 2038 at 3.50% - 5.75% at year-end 2007	**252**	252

and 3.60% - 5.75% at year-end 2006		
Guarantee of savings plan bank loan payable due 2015 at 5.40% at year-end 2007 and 5.65% at year-end 2006	**175**	203
Note payable to Merey Sweeny, L.P. due 2020 at 7%*	**172**	180
Marine Terminal Revenue Refunding Bonds due 2031 at 3.40% - 3.51% at year-end 2007 and 3.68% at year-end 2006	**265**	265
Other	**50**	60
Debt at face value	**20,945**	26,372
Capitalized leases	**54**	44
Net unamortized premiums and discounts	**688**	718
Total debt	**21,687**	27,134
Notes payable and long-term debt due within one year	**(1,398)**	(4,043)
Long-term debt	**$ 20,289**	23,091

**Related party.*

Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2008 through 2012 are: $1,398 million, $1,320 million, $1,483 million, $5,215 million and $2,028 million, respectively. At year-end 2007, notes payable and long-term debt due within one year of $1,398 million includes $1 billion of our Floating Rate Five-Year Term Note due 2011 repaid in January 2008, and $300 million of our 7.125% Debentures due 2028 that will be redeemed in March 2008.

At December 31, 2007, we had classified $725 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.

Effective January 15, 2007, we redeemed the 8% Junior Subordinated Deferrable Interest Debentures due 2037 (Subordinated Debt Securities II), at a premium of $14 million, plus accrued interest. This redemption resulted in the immediate redemption by Phillips 66 Capital II of $350 million of 8% Capital Securities. Under the provisions of revised FASB Interpretation No. 46, Consolidation of Variable Interest Entities (FIN 46 (R)), Trust II, a variable interest entity, was not consolidated in our financial statements because we were not the primary beneficiary. However, the Subordinated Debt Securities II ($361 million) was included on our consolidated balance sheet in Notes payable and long-term debt due within one year at December 31, 2006.

Also, in January 2007, we redeemed our $153 million 7.25% Notes due 2007 upon their maturity. In February 2007, we reduced our Floating Rate Five-Year Term Note due 2011 from $5 billion to $4 billion, with a subsequent reduction in July 2007 to $3 billion. In April 2007, we redeemed our $1 billion Floating Rate Notes due 2007 upon their maturity. In October 2007, we redeemed $300 million of Floating Rate Notes due 2009 at par plus accrued interest.

In May 2007, Polar Tankers Inc., a wholly owned subsidiary, issued an offering of $645 million 5.951% Notes due 2037. The notes are fully and unconditionally guaranteed by ConocoPhillips and ConocoPhillips Company.

In September 2007, we replaced our $5 billion and $2.5 billion revolving credit facilities, with one $7.5 billion revolving credit facility, expiring in September 2012. This facility may be used as direct bank borrowings, as support for the ConocoPhillips $7.5 billion commercial paper program, as support for the ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program, or as support for issuances of letters of credit totaling up to $750 million. The facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or covenants requiring maintenance of specified financial ratios or ratings. The credit agreement contains 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. At December 31, 2007 and 2006, we had no outstanding borrowings under these credit facilities, but $41 million in letters of credit had been issued at both dates. Under both commercial paper programs there was $725 million of commercial paper outstanding at December 31, 2007, compared with $2,931 million at December 31, 2006.

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.

In December 2007, we terminated interest rate swaps on $350 million of our 4.75% Notes due 2012. No interest rate swaps remain on any of our debt.

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Note 16 Joint Venture Acquisition Obligation

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

Quarterly principal and interest payments of $237 million began in the second quarter of 2007, and will continue until the balance is paid. Of the principal obligation amount, approximately $593 million was short-term at December 31, 2007, and is included in the Accounts payable related parties line on our consolidated balance sheet. The principal portion of these payments, which totaled $425 million in 2007, is presented on our consolidated statement of cash flows as an other financing activity. 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 an additional capital contribution and is included in the Capital expenditures and investments line on our consolidated statement of cash flows.

Note 17 Guarantees

At December 31, 2007, 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.

Construction Completion Guarantees

In June 2006, we issued a guarantee for 24 percent of the $2 billion in credit facilities of Rockies Express Pipeline LLC (Rockies Express), which will be used to construct a natural gas pipeline across a portion of the United States. At December 31, 2007, Rockies Express had $1,625 million outstanding under the credit facilities, with our 24 percent guarantee equaling $390 million. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $480 million, which could become payable if the credit facility is fully utilized and Rockies Express fails to meet its obligations under the credit agreement. In addition, we also have a guarantee for 24 percent of $600 million of Floating Rate Notes due 2009 issued by Rockies Express in September 2007. It is anticipated final construction completion will be achieved in 2009, and refinancing will take place at that time, making the debt non-recourse to ConocoPhillips. At December 31, 2007, the total carrying value of these guarantees to third-party lenders was $12 million. See Note 7 Variable Interest Entities (VIEs), for additional information.

In December 2005, we issued a construction completion guarantee for 30 percent of the $4.0 billion in loan facilities of Qatargas 3, which will be used to construct an LNG train in Qatar. Of the $4.0 billion in loan facilities, ConocoPhillips has 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 non-recourse to ConocoPhillips upon certified completion, which is expected in 2010. At December 31, 2007, the carrying value of the guarantee to the third-party lenders was $11 million. For additional information, see Note 10 Investments, Loans and Long-Term Receivables.

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Guarantees of Joint-Venture Debt

At December 31, 2007, we had guarantees outstanding for our portion of joint-venture debt obligations, which have terms of up to 17 years. The maximum potential amount of future payments under the guarantees is approximately $90 million. Payment would be required if a joint venture defaults on its debt obligations.

Other Guarantees

The Merey Sweeny, L.P. (MSLP) joint-venture project agreement requires the partners in the venture to pay cash calls to cover operating expenses in the event the venture does not have enough cash to cover operating expenses after setting aside the amount required for debt service over the next 17 years. Although there is no maximum limit stated in the agreement, the intent is to cover short-term cash deficiencies should they occur. Our maximum potential future payments under the agreement are currently estimated to be $100 million, assuming such a shortfall exists at some point in the future due to an extended operational disruption.

In February 2003, we entered into two agreements establishing separate guarantee facilities of $50 million each for two LNG ships. Subject to the terms of each such facility, we will be required to make payments should the charter revenue generated by the respective ship fall below certain specified minimum thresholds, and we will receive payments to the extent that such revenues exceed those thresholds. The net maximum future payments that we may have to make over the 20-year terms of the two agreements could be up to $100 million in total. To the extent we receive any such payments, our actual gross payments over the 20 years could exceed that amount. In the event either ship is sold or a total loss occurs, we also may have recourse to the sales or insurance proceeds to recoup payments made under the guarantee facilities. For additional information, see Note 7 Variable Interest Entities (VIEs).

We have guarantees of the residual value of leased corporate aircraft. The maximum potential payment under these guarantees at December 31, 2007, was $150 million.

In December 2007, we acquired a 50 percent equity interest in the Keystone Oil Pipeline (Keystone) to form a 50/50 joint venture with TransCanada Corporation. Keystone plans to construct a crude oil pipeline originating in Hardisty, Alberta, with delivery points at Wood River and Patoka, Illinois, and Cushing, Oklahoma. In connection with certain planning and construction activities, agreements were put in place with third parties to guarantee the payments due. Our maximum potential amount of future payments under those agreements are estimated to be $400 million, which could become payable if Keystone fails to meet its obligations under the agreements noted above and the obligation cannot otherwise be mitigated. Payments under the guarantees are contingent upon the partners not making necessary equity contributions into Keystone; therefore, it is considered unlikely that payments would be required. All but $15 million of the guarantees will terminate after construction is completed, currently estimated to be in 2010.

We have other guarantees with maximum future potential payment amounts totaling $200 million, which consist primarily of dealer and jobber loan guarantees to support our marketing business, guarantees to fund the short-term cash liquidity deficits of certain joint ventures, one small construction completion guarantee, guarantees relating to the startup of a refining joint venture, and guarantees of the lease payment obligations of a joint venture. These guarantees generally extend up to 10 years or life of the venture and payment would be required only if the dealer, jobber or lessee goes into default, if the joint ventures have cash liquidity issues, if a construction project is not completed, if a guaranteed party defaults on lease payments, or if an adverse decision occurs in the pending lawsuit.

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Indemnifications
Over the years, we have entered into various agreements to sell ownership interests in certain corporations and joint ventures and have sold several assets, including downstream and midstream assets, certain exploration and production assets, and downstream retail and wholesale sites 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, 2007, was $471 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 carrying amount recorded were $294 million of environmental accruals for known contamination that is included in asset retirement obligations and accrued environmental costs at December 31, 2007. For additional information about environmental liabilities, see Note 18 Contingencies and Commitments.

Note 18 Contingencies and Commitments
In the case of all known non-income-tax-related contingencies, 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 adopted FIN 48, effective January 1, 2007. FIN 48 requires a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain. See Note 2 Changes in Accounting Principles and Note 24 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 that are particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes.

Environmental
We are subject to federal, state and local environmental laws and regulations. These may result in obligations to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various sites. When we prepare our consolidated financial statements, we record accruals for environmental liabilities based on management s best estimates, using all information that is available at the time. We measure estimates and base liabilities on currently available facts, existing technology, and presently enacted laws and regulations, taking into

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

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

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and comparable state sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except those acquired in a purchase business combination, which we record on a discounted basis) for planned investigation and remediation activities for sites where it is probable that 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 14 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 which have been scheduled for trial, as well as the pace of settlement discussions in individual matters. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization believes that there is only a remote likelihood 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.

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, 2007, we had performance obligations secured by letters of credit of $1,200 million (of which $41 million was issued under the provisions of our revolving credit facilities, and the remainder was issued as direct bank letters of credit) and various purchase commitments for materials, supplies, services and items of permanent investment incident to the ordinary conduct of business.

See Note 13 Impairments, for additional information about expropriated assets in Venezuela and the contingencies related to receiving adequate compensation for our oil interests in Venezuela.

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

We have certain throughput agreements and take-or-pay agreements that are 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: 2008 $97 million; 2009 $97 million; 2010 $97 million; 2011 $98 million; 2012 $97 million; and 2013 and after $542 million. Total payments under the agreements were $67 million in 2007, $66 million in 2006 and $52 million in 2005.

Note 19 Financial Instruments and Derivative Contracts

Derivative Instruments

We, and certain of our subsidiaries, may use financial and commodity-based derivative contracts to manage exposures to fluctuations in foreign currency exchange rates, commodity prices, and interest rates, or to exploit 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 without approval from the Chief Executive Officer. The Authority Limitations document also authorizes the Chief Executive Officer to establish the maximum 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, while the Senior Vice President of Commercial monitors commodity price risk. Both report to the Chief Executive Officer. The Commercial organization manages our commercial marketing, optimizes our commodity flows and positions, monitors related risks of our upstream and downstream businesses and selectively takes price risk to add value.

SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS No. 133), requires companies to recognize all derivative instruments as either assets or liabilities on the balance sheet at fair value. Assets and liabilities resulting from derivative contracts open at December 31 were:

	Millions of Dollars	
	2007	2006
Derivative Assets		
Current	$ **453**	924
Long-term	**89**	82
	$ **542**	1,006
Derivative Liabilities		
Current	$ **493**	681
Long-term	**67**	126
	$ **560**	807

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These derivative assets and liabilities appear as prepaid expenses and other current assets, other assets, other accruals, or other liabilities and deferred credits on the balance sheet.

In June 2005, we acquired two limited-term, fixed-volume overriding royalty interests in Utah and the San Juan Basin related to our natural gas production. As part of the acquisition, we assumed related commodity swaps with a negative fair value of $261 million at June 30, 2005. In late June and early July of 2005, we entered into additional commodity swaps to essentially offset any remaining exposure from the assumed swaps. At December 31, 2007 and 2006, the commodity swaps assumed in the acquisition had a negative fair value of $29 million and $76 million, respectively, and the commodity swaps entered into to offset the resulting exposure had a positive fair value of $2 million and a negative fair value of $6 million, respectively.

The accounting for changes in fair value (i.e., gains or losses) of a derivative instrument depends on whether it meets the qualifications for, and has been designated as, a SFAS No. 133 hedge, and the type of hedge. At this time, we are not using SFAS No. 133 hedge accounting. All gains and losses, realized or unrealized, from derivative contracts not designated as SFAS No. 133 hedges have been recognized in the consolidated income statement. 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.

SFAS No. 133 also requires purchase and sales contracts for commodities that are readily convertible to cash (e.g., crude oil, natural gas, and gasoline) to be recorded on the balance sheet as derivatives unless the contracts are for quantities we expect to use or sell over a reasonable period in the normal course of business (the normal purchases and normal sales exception), among other requirements, and we have documented our intent to apply this exception. Except for contracts to buy or sell natural gas, we generally apply this exception to eligible purchase and sales contracts; however, we may elect not to apply this exception (e.g., when another derivative instrument will be used to mitigate the risk of the purchase or sale contract but hedge accounting will not be applied). When this occurs, both the purchase or sales contract and the derivative contract mitigating the resulting risk will be recorded on the balance sheet at fair value in accordance with the preceding paragraphs. Most of our contracts to buy or sell natural gas are recorded on the balance sheet as derivatives, except for certain long-term contracts to sell our natural gas production, for which we have elected the normal purchases and normal sales exception or which do not meet the SFAS No. 133 definition of a derivative.

Interest Rate Derivative Contracts At the beginning of 2004, we held interest rate swaps that converted $1.5 billion of debt from fixed to floating rates, but during 2005 we terminated the majority of these interest rate swaps as we redeemed the associated debt. This reduced the amount of debt being converted from fixed to floating by the end of 2005 to $350 million. In December 2007, we sold our positions in these remaining swaps for approximately $3 million, terminating the hedge.

Currency Exchange Rate Derivative Contracts 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 exposures to foreign currency rate risk. Examples include firm commitments for capital projects, certain local currency tax payments and dividends, short-term intercompany loans between subsidiaries operating in different countries, and cash returns from net investments in foreign affiliates to be remitted within the coming year.

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

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however, executive management may elect to use derivative instruments to hedge the price risk of our crude oil and natural gas production, as well as refinery margins.

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 may also be settled by physical delivery of the commodity, providing another source of supply to meet our refinery requirements or marketing demand.

- Meet customer needs. Consistent with our policy to generally remain exposed to market prices, we use swap contracts to convert fixed-price sales contracts, which are often requested by natural gas and refined product consumers, to a floating market price.

- Manage the risk to our cash flows from price exposures on specific crude oil, natural gas, refined product and electric power transactions.

- Enable us to use the market knowledge gained from these activities to do a limited amount of trading not directly related to our physical business. For the years ended December 31, 2007, 2006 and 2005, the gains or losses from this activity were not material to our cash flows or net income.

Credit Risk

Our financial instruments that are potentially exposed to concentrations of credit risk consist primarily of cash equivalents, over-the-counter derivative contracts, and trade receivables. Our cash equivalents are placed in high-quality commercial paper, money market funds and time deposits with major international banks and financial institutions. The credit risk from our over-the-counter derivative contracts, such as forwards and swaps, derives from the counterparty to the transaction, typically a major bank or financial institution. We closely monitor these credit exposures against predetermined credit limits, including the continual exposure adjustments that result from market movements. Individual counterparty exposure is managed within these limits, and includes the use of cash-call margins when appropriate, thereby reducing the risk of significant non-performance. We also use futures contracts, but futures have a negligible credit risk because they are traded on the New York Mercantile Exchange or the ICE Futures.

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

Fair Values of Financial Instruments

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

- Cash and cash equivalents: The carrying amount reported on the balance sheet approximates fair value.

- Accounts and notes receivable: The carrying amount reported on the balance sheet approximates fair value.

- Investment in LUKOIL shares: See Note 10 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 year-end effective yield rate of 4.9 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 16 Joint Venture Acquisition Obligation, for additional information.

Swaps: Fair value is estimated based on forward market prices and approximates the net gains and losses that would have been realized if the contracts had been closed out at year-end. When forward market prices are not available, they are estimated using the forward prices of a similar commodity with adjustments for differences in quality or location.

Futures: Fair values are based on quoted market prices obtained from the New York Mercantile Exchange, the ICE Futures, or other traded exchanges.

Forward-exchange contracts: Fair value is estimated by comparing the contract rate to the forward rate in effect on December 31 and approximates the net gains and losses that would have been realized if the contracts had been closed out at year-end.

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

	Millions of Dollars			
	Carrying Amount		Fair Value	
	2007	2006	**2007**	2006
Financial assets				
Foreign currency derivatives	$ **47**	47	**47**	47
Commodity derivatives	**495**	959	**495**	959
Financial liabilities				
Total debt, excluding capital leases	**21,633**	27,090	**23,101**	27,741
Joint venture acquisition obligation	**6,887**	-	**7,031**	-
Foreign currency derivatives	**29**	26	**29**	26
Interest rate derivatives	**-**	10	**-**	10
Commodity derivatives	**531**	771	**531**	771

Note 20 Preferred Stock and Minority Interests

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, 2007 or 2006.

Minority Interests

The minority interest owner in Ashford Energy Capital S.A. is entitled to a cumulative annual preferred return on its investment, based on three-month LIBOR rates plus 1.32 percent. The preferred return at December 31, 2007 and 2006, was 6.55 percent and 6.69 percent, respectively. At December 31, 2007 and 2006, the minority interest was $508 million, for both periods. Ashford Energy Capital S.A. continues to be consolidated in our financial statements under the provisions of FIN 46(R) because we are the primary beneficiary. See Note 7 Variable Interest Entities (VIEs), for additional information.

The remaining minority interest amounts are primarily related to equity in less than wholly owned consolidated subsidiaries. The largest amount, $648 million at December 31, 2007, and $672 million at December 31, 2006, relates to Darwin LNG located in northern Australia.

Note 21 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 acquiror 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 acquiror 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 acquiror, whose rights will become void) to purchase, for the then exercise price, a number of shares of ConocoPhillips common stock equal in value to two times the exercise price of the right. In addition, the rights enable holders to purchase the stock of an acquiring company at a discount, depending on specific circumstances. We may redeem the rights in whole, but not in part, for one cent per right.

Note 22 Non-Mineral Leases

The company leases ocean transport vessels, railcars, corporate aircraft, service stations, computers, office buildings and other facilities and equipment. Certain leases include escalation clauses for adjusting rentals 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, 2007, future minimum rental payments due under non-cancelable leases were:

	Millions of Dollars
2008	$ 732
2009	593
2010	439
2011	340
2012	397
Remaining years	807
Total	3,308
Less income from subleases	(186)*
Net minimum operating lease payments	$ 3,122

**Includes $90 million related to railroad cars subleased to CPChem, a related party.*

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

	Millions of Dollars		
	2007	2006	2005
Total rentals*	**$ 855**	698	564
Less sublease rentals	**(82)**	(103)	(66)
	$ 773	595	498

* *Includes $27 million, $29 million and $28 million of contingent rentals in 2007, 2006 and 2005, respectively. Contingent rentals primarily are related to retail sites and refining equipment, and are based on volume of product sold or throughput.*

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Note 23 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	
	2007		2006		**2007**	2006
	U.S.	**Int l.**	U.S.	Int l.		
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 4,113**	**3,087**	3,703	2,495	**778**	815
Service cost	**175**	**98**	174	87	**14**	14
Interest cost	**229**	**161**	210	134	**45**	47
Plan participant contributions	**-**	**10**	-	9	**28**	31
Medicare Part D subsidy	**-**	**-**	-	-	**6**	6
Plan amendments	**2**	**(68)**	1	-	**-**	(26)
Actuarial (gain) loss	**109**	**(294)**	57	79	**(6)**	(59)
Acquisitions	**-**	**-**	275	42	**-**	36
Divestitures	**-**	**-**	-	-	**-**	-
Benefits paid	**(347)**	**(97)**	(307)	(77)	**(81)**	(86)
Curtailment	**-**	**1**	-	-	**-**	-
Recognition of termination benefits	**-**	**1**	-	1	**-**	-
Foreign currency exchange rate change	**-**	**186**	-	317	**8**	-
Benefit obligation at December 31*	**$ 4,281**	**3,085**	4,113	3,087	**792**	778
**Accumulated benefit obligation portion of above at December 31:*	***$ 3,666***	***2,550***	*3,493*	*2,585*		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	**$ 2,863**	**2,185**	2,183	1,725	**3**	3
Acquisitions	**-**	**-**	214	44	**-**	-
Divestitures	**-**	**-**	-	-	**-**	-
Actual return on plan assets	**237**	**169**	356	142	**-**	-
Company contributions	**385**	**185**	417	120	**47**	49
Plan participant contributions	**-**	**10**	-	9	**28**	31
Medicare Part D subsidy	**-**	**-**	-	-	**6**	6
Benefits paid	**(347)**	**(97)**	(307)	(77)	**(81)**	(86)
Foreign currency exchange rate change	**-**	**149**	-	222	**-**	-
Fair value of plan assets at December 31:	**$ 3,138**	**2,601**	2,863	2,185	**3**	3

Funded Status	**$ (1,143)**	**(484)**	(1,250)	(902)	**(789)**	(775)

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		Millions of Dollars					
		Pension Benefits				Other Benefits	
		2007		2006		**2007**	2006
		U.S.	**Int l.**	U.S.	Int l.		
Amounts Recognized in the Consolidated Balance Sheet at December 31							
Noncurrent assets	$		**98**		16		
Current liabilities		**(6)**	**(9)**	(3)	(11)	**(50)**	(48)
Noncurrent liabilities		**(1,137)**	**(573)**	(1,247)	(907)	**(739)**	(727)
Total recognized	$	**(1,143)**	**(484)**	(1,250)	(902)	**(789)**	(775)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31							
Discount rate		**6.00%**	**5.90**	5.75	5.15	**6.20**	5.95
Rate of compensation increase		**4.00**	**4.80**	4.00	4.70		
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31							
Discount rate		**5.75%**	**5.15**	5.50	5.05	**5.95**	5.70
Expected return on plan assets		**7.00**	**6.50**	7.00	6.50	**7.00**	7.00
Rate of compensation increase		**4.00**	**4.70**	4.00	4.35		

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.

All of our plans use a December 31 measurement date, except for a plan in the United Kingdom, which has a September 30 measurement date. To comply with the provisions of SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R), in 2008 the measurement date for the U.K. plan will be changed to December 31, which is expected to result in a $10 million charge to retained earnings.

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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	
	2007		2006		**2007**	2006
	U.S.	**Int l.**	U.S.	Int l.		
Unrecognized net actuarial loss (gain)	$ **587**	**123**	577	460	**(185)**	(200)
Unrecognized prior service cost	**71**	**(30)**	79	44	**15**	28

	Millions of Dollars		
	2007		
	Pension Benefits		Other Benefits
	U.S.	**Int l.**	
Sources of Change in Other Comprehensive Income			
Net gain (loss) arising during the period	**$ (72)**	**289**	**5**
Amortization of gain (loss) included in income	**62**	**48**	**(20)**
Net gain (loss) during the period	**$ (10)**	**337**	**(15)**
Prior service cost arising during the period	**$ (2)**	**67**	**-**
Amortization of prior service cost included in income	**10**	**7**	**13**
Net prior service cost during the period	**$ 8**	**74**	**13**

Amounts included in accumulated other comprehensive income at December 31, 2007, that are expected to be amortized into net periodic postretirement cost during 2008 are provided below:

	Millions of Dollars		
	Pension		Other Benefits
	U.S.	Int l.	
Unrecognized net actuarial loss (gain)	$ 64	12	(19)
Unrecognized prior service cost	10	1	13

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 $6,392 million, $5,417 million, and $5,056 million at December 31, 2007, respectively, and $6,366 million, $5,400 million, and $4,543 million at December 31, 2006, respectively.

For our unfunded non-qualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $390 million and $344 million, respectively, at December 31, 2007, and were $345 million and $304 million, respectively, at December 31, 2006.

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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		
	2007		2006		2005		**2007**	2006	2005
	U.S.	**Int l.**	U.S.	Int l.	U.S.	Int l.			
Components of Net Periodic Benefit Cost									
Service cost	**$ 175**	**98**	174	87	151	69	**14**	14	19
Interest cost	**229**	**161**	210	134	174	122	**45**	47	48
Expected return on plan assets	**(204)**	**(147)**	(169)	(121)	(126)	(105)			
Amortization of prior service cost	**10**	**7**	9	7	4	7	**13**	19	19
Recognized net actuarial loss (gain)	**62**	**48**	89	41	55	33	**(20)**	(16)	(6)
Net periodic benefit cost	**$ 272**	**167**	313	148	258	126	**52**	64	80

We recognized pension settlement losses of $2 million and $11 million, special termination benefits of $1 million and $1 million, and curtailment losses of $1 million and $0 in 2007 and 2006, respectively.

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 gains and losses, we amortize 10 percent of the unamortized balance each year.

We have multiple non-pension postretirement benefit plans for health and life insurance. The health care plans are contributory, with participant and company contributions adjusted annually; the life insurance plans are non-contributory. For most groups of retirees, any increase in the annual health care escalation rate above 4.5 percent is borne by the participant. The weighted-average health care cost trend rate for those pre-65 participants not subject to the cap is assumed to decrease gradually from 9.0 percent in 2008 to 5.5 percent in 2015. For post-65 participants not subject to the cap, the weighted-average health care cost trend rate is assumed to decrease gradually from 10.0 percent in 2008 to 5.5 percent in 2020.

The assumed health care cost trend rate impacts the amounts reported. A one-percentage-point change in the assumed health care cost trend rate would have the following effects on the 2007 amounts:

	Millions of Dollars	
	One-Percentage-Point	
	Increase	Decrease
Effect on total of service and interest cost components	$ 2	(3)
Effect on the postretirement benefit obligation	33	(39)

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Plan Assets We follow a policy of broadly diversifying pension plan assets across asset classes, investment managers, and individual holdings. 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. Our funding policy for U.S. plans is to contribute at least the minimum required by the Employee Retirement Income Security Act of 1974. Contributions to foreign plans are dependent upon local laws and tax regulations. In 2008, we expect to contribute approximately $460 million to our domestic qualified and non-qualified benefit plans and $177 million to our international qualified and non-qualified benefit plans.

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. At December 31, 2007, the participating interest in the annuity contract was valued at $159 million and consisted of $201 million in debt securities and $229 million in equity securities, less $271 million for the accumulated benefit obligation covered by the contract. At December 31, 2006, the participating interest was valued at $181 million and consisted of $412 million in debt securities and $53 million in equity securities, less $284 million for the accumulated benefit obligation covered by the contract. 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.

In the United States, plan asset allocation is managed on a gross asset basis, which includes the market value of all investments held under the insurance annuity contract. On this basis, the weighted-average asset allocations are as follows:

	Pension					
	U.S.			International		
	2007	2006	Target	**2007**	2006	Target
Asset Category						
Equity securities	**64%**	66	60	**48**	50	51
Debt securities	**36**	33	30	**46**	44	43
Real estate			5	**5**	5	5
Other		1	5	**1**	1	1
	100%	100	100	**100**	100	100

The above asset allocations are all within guidelines established by plan fiduciaries.

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Treating the participating interest in the annuity contract as a separate asset category results in the following weighted-average asset allocations:

	Pension			
	U.S.		International	
	2007	2006	**2007**	2006
Asset Category				
Equity securities	**62%**	72	**48**	50
Debt securities	**33**	21	**46**	44
Participating interest in annuity contract	**5**	6	**-**	-
Real estate	**-**	-	**5**	5
Other	**-**	1	**1**	1
	100%	100	**100**	100

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.	Gross	Subsidy Receipts
2008	$ 326	98	55	7
2009	294	107	57	8
2010	320	111	60	9
2011	356	116	63	9
2012	391	123	64	10
2013-2017	2,537	730	342	61

Defined Contribution Plans

Most U.S. employees (excluding retail service station employees) are eligible to participate in either the ConocoPhillips Savings Plan (CPSP) or the Burlington Resources Savings Plan (BR Savings Plan). Employees can deposit up to 30 percent of their pay in the thrift feature of the CPSP to a choice of approximately 32 investment funds. ConocoPhillips matches 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 $21 million in 2007, $19 million in 2006, and $18 million in 2005. For the BR Savings Plan, ConocoPhillips matches deposits, up to 6 percent or 8 percent of the employee s eligible pay based upon years of service. During 2007, ConocoPhillips contributed $5 million to the BR Savings Plan, to match eligible contributions by employees.

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 their salaries and receiving an allocation of shares of common stock proportionate to their contributions.

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 2008 through 2011, when no debt principal payments are scheduled to occur, the company has 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 $148 million, $126 million and $124 million in 2007, 2006 and 2005, respectively, all of which was compensation expense. In 2007, 2006 and 2005, we contributed 1,856,224 shares, 1,921,688 shares and 2,250,727 shares, respectively, of company common stock from the Compensation and Benefits Trust. The shares had a fair market value of $155 million, $132 million and $130 million, respectively. Dividends used to service debt were $39 million, $37 million and $32 million in 2007, 2006 and 2005, respectively. These dividends reduced the amount of compensation expense recognized each period. Interest incurred on the CPSP debt in 2007, 2006 and 2005 was $11 million, $12 million and $9 million, respectively.

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

	2007	2006
Unallocated shares	**9,040,949**	10,499,837
Allocated shares	**17,648,368**	18,501,772
Total shares	**26,689,317**	29,001,609

The fair value of unallocated shares at December 31, 2007 and 2006, was $798 million and $755 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 $44 million in 2007, $39 million in 2006 and $27 million in 2005.

Share-Based Compensation Plans

The 2004 Omnibus Stock and Performance Incentive Plan (the Plan) was approved by shareholders in May 2004. 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. After approval of the Plan, the heritage plans were no longer used for further awards. Of the 70 million shares available for issuance under the Plan, 40 million shares of common stock are available for incentive stock options, and no more than 40 million shares may be used 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), we recognize expense over the period of time during which the employee earns the award, accelerating the recognition of expense only when an employee actually retires. For share-based awards granted after our adoption of SFAS No. 123(R) on January 1, 2006, we recognize share-based compensation expense over the shorter

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of: 1) the service period (i.e., the stated period of time required to earn the award); or 2) the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement, but not less than six months, as this is the minimum period of time required for an award to not be subject to forfeiture.

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

Total share-based compensation expense recognized in income and the associated tax benefit for the three years ended December 31, 2007, was as follows:

	Millions of Dollars		
	2007	2006	2005
Compensation cost	**$ 242**	140	226
Tax benefit	**85**	54	84

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, 2007:

	Options	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Millions of Dollars Aggregate Intrinsic Value
Outstanding at December 31, 2004	74,263,922	$ 25.97		
Granted	2,567,000	47.87	$ 10.92	
Exercised	(19,265,175)	24.85		$ 615
Forfeited/expired	(169,001)	34.83		
Outstanding at December 31, 2005	57,396,746	$ 27.31		
Burlington Resources acquisition at March 31, 2006	4,927,116	33.95		
Granted	1,809,281	59.33	$ 16.16	
Exercised	(9,737,765)	24.32		$ 416
Forfeited	(341,759)	60.58		
Expired	(4,840)	50.16		
Outstanding at December 31, 2006	54,048,779	$ 29.31		
Granted	**2,530,648**	**66.37**	**$ 17.86**	
Exercised	**(12,176,988)**	**26.29**		**$ 926**
Forfeited	**(268,177)**	**65.02**		
Expired or cancelled	**(29,407)**	**17.00**		
Outstanding at December 31, 2007	**44,104,855**	**$ 32.06**		
Vested at December 31, 2007	**41,386,111**	**$ 30.26**		**$ 2,407**
Exercisable at December 31, 2007	**39,721,035**	**$ 28.86**		**$ 2,366**

The weighted-average remaining contractual term of vested options and exercisable options at December 31, 2007, was 4.44 years and 4.26 years, respectively.

During 2007, we received $316 million in cash and realized a tax benefit of $191 million from the exercise of options. At December 31, 2007, the remaining unrecognized compensation expense from unvested options was $18 million, which will be recognized over a weighted-average period of 11 months, the longest period being 25 months.

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

	2007	2006	2005
Assumptions used			
Risk-free interest rate	**4.77%**	4.63	3.92
Dividend yield	**2.50%**	2.50	2.50
Volatility factor	**26.10%**	26.10	22.50
Expected life (years)	**6.70**	7.18	7.18

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The ranges in the assumptions used were as follows:

	2007		2006		2005	
	High	**Low**	High	Low	High	Low
Ranges used						
Risk-free interest rate	**4.90%**	**4.77**	5.15	4.54	4.45	3.33
Dividend yield	**2.50**	**2.50**	2.50	2.50	2.50	2.50
Volatility factor	**26.10**	**26.10**	26.50	25.90	25.70	22.30

We calculate volatility using all of the ConocoPhillips end-of-week closing stock prices available since the merger of Conoco and Phillips Petroleum on August 31, 2002, and will continue to do so until the span of data used equals 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.

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The following summarizes our stock unit activity for the three years ended December 31, 2007:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2004	2,316,690	$ 32.10	
Granted	1,668,192	46.95	
Forfeited	(57,262)	37.81	
Issued	(35,216)		$ 2
Outstanding at December 31, 2005	3,892,404	$ 38.34	
Granted	1,480,294	57.77	
Forfeited	(118,461)	45.92	
Issued	(167,099)		$ 11
Outstanding at December 31, 2006	5,087,138	$ 43.75	
Granted	**1,721,521**	**65.33**	
Forfeited	**(162,992)**	**52.57**	
Issued	**(975,756)**		**$ 36**
Outstanding at December 31, 2007	**5,669,911**	**$ 51.30**	
Not Vested at December 31, 2007	**5,314,557**	**$ 50.61**	

At December 31, 2007, the remaining unrecognized compensation cost from the unvested units was $124 million, which will be recognized over a weighted-average period of 23 months, the longest period being 49 months.

Performance Share Program Under the Plan, we also annually grant to senior management stock units that do not vest until the employee becomes eligible for retirement, so we recognize compensation expense for these awards beginning on the date of grant and ending on the date the employee becomes eligible for retirement; however, since these awards are authorized three years prior to the grant date, for employees eligible for 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, generally when the employee retires from ConocoPhillips. 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.

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The following summarizes our Performance Share Program activity for the two years ended December 31, 2007:

	Performance Share Stock Units	Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2005	-	-	
Granted	1,641,216	$ 59.08	
Forfeited/cancelled	-		
Issued	(184,975)		$ 12
Outstanding at December 31, 2006	1,456,241	$ 59.08	
Granted	**1,349,475**	**66.37**	
Forfeited	**(22,062)**		
Issued	**(178,357)**		**$ 12**
Outstanding at December 31, 2007	**2,605,297**	**$ 62.49**	
Not Vested at December 31, 2007	**1,198,599**	**$ 41.97**	

At December 31, 2007, the remaining unrecognized compensation cost from unvested Performance Share awards was $50 million, which will be recognized over a weighted-average period of 49 months, the longest period being 13 years.

Other In addition to the above active programs, we have outstanding shares of restricted stock and restricted stock units that were either issued to replace awards held by employees of companies we acquired or issued as part of a compensation program that has been discontinued. Generally, the recipients of the restricted shares or units receive a quarterly dividend or dividend equivalent.

The following summarizes the aggregate activity of these restricted shares and units for the three years ended December 31, 2007:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2004	3,461,899	$ 28.44	
Granted	89,676	54.08	
Stock swaps	9,116	43.97	
Issued	(135,168)		$ 7
Cancelled	(80,582)	28.93	
Outstanding at December 31, 2005	3,344,941	$ 29.16	
Granted	248,421	64.48	
Burlington Resources acquisition	523,769	64.95	
Issued	(239,257)		$ 16
Cancelled	(275,499)	47.56	
Outstanding at December 31, 2006	3,602,375	$ 33.68	
Granted	**293,024**	**67.30**	
Issued	**(227,766)**		**$ 17**
Cancelled	**(180,489)**	**50.39**	

Outstanding at December 31, 2007	**3,487,144**	**$ 34.41**
Not Vested at December 31, 2007	**370,303**	**$ 65.65**

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At December 31, 2007, the remaining unrecognized compensation cost from the unvested units was $12 million, which will be recognized over a weighted-average period of 18 months, the longest period being 25 months.

Compensation and Benefits Trust

The Compensation and Benefits Trust (CBT) is an irrevocable grantor trust, administered by an independent trustee and designed to acquire, hold and distribute shares of our common stock to fund certain future compensation and benefit obligations of the company. The CBT does not increase or alter the amount of benefits or compensation that will be paid under existing plans, but offers us enhanced financial flexibility in providing the funding requirements of those plans. We also have flexibility in determining the timing of distributions of shares from the CBT to fund compensation and benefits, subject to a minimum distribution schedule. The trustee votes shares held by the CBT in accordance with voting directions from eligible employees, as specified in a trust agreement with the trustee.

We sold 58.4 million shares of previously unissued company common stock to the CBT in 1995 for $37 million of cash, previously contributed to the CBT by us, and a promissory note from the CBT to us of $952 million. The CBT is consolidated by ConocoPhillips; therefore, the cash contribution and promissory note are eliminated in consolidation. Shares held by the CBT are valued at cost and do not affect earnings per share or total common stockholders equity until after they are transferred out of the CBT. In 2007 and 2006, shares transferred out of the CBT were 1,856,224 and 1,921,688, respectively. At December 31, 2007, the CBT had 42.2 million shares remaining. All shares are required to be transferred out of the CBT by January 1, 2021. The CBT, together with two smaller grantor trusts, comprise the Grantor trusts line in the equity section of the consolidated balance sheet.

Note 24 Income Taxes

Income taxes charged to income from continuing operations were:

	Millions of Dollars		
	2007	2006	2005
Income Taxes			
Federal			
Current	**$ 3,944**	4,313	3,434
Deferred	**312**	(77)	375
Foreign			
Current	**7,035**	7,581	5,093
Deferred	**(474)**	392	384
State and local			
Current	**602**	622	538
Deferred	**(38)**	(48)	83
	$ 11,381	12,783	9,907

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	
	2007	2006
Deferred Tax Liabilities		
Properties, plants and equipment, and intangibles	**$ 23,344**	22,733
Investment in joint ventures	**1,300**	1,178
Inventory	**197**	339
Partnership income deferral	**1,501**	1,305
Other	**725**	438
Total deferred tax liabilities	**27,067**	25,993
Deferred Tax Assets		
Benefit plan accruals	**1,603**	1,730
Asset retirement obligations and accrued environmental costs	**3,135**	2,330
Deferred state income tax	**390**	408
Other financial accruals and deferrals	**539**	820
Loss and credit carryforwards	**1,716**	1,283
Other	**251**	230
Total deferred tax assets	**7,634**	6,801
Less valuation allowance	**(1,269)**	(822)
Net deferred tax assets	**6,365**	5,979
Net deferred tax liabilities	**$ 20,702**	20,014

Current assets, long-term assets, current liabilities and long-term liabilities included deferred taxes of $329 million, $26 million, $39 million and $21,018 million, respectively, at December 31, 2007, and $173 million, $62 million, $175 million and $20,074 million, respectively, at December 31, 2006.

We have loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2008 and 2027 with some carryovers having indefinite carryforward periods.

Valuation allowances have been established for certain loss and credit carryforwards that reduce deferred tax assets to an amount that will, more likely than not, be realized. Uncertainties that may affect the realization of these assets include tax law changes and the future level of product prices and costs. During 2007, valuation allowances increased a total of $447 million. This reflects increases of $849 million primarily related to U.S. foreign tax credit and foreign tax loss carryforwards, partially offset by decreases of $402 million primarily related to foreign loss carryforwards (asset dispositions and relinquishment). The balance includes valuation allowances for certain deferred tax assets of $229 million, for which subsequently recognized tax benefits, if any, will be allocated to goodwill. Based on our historical taxable income, expectations for the future, and available tax-planning strategies, management expects that 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, 2007 and 2006, income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $4,381 million and $3,597 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.

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In June 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48). This Interpretation provides guidance on recognition, classification and disclosure concerning uncertain tax liabilities. The evaluation of a tax position requires recognition of a tax benefit if it is more likely than not it will be sustained upon examination. We adopted FIN 48 effective January 1, 2007. The adoption did not have a material impact on our consolidated financial statements.
The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2007.

	Millions of Dollars
Balance at January 1	$ 912
Additions based on tax positions related to the current year	273
Additions for tax positions of prior years	145
Reductions for tax positions of prior years	(168)
Settlements	(15)
Lapse of statute	(4)
Balance at December 31, 2007	$ 1,143

Included in the balance of unrecognized tax benefits was $698 million which, if recognized, would affect our effective tax rate.
At December 31, 2007, accrued liabilities for interest and penalties totaled $137 million, net of accrued income taxes. Interest and penalties affecting earnings in 2007 were $46 million.
We and our subsidiaries file tax returns in the U.S. federal jurisdiction and in many foreign and state jurisdictions. Audits in major jurisdictions, including the United States, Canada, Norway and the United Kingdom, are generally complete through 2001. 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 to 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 from continuing operations 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		
	2007	2006	2005	**2007**	2006	2005
Income from continuing operations before income taxes						
United States	**$ 13,939**	13,376	12,486	**59.9%**	47.2	53.0
Foreign	**9,333**	14,957	11,061	**40.1**	52.8	47.0
	$ 23,272	28,333	23,547	**100.0%**	100.0	100.0
Federal statutory income tax	**$ 8,145**	9,917	8,241	**35.0%**	35.0	35.0
Foreign taxes in excess of federal statutory rate	**3,254**	2,697	1,562	**14.0**	9.5	6.6
Federal manufacturing deduction	**(250)**	(119)	(106)	**(1.1)**	(.4)	(.4)
State income tax	**367**	373	404	**1.6**	1.3	1.7
Other	**(135)**	(85)	(194)	**(.6)**	(.3)	(.8)
	$ 11,381	12,783	9,907	**48.9%**	45.1	42.1

Our effective tax rate in 2007 was 49 percent, compared with 45 percent in 2006. The change in the effective tax rate for 2007 was primarily due to the impact of the expropriation of our oil interests in Venezuela in the second quarter of 2007. This impact was partially offset by the effect of income tax law changes enacted during 2007, and by a higher proportion of income in higher tax rate jurisdictions during 2006.

Our 2007 tax expense was decreased $204 million and $141 million, respectively, due to remeasurement of deferred tax liabilities resulting from tax rate reductions in Canada and Germany. Our 2006 tax expense was increased $470 million due to remeasurement of deferred tax liabilities and the current year impact of increases in the U.K. tax rate. This was mostly offset by a 2006 reduction in tax expense of $435 million due to the remeasurement of deferred tax liabilities from the 2006 Canadian graduated tax rate reduction and an Alberta provincial tax rate change. Our 2005 tax expense was reduced $38 million due to the remeasurement of deferred tax liabilities from the 2003 Canadian graduated tax rate reduction.

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Note 25 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
2007			
Defined benefit pension plans:			
Prior service cost arising during the year	**$ 65**	**20**	**45**
Reclassification adjustment for amortization of prior service cost included in net income	**30**	**12**	**18**
Net prior service cost	**95**	**32**	**63**
Net gain arising during the year	**222**	**67**	**155**
Reclassification adjustment for amortization of prior net losses included in net income	**90**	**32**	**58**
Net gain	**312**	**99**	**213**
Non-sponsored plans*	**(2)**	**-**	**(2)**
Foreign currency translation adjustments	**3,214**	**139**	**3,075**
Hedging activities	**(3)**	**1**	**(4)**
Other comprehensive income	**$ 3,616**	**271**	**3,345**
2006			
Minimum pension liability adjustment	$ 53	20	33
Foreign currency translation adjustments	913	(100)	1,013
Hedging activities	4	-	4
Other comprehensive income	$ 970	(80)	1,050
2005			
Minimum pension liability adjustment	$ (101)	(45)	(56)
Unrealized loss on securities	(10)	(4)	(6)
Foreign currency translation adjustments	(786)	(69)	(717)
Hedging activities	(3)	(4)	1
Other comprehensive loss	$ (900)	(122)	(778)

**Plans for which ConocoPhillips is not the primary obligor primarily those administered by equity affiliates.*

Deferred taxes have not been provided on temporary differences related to foreign currency translation adjustments for investments in certain foreign subsidiaries and foreign corporate joint ventures that are considered permanent in duration.

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Accumulated other comprehensive income in the equity section of the balance sheet included:

	Millions of Dollars	
	2007	2006
Defined benefit pension liability adjustments	**$ (465)**	(665)
Foreign currency translation adjustments	**5,033**	1,958
Deferred net hedging loss	**(8)**	(4)
Accumulated other comprehensive income	**$ 4,560**	1,289

Note 26 Cash Flow Information

	Millions of Dollars		
	2007	2006	2005
Non-Cash Investing and Financing Activities			
Issuance of stock and options for the acquisition of Burlington Resources	**$ -**	16,343	-
Investment in an upstream business venture through issuance of an acquisition obligation	**7,313**	-	-
Investment in a downstream business venture through contribution of non-cash assets and liabilities	**2,428**	-	-
Increase in properties, plants and equipment (PP&E) resulting from our payment obligations to acquire an ownership interest in producing properties in Libya	**-**	-	732
Increase in PP&E related to an increase in asset retirement obligations	**919**	464	511
Cash Payments			
Interest	**$ 1,040**	958	500
Income taxes	**11,330**	13,050	8,507

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Note 27 Other Financial Information

	Millions of Dollars Except Per Share Amounts		
	2007	2006	2005
Interest and Debt Expense			
Incurred			
Debt	$ **1,369**	1,409	807
Other	**449**	136	85
	1,818	1,545	892
Capitalized	**(565)**	(458)	(395)
Expensed	$ **1,253**	1,087	497
Other Income			
Interest income	$ **342**	165	127
Gain on asset dispositions	**1,348**	116	278
Business interruption insurance recoveries*	**52**	239	-
Other	**229**	165	60
	$ **1,971**	685	465

**Primarily related to 2005 hurricanes in the Gulf of Mexico and southern United States.*

Research and Development Expenditures expensed	$ **160**	117	125
Advertising Expenses	$ **84**	87	84
Shipping and Handling Costs*	$ **1,493**	1,415	1,265

**Amounts included in E&P production and operating expenses.*

Cash Dividends paid per common share	$ **1.64**	1.44	1.18
Foreign Currency Transaction Gains (Losses) after-tax			
E&P	$ **216**	(44)	7
Midstream	**(2)**	-	7
R&M	**(13)**	60	(52)
LUKOIL Investment	**5**	-	(1)
Chemicals	**-**	-	-
Emerging Businesses	**1**	1	(1)
Corporate and Other	**(120)**	65	(42)

$	**87**	82	(82)

Note 28 Related Party Transactions
Significant transactions with related parties were:

	Millions of Dollars		
	2007	2006*	2005*
Operating revenues (a)	**$ 10,949**	8,808	7,719
Purchases (b)**	**15,722**	7,072	6,089
Operating expenses and selling, general and administrative expenses (c)	**416**	386	380
Net interest expense (d)	**99**	(13)	30

**Restated to include additional related party transactions.*
***The increase in 2007 is primarily due to purchases from the WRB Refining business venture.*

(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 Chevron Phillips Chemical Company LLC (CPChem), gas oil and hydrogen feedstocks were sold to Excel Paralubes and refined products were sold primarily to CFJ Properties and LUKOIL. Natural gas, crude oil, blendstock and other intermediate products were sold to WRB Refining LLC. We also sold various international marketing companies to LUKOIL in the second quarter of 2007. In addition, we charged several of our affiliates including CPChem, Merey Sweeny L.P. (MSLP) and Hamaca Holding LLC (until expropriation on June 26, 2007) for the use of common facilities, such as steam generators, waste and water treaters, and warehouse facilities.

(b) We purchased refined products from WRB Refining. We purchased natural gas and natural gas liquids from DCP Midstream and CPChem for use in our refinery processes and other feedstocks from various affiliates. We purchased crude oil from LUKOIL, upgraded crude oil from Petrozuata C.A. (until expropriation on June 26, 2007) and refined products from MRC. We also paid fees to various pipeline equity companies for transporting finished refined products and a price upgrade to MSLP for heavy crude processing. We purchased base oils and fuel products from Excel Paralubes for use in our refinery and specialty businesses.

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

(d) We paid and/or received interest to/from various affiliates, including FCCL Oil Sands Partnership. See Note 10 Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.

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Note 29 Segment Disclosures and Related Information

We have organized our reporting structure based on the grouping of similar products and services, resulting in six operating segments:

1) E&P This segment primarily explores for, produces, transports and markets crude oil, natural gas and natural gas liquids on a worldwide basis. At December 31, 2007, our E&P operations were producing in the United States, Norway, the United Kingdom, the Netherlands, Canada, Nigeria, Ecuador, Argentina, offshore Timor-Leste in the Timor Sea, Australia, China, Indonesia, Algeria, Libya, Vietnam, 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, primarily in the United States and Trinidad. The Midstream segment primarily consists of our 50 percent equity investment in DCP Midstream.

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, 2007, 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 LUKOIL, an international, integrated oil and gas company headquartered in Russia. At December 31, 2007, our ownership interest was 20 percent based on issued shares, and 20.6 percent based on estimated shares outstanding. See Note 10 Investments, Loans and Long-Term Receivables, for additional information.

5) Chemicals This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists of our 50 percent equity investment in 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 other items, such as carbon-to-liquids, technology solutions, and alternative energy and programs, such as advanced hydrocarbon processes, energy conversion technologies, new petroleum-based products, and renewable fuels.

Corporate and Other includes general corporate overhead, most interest income and expense, discontinued operations, restructuring charges, and various other corporate activities. Corporate assets include all cash and cash equivalents.

We evaluate performance and allocate resources based on net income. Segment accounting policies are the same as those in Note 1 Accounting Policies. Intersegment sales are at prices that approximate market.

Also, see Note 2 Changes in Accounting Principles, for information affecting the comparability of sales and other operating revenues presented in the following tables of our segment disclosures.

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Analysis of Results by Operating Segment

	Millions of Dollars		
	2007	2006	2005
Sales and Other Operating Revenues			
E&P			
United States	**$ 36,974**	35,335	35,159
International	**24,617**	28,111	21,692
Intersegment eliminations U.S.	**(6,096)**	(5,438)	(4,075)
Intersegment eliminations international	**(7,341)**	(7,842)	(4,251)
E&P	**48,154**	50,166	48,525
Midstream			
Total sales	**5,106**	4,461	4,041
Intersegment eliminations	**(245)**	(1,037)	(955)
Midstream	**4,861**	3,424	3,086
R&M			
United States	**96,154**	95,314	97,251
International	**38,598**	35,439	30,633
Intersegment eliminations U.S.	**(540)**	(855)	(593)
Intersegment eliminations international	**(11)**	(21)	(11)
R&M	**134,201**	129,877	127,280
LUKOIL Investment	**-**	-	-
Chemicals	**10**	13	14
Emerging Businesses*			
Total sales	**656**	675	618
Intersegment eliminations	**(458)**	(515)	(426)
Emerging Businesses	**198**	160	192
Corporate and Other	**13**	10	13
Other adjustments*	**-**	-	332
Consolidated sales and other operating revenues	**$ 187,437**	183,650	179,442

**Sales and other operating revenues for 2005 in the Emerging Businesses segment have been restated to reflect intersegment eliminations on sales from the Immingham power plant (Emerging Businesses segment) to the Humber refinery (R&M segment). Since these amounts were not material to the consolidated income statement, the Other adjustments line above is required to reconcile the restated Emerging Businesses revenues to the consolidated income statement.*

Depreciation, Depletion, Amortization and Impairments

E&P			
United States	**$ 3,328**	2,901	1,402
International	**9,121**	3,445	1,914
Total E&P	**12,449**	6,346	3,316
Midstream	**14**	29	61
R&M			
United States	**609**	1,014	633
International	**139**	458	193
Total R&M	**748**	1,472	826
LUKOIL Investment	**-**	-	-
Chemicals	**-**	-	-
Emerging Businesses	**39**	58	32
Corporate and Other	**78**	62	60
Consolidated depreciation, depletion, amortization and impairments	**$ 13,328**	7,967	4,295

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	Millions of Dollars		
	2007	2006	2005
Equity in Earnings of Affiliates			
E&P			
United States	**$ 11**	20	19
International	**302**	782	825
Total E&P	**313**	802	844
Midstream	**599**	618	829
R&M			
United States	**1,710**	466	388
International	**240**	151	227
Total R&M	**1,950**	617	615
LUKOIL Investment	**1,875**	1,481	756
Chemicals	**350**	665	413
Emerging Businesses	**-**	5	-
Corporate and Other	**-**	-	-
Consolidated equity in earnings of affiliates	**$ 5,087**	4,188	3,457
Income Taxes			
E&P			
United States	**$ 2,231**	2,545	2,349
International	**6,372**	7,584	5,145
Total E&P	**8,603**	10,129	7,494
Midstream	**237**	248	214
R&M			
United States	**2,571**	2,334	2,124
International	**113**	218	212
Total R&M	**2,684**	2,552	2,336
LUKOIL Investment	**45**	37	25
Chemicals	**(13)**	171	93
Emerging Businesses	**(33)**	(2)	(18)
Corporate and Other	**(142)**	(352)	(237)
Consolidated income taxes	**$ 11,381**	12,783	9,907

Net Income (Loss)			
E&P			
United States	**$ 4,248**	4,348	4,288
International	**367**	5,500	4,142
Total E&P	**4,615**	9,848	8,430
Midstream	**453**	476	688
R&M			
United States	**4,615**	3,915	3,329
International	**1,308**	566	844
Total R&M	**5,923**	4,481	4,173
LUKOIL Investment	**1,818**	1,425	714
Chemicals	**359**	492	323
Emerging Businesses	**(8)**	15	(21)
Corporate and Other	**(1,269)**	(1,187)	(778)
Consolidated net income	**$ 11,891**	15,550	13,529

	Millions of Dollars		
	2007	2006	2005
Investments In and Advances To Affiliates			
E&P			
United States	**$ 1,059**	690	336
International	**12,055**	4,346	3,789
Total E&P	**13,114**	5,036	4,125
Midstream	**1,178**	1,319	1,446
R&M			
United States	**3,500**	698	662
International	**1,091**	948	819
Total R&M	**4,591**	1,646	1,481
LUKOIL Investment	**11,162**	9,564	5,549
Chemicals	**2,203**	2,255	2,158
Emerging Businesses	**79**	-	-
Corporate and Other	**-**	-	18
Consolidated investments in and advances to affiliates*	**$ 32,327**	19,820	14,777
**Includes amounts classified as held for sale:*	***$ 48***	*158*	-
Total Assets			
E&P			
United States	**$ 35,160**	35,523	18,434
International	**59,412**	48,143	31,662
Goodwill	**25,569**	27,712	11,423
Total E&P	**120,141**	111,378	61,519
Midstream	**2,016**	2,045	2,109
R&M			
United States	**24,336**	22,936	20,693
International	**9,766**	9,135	6,096
Goodwill	**3,767**	3,776	3,900
Total R&M	**37,869**	35,847	30,689
LUKOIL Investment	**11,164**	9,564	5,549
Chemicals	**2,225**	2,379	2,324
Emerging Businesses	**1,230**	977	858
Corporate and Other	**3,112**	2,591	3,951

Consolidated total assets	**$ 177,757**	164,781	106,999
Capital Expenditures and Investments*			
E&P			
United States	**$ 3,788**	2,828	1,637
International	**6,147**	6,685	5,047
Total E&P	**9,935**	9,513	6,684
Midstream	**5**	4	839
R&M			
United States	**1,146**	1,597	1,537
International	**240**	1,419	201
Total R&M	**1,386**	3,016	1,738
LUKOIL Investment	**-**	2,715	2,160
Chemicals	**-**	-	-
Emerging Businesses	**257**	83	5
Corporate and Other	**208**	265	194
Consolidated capital expenditures and investments	**$ 11,791**	15,596	11,620

**Net of cash acquired.*

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Additional information on items included in Corporate and Other (on a before-tax basis unless otherwise noted):

	Millions of Dollars		
	2007	2006	2005
Interest income*	**$ 246**	106	113
Interest and debt expense**	**1,066**	1,087	497
**In addition, the E&P segment had interest income of:*	***$ 96***	*57*	*12*
***In addition, the E&P segment had interest expense of:*	***187***	-	-

Geographic Information

	Millions of Dollars						
	United States	Norway	United Kingdom	Canada	Russia	Other Foreign Countries	Worldwide Consolidated
2007							
Sales and Other Operating Revenues*	**$ 131,433**	**2,479**	**20,680**	**4,727**	**-**	**28,118**	**187,437**
Long-Lived Assets**	**$ 50,714**	**6,180**	**7,995**	**24,758**	**13,359**	**18,324**	**121,330**
2006							
Sales and Other Operating Revenues*	$ 127,869	2,480	19,510	5,554	-	28,237	183,650
Long-Lived Assets**	$ 48,418	4,982	7,755	14,831	10,886	19,149	106,021
2005							
Sales and Other Operating Revenues*	$ 130,874	3,280	19,043	5,676	-	20,569	179,442
Long-Lived Assets**	$ 33,161	4,380	5,564	5,328	6,342	14,671	69,446

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

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

Note 30 New Accounting Standards

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This Statement defines fair value, establishes a framework for its measurement and expands disclosures about fair value measurements. We use fair value measurements to measure, among other items, purchased assets and investments, derivative contracts and financial guarantees. We also use them to assess impairment of properties, plants and equipment, intangible assets and goodwill. The Statement does not apply to share-based payment transactions and inventory pricing. In February 2008, the FASB issued a FASB Staff Position (FSP) on Statement No. 157 that permits a one-year delay of the effective date for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We will adopt this Statement effective January 1, 2008, with the exceptions allowed under the FSP described above and do not expect any significant impact to our consolidated financial statements, other than additional disclosures.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115. This Statement permits an entity to choose to measure financial instruments and certain other items similar to financial instruments at fair value, with all subsequent changes in fair value for the financial instrument reported in earnings. By electing the fair value option in conjunction with a derivative, an entity can achieve an accounting result similar to a fair value hedge without having to comply with complex hedge accounting rules. We will adopt this Statement effective January 1, 2008, and do not expect any significant impact to our consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141 (Revised), Business Combinations (SFAS No. 141(R)). This Statement will apply to all transactions in which an entity obtains control of one or more other businesses. In general, SFAS No. 141(R) requires the acquiring entity in a business combination to recognize the fair value of all the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date as the fair value measurement point; and modifies the disclosure requirements. This Statement applies prospectively to business combinations for which the acquisition date is on or after January 1, 2009. However, accounting for changes in valuation allowances for acquired deferred tax assets and the resolution of uncertain tax positions for prior business combinations will impact tax expense instead of impacting the prior business combination accounting starting January 1, 2009. We are currently evaluating the changes provided in this Statement.

Also in December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51, which changes the classification of non-controlling interests, sometimes called a minority interest, in the consolidated financial statements. Additionally, this Statement establishes a single method of accounting for changes in a parent company s ownership interest that do not result in deconsolidation and requires a parent company to recognize a gain or loss when a subsidiary is deconsolidated. This Statement is effective January 1, 2009, and will be applied prospectively with the exception of the presentation and disclosure requirements which must be applied retrospectively for all periods presented. We are currently evaluating the impact on our consolidated financial statements.

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Oil and Gas Operations (Unaudited)

In accordance with SFAS No. 69, Disclosures about Oil and Gas Producing Activities, 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. While this information was developed with reasonable care and disclosed in good faith, we emphasize some of the data is necessarily imprecise and represents only approximate amounts because of the subjective judgments involved in developing such information. Accordingly, this information may not necessarily represent our current financial condition or our expected future results.

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 segment, as well as in our LUKOIL Investment segment. As a result, amounts reported as Equity Affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report. The data included for the LUKOIL Investment segment reflects the company s estimated share of OAO LUKOIL s (LUKOIL) amounts. Because LUKOIL s accounting cycle close and preparation of U.S. GAAP financial statements occur subsequent to our reporting deadline, our equity share of financial information and statistics for our LUKOIL investment are estimated based on current market indicators, publicly available LUKOIL operating results, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. Our estimated year-end 2007 reserves related to our equity investment in LUKOIL are based on LUKOIL s year-end 2007 reserve estimates and include adjustments to conform them to ConocoPhillips reserve policy.

The information about our proportionate share of equity affiliates is necessary for a full understanding of our operations because equity affiliate operations are an integral part of the overall success of our oil and gas operations.

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 go up then our applicable reserve quantities would decline. At December 31, 2007, approximately 12 percent of our total proved reserves, excluding LUKOIL, were under PSCs, primarily in our Asia Pacific geographic reporting area.

Our disclosures by geographic area for our consolidated operations include the United States (U.S.), Canada, Europe (primarily Norway and the United Kingdom), Asia Pacific, Middle East and Africa, Russia and Caspian, and Other Areas (primarily South America). In these supplemental oil and gas disclosures, where we use equity accounting for operations that have proved reserves, these operations are shown separately and designated as Equity Affiliates, and include Canada, Middle East and Africa, Russia and Caspian, and Other Areas. Canada includes our share of FCCL Oil Sands Partnership (FCCL). Middle East and Africa includes Qatargas 3. The Russia and Caspian area includes our share of Polar Lights Company, OOO Naryanmarneftegaz, and LUKOIL. Other Areas consists of the Petrozuata and Hamaca heavy-oil projects in Venezuela, which were expropriated on June 26, 2007.

Reserves Governance

The recording and reporting of proved reserves are governed by criteria established by regulations of the SEC. Those regulations define proved reserves as those estimated quantities of hydrocarbons that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves are further classified as either developed or undeveloped. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods, while proved undeveloped reserves are the quantities expected to be recovered from new wells on undrilled acreage, or from an existing well where relatively major expenditures are 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, geophysicists 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 composed of reservoir engineers, geologists, geophysicists and finance personnel for adherence to SEC guidelines and company policy through on-site visits and review of documentation. In addition to providing independent reviews of the business units recommended reserve changes, 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 their findings to senior management and internal audit. 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 crude oil, natural gas and natural gas liquids reserves held by consolidated companies have been estimated by ConocoPhillips. Our policy with respect to equity affiliates is either to estimate the proved reserve quantities ourselves (applicable to those situations where we have a substantial engineering presence), or to rely on estimates prepared by the equity affiliate, and perform a reasonableness review of those assessments. Of the proved reserves attributable to equity affiliates at year-end 2007, 38 percent was based on assessments of the available data performed by ConocoPhillips. The remaining 62 percent, reflecting our equity interest in LUKOIL, was based on estimates prepared by the equity affiliate. These equity-affiliate-prepared estimates are reviewed by ConocoPhillips and adjusted to comply with our internal reserves governance policies.

In addition, during 2007, approximately 43 percent of our year-end 2006 E&P proved reserves were reviewed by an outside unrelated third-party petroleum engineering consulting firm. At the present time, we plan to continue to have an outside firm review a pro rata portion of a similar percentage of our reserve base over the next two years.

Engineering estimates of the quantities of recoverable oil and gas reserves in oil and gas fields and in-place crude bitumen volumes in oil sand mining operations 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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n **Proved Reserves Worldwide**

Years Ended December 31	Crude Oil Millions of Barrels Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
Developed and Undeveloped											
End of 2004	1,536	170	1,706	47	851	255	127	181	-	3,167	1,982
Revisions	31	6	37	4	34	7	(21)	(11)	-	50	6
Improved recovery	15	1	16	-	-	-	-	-	-	16	-
Purchases	-	3	3	-	-	-	238	20	-	261	515
Extensions and discoveries	31	13	44	1	17	49	4	-	17	132	60
Production	(108)	(21)	(129)	(8)	(94)	(37)	(20)	-	-	(288)	(130)
Sales	-	(2)	(2)	-	-	-	-	-	-	(2)	(3)
End of 2005	1,505	170	1,675	44	808	274	328	190	17	3,336	2,430
Revisions	(118)	(11)	(129)	58	(65)	(12)	(18)	(74)	2	(238)	(35)
Improved recovery	13	1	14	-	5	63	-	-	-	82	-
Purchases	-	181	181	16	-	13	42	-	17	269	393
Extensions and discoveries	53	9	62	4	6	8	3	-	-	83	74
Production	(97)	(37)	(134)	(9)	(90)	(39)	(39)	-	(3)	(314)	(171)
Sales	-	(18)	(18)	-	-	-	-	-	-	(18)	(1)
End of 2006	1,356	295	1,651	113	664	307	316	116	33	3,200	2,690
Revisions	24	19	43	28	10	(23)	(13)	1	(3)	43	202
Improved recovery	25	16	41	-	-	-	-	-	-	41	-
Purchases	-	-	-	-	-	-	-	-	-	-	403
Extensions and discoveries	26	15	41	3	8	73	16	-	-	141	303
Production	(96)	(36)	(132)	(7)	(76)	(32)	(29)	-	(4)	(280)	(172)
Sales	-	(1)	(1)	(16)	(1)	(6)	-	-	(17)	(41)	(1,028)
End of 2007	1,335	308	1,643	121	605	319	290	117	9	3,104	2,398
Equity affiliates											
End of 2004	-	-	-	-	-	-	-	800	1,182	-	1,982
End of 2005	-	-	-	-	-	-	46	1,295	1,089	-	2,430
End of 2006	-	-	-	-	-	-	60	1,607	1,023	-	2,690
End of 2007	-	-	-	623	-	-	70	1,705	-	-	2,398

Developed

Consolidated operations											
End of 2004	1,415	148	1,563	46	429	207	121	-	-	2,366	-
End of 2005	1,359	158	1,517	42	409	202	326	-	-	2,496	-
End of 2006	1,254	281	1,535	50	359	181	292	-	13	2,430	-
End of 2007	1,238	281	1,519	51	337	146	259	-	9	2,321	-
Equity affiliates											
End of 2004	-	-	-	-	-	-	-	624	491	-	1,115
End of 2005	-	-	-	-	-	-	-	1,013	472	-	1,485
End of 2006	-	-	-	-	-	-	-	1,293	369	-	1,662
End of 2007	-	-	-	45	-	-	-	1,336	-	-	1,381

Notable changes in proved crude oil reserves in the three years ending December 31, 2007, included:

Revisions: In 2007 for our equity affiliate operations, revisions were primarily attributable to LUKOIL. In 2006, revisions in Alaska were primarily a result of reservoir performance.

Purchases: In 2007 for our equity affiliate operations, purchases reflect the formation of FCCL. In 2006, purchases in the Lower 48 were primarily related to our acquisition of Burlington Resources in March 2006. In 2006 and 2005 for our equity affiliate operations, purchases were mainly attributable to acquiring additional interests in LUKOIL. In 2005, purchases in the Middle East and Africa were attributable to our re-entry into Libya.

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Extensions and Discoveries: In 2007 for our equity affiliate operations, extensions and discoveries were primarily associated with FCCL.

Sales: In 2007 for our equity affiliates, sales were primarily due to the expropriation of our oil interests in Venezuela.

In addition to conventional crude oil, natural gas and natural gas liquids (NGL) proved reserves, we have proved oil sands mining reserves in Canada, associated with a Syncrude project totaling 221 million barrels at the end of 2007. For internal management purposes, we view these mining reserves and their development as part of our total exploration and production operations. However, SEC regulations define these reserves as mining related. Therefore, they are not included in our tabular presentation of proved crude oil, natural gas and NGL reserves. These oil sands mining reserves also are not included in the standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities.

Years Ended December 31	Natural Gas Billions of Cubic Feet Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
Developed and Undeveloped											
End of 2004	3,344	4,234	7,578	975	3,285	3,773	1,104	119	-	16,834	862
Revisions	260	(43)	217	72	83	(20)	-	(3)	-	349	51
Improved recovery	-	1	1	-	-	-	-	-	-	1	-
Purchases	7	163	170	-	1	8	-	13	-	192	453
Extensions and discoveries	5	270	275	78	79	85	2	-	5	524	1,212
Production	(144)	(449)	(593)	(155)	(386)	(146)	(45)	-	-	(1,325)	(30)
Sales	-	(62)	(62)	-	-	-	-	-	-	(62)	-
End of 2005	3,472	4,114	7,586	970	3,062	3,700	1,061	129	5	16,513	2,548
Revisions	43	(87)	(44)	(123)	(293)	71	(64)	(31)	(39)	(523)	(310)
Improved recovery	-	4	4	-	1	-	-	-	-	5	-
Purchases	6	5,258	5,264	2,466	432	25	94	-	129	8,410	325
Extensions and discoveries	23	551	574	353	64	6	58	-	-	1,055	925
Production	(130)	(770)	(900)	(356)	(414)	(233)	(62)	-	(6)	(1,971)	(99)
Sales	-	(43)	(43)	-	-	-	-	-	-	(43)	-
End of 2006	3,414	9,027	12,441	3,310	2,852	3,569	1,087	98	89	23,446	3,389
Revisions	120	446	566	(41)	91	(47)	(26)	-	(12)	531	(327)
Improved recovery	5	1	6	-	-	-	-	-	-	6	-
Purchases	-	30	30	-	-	-	-	-	-	30	-
Extensions and discoveries	5	539	544	143	29	28	23	-	-	767	364
Production	(113)	(835)	(948)	(404)	(369)	(224)	(55)	-	(7)	(2,007)	(103)
Sales	-	(5)	(5)	(170)	(20)	(74)	-	-	(5)	(274)	(384)
End of 2007	3,431	9,203	12,634	2,838	2,583	3,252	1,029	98	65	22,499	2,939
Equity affiliates											
End of 2004	-	-	-	-	-	-	-	661	201	-	862
End of 2005	-	-	-	-	-	-	1,063	1,197	288	-	2,548
End of 2006	-	-	-	-	-	-	1,573	1,429	387	-	3,389
End of 2007	-	-	-	-	-	-	1,925	1,014	-	-	2,939

Developed

Consolidated operations

End of 2004	3,194	3,989	7,183	934	2,467	1,520	522	-	-	12,626	-
End of 2005	3,316	3,966	7,282	918	2,393	2,600	1,060	-	-	14,253	-
End of 2006	3,336	7,484	10,820	2,672	2,314	3,105	1,029	-	24	19,964	-
End of 2007	3,344	7,417	10,761	2,328	2,177	2,857	963	-	26	19,112	-
Equity affiliates											
End of 2004	-	-	-	-	-	-	-	207	118	-	325
End of 2005	-	-	-	-	-	-	-	581	155	-	736
End of 2006	-	-	-	-	-	-	-	655	173	-	828
End of 2007	-	-	-	-	-	-	-	698	-	-	698

Natural gas production may differ from gas production (delivered for sale) in our statistics disclosure, primarily because the quantities above include gas consumed at the lease, but omit the gas equivalent of liquids extracted at any of our owned, equity-affiliate, or third-party processing plants or facilities.

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, 2007, included:

Purchases: In 2006 for our consolidated operations, purchases were primarily related to our acquisition of Burlington Resources.

Extensions and Discoveries: In 2006 for our equity affiliate operations, extensions and discoveries were primarily in Qatar and LUKOIL. In 2005, extensions and discoveries for our equity affiliate operations were primarily in Qatar.

Years Ended December 31	Natural Gas Liquids Millions of Barrels Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
Developed and Undeveloped											
End of 2004	153	88	241	26	48	71	4	-	-	390	-
Revisions	-	17	17	1	6	4	-	-	-	28	-
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	8	8	-	-	-	-	-	-	8	-
Extensions and discoveries	-	5	5	-	1	2	-	-	-	8	21
Production	(7)	(9)	(16)	(3)	(5)	(6)	(1)	-	-	(31)	-
Sales	-	(1)	(1)	-	-	-	-	-	-	(1)	-
End of 2005	146	108	254	24	50	71	3	-	-	402	21
Revisions	(1)	24	23	1	(4)	(1)	(1)	-	-	18	-
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	328	328	56	-	-	-	-	-	384	-
Extensions and discoveries	-	14	14	7	-	-	-	-	-	21	11
Production	(6)	(22)	(28)	(9)	(5)	(7)	-	-	-	(49)	-
Sales	-	(2)	(2)	-	-	-	-	-	-	(2)	-
End of 2006	139	450	589	79	41	63	2	-	-	774	32
Revisions	1	31	32	(4)	-	(2)	-	-	-	26	20
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	12	12	2	1	3	-	-	-	18	7
Production	(7)	(27)	(34)	(10)	(4)	(5)	(1)	-	-	(54)	-
Sales	-	-	-	(2)	-	(3)	-	-	-	(5)	-
End of 2007	133	466	599	65	38	56	1	-	-	759	59
Equity affiliates											
End of 2004	-	-	-	-	-	-	-	-	-	-	-
End of 2005	-	-	-	-	-	-	21	-	-	-	21
End of 2006	-	-	-	-	-	-	32	-	-	-	32
End of 2007	-	-	-	-	-	-	39	20	-	-	59
Developed											
Consolidated operations											
End of 2004	153	82	235	25	34	71	4	-	-	369	-

End of 2005	146	106	252	23	31	64	2	-	-	372	-
End of 2006	139	346	485	64	28	56	2	-	-	635	-
End of 2007	133	343	476	53	33	54	1	-	-	617	-
Equity affiliates											
End of 2004	-	-	-	-	-	-	-	-	-	-	-
End of 2005	-	-	-	-	-	-	-	-	-	-	-
End of 2006	-	-	-	-	-	-	-	-	-	-	-
End of 2007	-	-	-	-	-	-	-	18	-	-	18

Natural gas liquids reserves include estimates of natural gas liquids to be extracted from our leasehold gas at gas processing plants or facilities.

Notable changes in proved natural gas liquids reserves in the three years ended December 31, 2007, included:

Purchases: In 2006 for our consolidated operations, purchases were related to our acquisition of Burlington Resources.

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n **Results of Operations**

Year Ended December 31	Millions of Dollars Consolidated Operations										Equity
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Affiliates
2007											
Sales	$ 4,659	5,422	10,081	3,406	5,701	3,383	1,038	-	240	23,849	5,212
Transfers	2,344	2,986	5,330	-	2,729	267	1,157	-	-	9,483	3,427
Other revenues	173	94	267	430	330	252	201	1	3	1,484	71
Total revenues	7,176	8,502	15,678	3,836	8,760	3,902	2,396	1	243	34,816	8,710
Production costs excluding taxes	775	1,232	2,007	874	1,029	410	251	-	41	4,612	906
Taxes other than income taxes	1,663	628	2,291	70	45	129	18	2	98	2,653	3,675
Exploration expenses	104	318	422	247	105	130	77	24	12	1,017	68
Depreciation, depletion and amortization	583	2,559	3,142	1,661	1,394	608	204	-	-	7,009	551
Impairment expropriated assets	-	-	-	-	-	-	-	-	4,588	4,588	-
Property impairments	28	43	71	27	188	26	-	-	155	467	-
Transportation costs	412	553	965	137	335	101	24	-	64	1,626	770
Other related expenses	(64)	72	8	(96)	46	(26)	34	56	37	59	57
Accretion	37	48	85	47	132	9	3	1	-	277	7
	3,638	3,049	6,687	869	5,486	2,515	1,785	(82)	(4,752)	12,508	2,676
Provision for income taxes	1,248	1,091	2,339	237	3,595	982	1,545	(28)	1	8,671	844
Results of operations for producing activities	2,390	1,958	4,348	632	1,891	1,533	240	(54)	(4,753)	3,837	1,832
Other earnings	(135)	35	(100)	280	48	67	25	33	197	550	214
Net income (loss)	$ 2,255	1,993	4,248	912	1,939	1,600	265	(21)	(4,556)	4,387	2,046

Results of operations for producing activities of equity affiliates	$	-	-	-	98	-	-	(5)	1,554	185	-	1,832

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Year Ended December 31	Millions of Dollars Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
2006											
Sales*	$ 4,491	4,881	9,372	2,951	5,950	3,493	1,743	-	140	23,649	5,161
Transfers*	2,023	2,550	4,573	-	2,954	271	764	-	-	8,562	2,821
Other revenues	2	56	58	145	14	(8)	127	-	4	340	108
Total revenues	6,516	7,487	14,003	3,096	8,918	3,756	2,634	-	144	32,551	8,090
Production costs excluding taxes	708	893	1,601	706	814	324	215	-	27	3,687	739
Taxes other than income taxes	914	554	1,468	52	37	91	10	1	30	1,689	3,444
Exploration expenses	105	222	327	246	73	121	44	32	17	860	46
Depreciation, depletion and amortization	460	2,272	2,732	1,155	1,200	512	220	1	21	5,841	461
Property impairments	-	15	15	131	-	10	-	-	19	175	-
Transportation costs	610	555	1,165	104	316	89	18	-	10	1,702	420
Other related expenses	11	44	55	15	87	18	38	43	28	284	52
Accretion	34	36	70	39	97	8	2	-	-	216	6
	3,674	2,896	6,570	648	6,294	2,583	2,087	(77)	(8)	18,097	2,922
Provision for income taxes	1,409	1,064	2,473	(193)	4,578	1,061	1,931	(13)	(7)	9,830	891
Results of operations for producing activities	2,265	1,832	4,097	841	1,716	1,522	156	(64)	(1)	8,267	2,031
Other earnings	82**	169**	251	191	335	62	32	(4)	(25)	842	133
Net income (loss)	$ 2,347**	2,001**	4,348	1,032	2,051	1,584	188	(68)	(26)	9,109	2,164
Results of operations for	$ -	-	-	-	-	-	(6)	1,229	808	-	2,031

producing
activities of
equity
affiliates

**Certain amounts in Alaska, Lower 48, Asia Pacific, and the Middle East and Africa were reclassified. Total revenues were unchanged.*
***Restated to increase Alaska and reduce Lower 48 by $14 million related to overhead previously aligned with Alaska.*

Year Ended December 31	Millions of Dollars Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
2005											
Sales*	$ 4,102	3,385	7,487	1,642	5,142	2,795	423	-	-	17,489	3,470
Transfers*	1,997	1,206	3,203	-	2,207	26	640	-	-	6,076	1,458
Other revenues	2	168	170	40	(253)	11	4	-	-	(28)	38
Total revenues	6,101	4,759	10,860	1,682	7,096	2,832	1,067	-	-	23,537	4,966
Production costs excluding taxes	488	492	980	316	612	274	115	-	-	2,297	452
Taxes other than income taxes	537	311	848	33	41	26	18	1	1	968	1,635
Exploration expenses	120	66	186	147	87	139	69	33	8	669	56
Depreciation, depletion and amortization	443	848	1,291	399	1,074	329	53	-	-	3,146	288
Property impairments	-	1	1	13	(10)	-	-	-	-	4	-
Transportation costs	665	350	1,015	53	296	64	5	-	-	1,433	255
Other related expenses	67	48	115	(12)	28	38	32	35	17	253	26
Accretion	29	19	48	16	84	7	2	-	-	157	1
	3,752	2,624	6,376	717	4,884	1,955	773	(69)	(26)	14,610	2,253
Provision for income taxes	1,342	900	2,242	228	3,311	747	759	(6)	(13)	7,268	673
Results of operations for producing activities	2,410	1,724	4,134	489	1,573	1,208	14	(63)	(13)	7,342	1,580
Other earnings	141	15	156	93	64	7	(28)	(2)	26	316	(90)
Cumulative effect of accounting change	1	(3)	(2)	-	(2)	-	-	-	-	(4)	-
	$ 2,552	1,736	4,288	582	1,635	1,215	(14)	(65)	13	7,654	1,490

Net income (loss)													
Results of operations for producing activities of equity affiliates	$	-	-	-	-	-	-	(11)	773	818		-	1,580

**Certain amounts in Alaska were reclassified. Total revenues were unchanged.*

- n Results of operations for producing activities consist of all the activities within the E&P organization and producing activities within the LUKOIL Investment segment, except for pipeline and marine operations, liquefied natural gas operations, a Canadian Syncrude operation, 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.

- n Transfers are valued at prices that approximate market.

- n Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income. Also included in 2005 were losses of approximately $282 million for the mark-to-market valuation of certain U.K. gas contracts.

- n Production costs are those incurred to operate and maintain wells and related equipment and facilities used to produce petroleum liquids and natural gas. These costs also include depreciation of support equipment and administrative expenses related to the production activity.

- n Taxes other than income taxes include production, property and other non-income taxes.

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- Exploration expenses include dry hole, leasehold impairment, geological and geophysical expenses, the cost 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 29 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 oil, natural gas or natural gas liquids 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 the oil and gas producing activity. The net income of the transportation operations is included in other earnings.
- Other related expenses include foreign currency 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 the oil and gas producing activities that are reflected in our consolidated income tax expense for the period, multiplying the result by the country s statutory tax rate and adjusting for applicable tax credits. Included in 2007 for Canada is a benefit related to the remeasurement of deferred tax liabilities from the 2007 Canadian graduated tax rate reduction. Included in 2006 for Canada is a $353 million benefit (which excludes $48 million related to the Syncrude oil project reflected in other earnings) related to the remeasurement of deferred tax liabilities from the 2006 Canadian graduated tax rate reduction and an Alberta provincial tax rate change. Europe income tax expense for 2006 was increased $250 million due to remeasurement of deferred tax liabilities as a result of increases in the U.K. tax rate.

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n Statistics

Net Production	**2007**	2006	2005
	Thousands of Barrels Daily		
Crude Oil			
Consolidated operations			
Alaska	**261**	263	294
Lower 48	**102**	104	59
United States	**363**	367	353
Canada	**19**	25	23
Europe	**210**	245	257
Asia Pacific	**87**	106	100
Middle East and Africa	**81**	106	53
Other areas	**10**	7	-
Total consolidated	**770**	856	786
Equity affiliates			
Canada	**27**	-	-
Russia and Caspian	**416**	375	250
Other areas	**42**	101	106
Total equity affiliates	**485**	476	356
Natural Gas Liquids*			
Consolidated operations			
Alaska	**19**	17	20
Lower 48	**79**	62	30
United States	**98**	79	50
Canada	**27**	25	10
Europe	**14**	13	13
Asia Pacific	**14**	18	16
Middle East and Africa	**2**	1	2
Total consolidated	**155**	136	91

**Represents amounts extracted attributable to E&P operations (see natural gas liquids reserves for further discussion). Includes for 2007, 2006 and 2005, 14,000, 11,000, and 9,000 barrels daily in Alaska, respectively, that were sold from the Prudhoe Bay lease to the Kuparuk lease for re-injection to enhance crude oil production.*

	Millions of Cubic Feet Daily		
Natural Gas*			
Consolidated operations			
Alaska	**110**	145	169
Lower 48	**2,182**	2,028	1,212

United States	**2,292**	2,173	1,381
Canada	**1,106**	983	425
Europe	**961**	1,065	1,023
Asia Pacific	**579**	582	350
Middle East and Africa	**125**	142	84
Other areas	**19**	16	-
Total consolidated	**5,082**	4,961	3,263
Equity affiliates			
Russia and Caspian	**256**	244	67
Other areas	**5**	9	7
Total equity affiliates	**261**	253	74

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

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Average Sales Price	**2007**	2006	2005
Crude Oil Per Barrel			
Consolidated operations			
Alaska	**$ 69.75**	62.66	52.24
Lower 48	**63.49**	57.04	45.24
United States	**68.00**	61.09	51.09
Canada	**61.77**	54.25	44.70
Europe	**71.81**	64.05	53.16
Asia Pacific	**70.23**	61.93	51.34
Middle East and Africa	**72.18**	66.59	52.93
Other areas	**60.84**	50.63	-
Total international	**70.79**	63.38	52.27
Total consolidated	**69.47**	62.39	51.74
Equity affiliates			
Canada	**37.94**	-	-
Russia and Caspian	**50.00**	41.61	37.39
Other areas	**47.46**	46.40	38.08
Total equity affiliates	**49.13**	42.66	37.60
Natural Gas Liquids Per Barrel			
Consolidated operations			
Alaska	**$ 71.85**	61.06	51.30
Lower 48	**44.43**	38.10	36.43
United States	**46.00**	40.35	40.40
Canada	**50.85**	45.62	42.20
Europe	**45.72**	38.78	31.25
Asia Pacific	**53.19**	43.95	40.11
Middle East and Africa	**8.31**	8.15	7.39
Total international	**48.80**	42.89	36.25
Total consolidated	**47.13**	41.50	38.32
Natural Gas Per Thousand Cubic Feet			
Consolidated operations			
Alaska	**$ 3.68**	3.59	2.75
Lower 48	**5.99**	6.14	7.28
United States	**5.98**	6.11	7.12
Canada	**6.09**	5.67	7.25
Europe	**7.87**	7.78	5.77
Asia Pacific	**6.37**	5.91	5.24
Middle East and Africa	**.80**	.70	.67
Other areas	**1.18**	1.31	-
Total international	**6.51**	6.27	5.78
Total consolidated	**6.26**	6.20	6.32

Equity affiliates			
Russia and Caspian	**1.02**	.57	.48
Other areas	**.30**	.30	.26
Total equity affiliates	**1.01**	.57	.46

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	2007	2006	2005
Average Production Costs Per Barrel of Oil Equivalent			
Consolidated operations			
Alaska	**$ 7.12**	6.38	3.91
Lower 48	**6.20**	4.85	4.63
United States	**6.52**	5.43	4.24
Canada	**10.40**	9.05	8.34
Europe	**7.34**	5.12	3.81
Asia Pacific	**5.69**	4.02	4.31
Middle East and Africa	**6.62**	4.51	4.57
Other areas	**8.53**	7.65	-
Total international	**7.68**	5.65	4.58
Total consolidated	**7.13**	5.55	4.43
Equity affiliates			
Canada	**13.32**	-	-
Russia and Caspian	**4.04**	3.53	2.69
Other areas	**6.24**	5.42	5.01
Total equity affiliates	**4.70**	3.91	3.36
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent			
Consolidated operations			
Alaska	**$ 15.27**	8.23	4.30
Lower 48	**3.16**	3.01	2.93
United States	**7.45**	4.98	3.67
Canada	**.83**	.67	.87
Europe	**.32**	.23	.26
Asia Pacific	**1.79**	1.13	.41
Middle East and Africa	**.47**	.21	.71
Other areas	**20.39**	8.50	-
Total international	**1.07**	.60	.42
Total consolidated	**4.10**	2.54	1.87
Equity affiliates			
Canada	**.21**	-	-
Russia and Caspian	**20.89**	21.40	17.12
Other areas	**11.21**	5.28	.06
Total equity affiliates	**19.05**	18.21	12.16
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent			
Consolidated operations			
Alaska	**$ 5.35**	4.14	3.55
Lower 48	**12.87**	12.35	7.98
United States	**10.21**	9.26	5.59
Canada	**19.76**	14.80	10.53

Europe	**9.94**	7.55	6.68
Asia Pacific	**8.43**	6.35	5.17
Middle East and Africa	**5.38**	4.61	2.10
Other areas	**-**	5.95	-
Total international	**11.40**	8.43	6.45
Total consolidated	**10.84**	8.80	6.07
Equity affiliates			
Canada	**6.82**	-	-
Russia and Caspian	**2.53**	2.04	1.55
Other areas	**3.88**	4.04	3.58
Total equity affiliates	**2.86**	2.43	2.14

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Net Wells Completed *(1)*		Productive			Dry	
	2007	2006	2005	**2007**	2006	2005
Exploratory *(2)*						
Consolidated operations						
Alaska	**3**	-	-	**1**	1	5
Lower 48	**71**	27	23	**9**	9	5
United States	**74**	27	23	**10**	10	10
Canada	**50**	8	26	**17**	7	7
Europe	**1**	1	1	**1**	1	*
Asia Pacific	**4**	2	7	**1**	2	3
Middle East and Africa	**-**	1	-	**1**	1	2
Russia and Caspian	**-**	-	-	*****	-	*
Other areas	**-**	1	1	**-**	*	-
Total consolidated	**129**	40	58	**30**	21	22
Equity affiliates						
Canada	**-**	-	-	**-**	-	-
Middle East and Africa	**-**	*	*	**-**	-	-
Russia and Caspian	**-**	-	-	**-**	1	-
Other areas	**-**	-	-	**-**	-	-
Total equity affiliates *(3)*	**-**	*	*	**-**	1	-
Includes step-out wells of:	***99***	*37*	*42*	***18***	*11*	*7*

		Productive			Dry	
	2007	2006	2005	**2007**	2006	2005
Development						
Consolidated operations						
Alaska	**46**	30	31	**-**	1	-
Lower 48	**686**	659	297	**7**	3	9
United States	**732**	689	328	**7**	4	9
Canada	**348**	675	425	**1**	8	2
Europe	**10**	10	19	**-**	-	-
Asia Pacific	**17**	15	17	**-**	-	-
Middle East and Africa	**7**	7	6	*****	-	-
Russia and Caspian	*****	*	-	**-**	-	-
Other areas	**5**	11	-	**-**	-	-
Total consolidated	**1,119**	1,407	795	**8**	12	11
Equity affiliates						
Canada	**70**	-	-	**1**	-	-
Middle East and Africa	**-**	-	-	**-**	-	-
Russia and Caspian	**2**	2	1	**-**	1	-

Other areas	**-**	15	28	**-**	-	1
Total equity affiliates *(3)*	**72**	17	29	**1**	1	1

(1) Excludes farmout arrangements.
(2) Includes step-out wells, as well as other types of exploratory wells. Step-out exploratory wells are wells drilled in areas near or offsetting current production, for which we cannot demonstrate with certainty that there is continuity of production from an existing productive formation. These are classified as exploratory wells because we cannot attribute proved reserves to these locations.
(3) Excludes LUKOIL.
**Our total proportionate interest was less than one.*

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Wells at Year-End 2007			Productive *(2)*			
	In Progress *(1)*		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
Consolidated operations						
Alaska	22	12	1,790	810	27	18
Lower 48	280	233	12,498	4,595	24,742	16,135
United States	302	245	14,288	5,405	24,769	16,153
Canada	147*(3)*	87*(3)*	1,648	913	10,773	6,412
Europe	59	11	556	99	344	118
Asia Pacific	168	79	335	124	95	58
Middle East and Africa	31	5	1,000	177	-	-
Russia and Caspian	25	2	-	-	-	-
Other areas	5	2	100	44	50	13
Total consolidated	737	431	17,927	6,762	36,031	22,754
Equity affiliates						
Canada	8	4	93	47	6	3
Russia and Caspian	28	9	69	25	-	-
Other areas	31	5	-	-	-	-
Total equity affiliates *(4)*	67	18	162	72	6	3

(1) Includes wells that have been temporarily suspended.

(2) Includes 5,479 gross and 3,450 net multiple completion wells.

(3) Includes 93 gross and 47 net stratigraphic test wells related to the Surmont heavy-oil project.

(4) Excludes LUKOIL.

Acreage at December 31, 2007 Thousands of Acres

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Consolidated operations				
Alaska	646	327	2,475	1,572
Lower 48	7,666	5,301	13,965	9,917
United States	8,312	5,628	16,440	11,489
Canada	7,002	4,328	14,074	9,292
Europe	1,373	342	4,454	1,429
Asia Pacific	4,214	1,818	28,367	18,588
Middle East and Africa	2,466	449	13,395	2,694
Russia and Caspian	-	-	1,379	128
Other areas	1,356	573	13,071	10,444
Total consolidated	24,723	13,138	91,180	54,064
Equity affiliates				
Canada	57	23	483	186
Middle East and Africa	-	-	76	11
Russia and Caspian	385	119	2,898	994
Other areas	-	-	-	-
Total equity affiliates*	442	142	3,457	1,191

**Excludes LUKOIL.*

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n **Costs Incurred**

	Millions of Dollars										
	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
2007											
Unproved property acquisition	$ 5	202	207	117	-	122	-	-	-	446	2,030
Proved property acquisition	-	42	42	-	-	-	2	-	-	44	1,729
	5	244	249	117	-	122	2	-	-	490	3,759
Exploration	115	468	583	196	235	147	73	37	21	1,292	78
Development	567	2,375	2,942	1,252	1,871	1,275	404	462	73	8,279	2,394
	$ 687	3,087	3,774	1,565	2,106	1,544	479	499	94	10,061	6,231
Costs incurred of equity affiliates	-	-	-	4,117	-	-	314	1,749	51	-	6,231
2006											
Unproved property acquisition	$ 4	860	864	554	113	-	30	-	39	1,600	143
Proved property acquisition	13	15,784	15,797	8,296	1,169	525	856	-	252	26,895	2,647
	17	16,644	16,661	8,850	1,282	525	886	-	291	28,495	2,790
Exploration	131	332	463	182	172	231	57	47	27	1,179	58
Development	629	1,733	2,362	1,926	1,653	919	249	371	141	7,621	1,326
	$ 777	18,709	19,486	10,958	3,107	1,675	1,192	418	459	37,295	4,174
Costs incurred of equity affiliates	$ -	-	-	-	-	-	183	3,854	137	-	4,174

2005											
Unproved property acquisition	$ 1	14	15	68	-	26	85	83	-	277	796
Proved property acquisition	16	767	783	-	-	6	569	125	-	1,483	1,763
	17	781	798	68	-	32	654	208	-	1,760	2,559
Exploration	64	74	138	163	117	204	67	37	11	737	60
Development	650	688	1,338	782	1,402	682	137	372	42	4,755	449
	$ 731	1,543	2,274	1,013	1,519	918	858	617	53	7,252	3,068
Costs incurred of equity affiliates	$ -	-	-	-	-	-	54	2,903	111	-	3,068

n Costs incurred include capitalized and expensed items.

n Acquisition costs include the costs of acquiring proved and unproved oil and gas properties. In 2007, equity affiliate acquisition costs were due to the EnCana business venture. In 2006 in our consolidated operations, acquisition costs were primarily related to the Burlington Resources acquisition.

n Exploration costs include geological and geophysical expenses, the cost of retaining undeveloped leaseholds, and exploratory drilling costs.

n Development costs include the cost of drilling and equipping development wells and building related production facilities for extracting, treating, gathering and storing petroleum liquids and natural gas.

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n **Capitalized Costs**

At December 31	Millions of Dollars										
	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
2007											
Proved properties	$ 10,182	28,645	38,827	17,330	20,615	8,014	2,758	2,135	641	90,320	12,491
Unproved properties	848	1,137	1,985	1,798	446	795	281	131	83	5,519	3,360
	11,030	29,782	40,812	19,128	21,061	8,809	3,039	2,266	724	95,839	15,851
Accumulated depreciation, depletion and amortization	4,158	7,920	12,078	4,875	9,374	2,155	822	4	504	29,812	1,008
	$ 6,872	21,862	28,734	14,253	11,687	6,654	2,217	2,262	220	66,027	14,843
Capitalized costs of equity affiliates	$ -	-	-	4,771	-	-	606	9,466	-	-	14,843
2006											
Proved properties	$ 9,567	26,227	35,794	14,455	17,773	6,870	2,577	1,669	633	79,771	11,550
Unproved properties	840	1,045	1,885	1,425	365	743	321	117	72	4,928	944
	10,407	27,272	37,679	15,880	18,138	7,613	2,898	1,786	705	84,699	12,494
Accumulated depreciation, depletion and amortization	3,573	5,525	9,098	2,795	7,450	1,581	737	3	81	21,745	933
	$ 6,834	21,747	28,581	13,085	10,688	6,032	2,161	1,783	624	62,954	11,561
Capitalized costs of equity affiliates	$ -	-	-	-	-	-	180	8,310	3,071	-	11,561

n 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, a Canadian Syncrude operation, crude oil and natural gas marketing activities, and downstream operations.

- Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves, development wells and related equipment and facilities (including uncompleted development well costs), and support equipment.
- Unproved properties include capitalized costs for oil and gas leaseholds under exploration (including where petroleum liquids and natural gas 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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n Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

Amounts are computed using year-end prices and costs (adjusted only for existing contractual changes), appropriate statutory tax rates and a prescribed 10 percent discount factor. Continuation of year-end economic conditions also is assumed. The calculation is based on estimates of proved reserves, which are revised over time as new data become available. Probable or possible reserves, which may become proved in the future, are not considered. The calculation also requires 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.

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Discounted Future Net Cash Flows

	Millions of Dollars										
	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
2007											
Future cash inflows	$ 133,909	94,706	228,615	30,125	83,367	46,520	31,509	11,272	803	432,211	163,555
Less:											
Future production and transportation costs*	75,024	41,945	116,969	11,206	15,781	11,996	3,884	1,876	706	162,418	97,375
Future development costs	8,392	9,690	18,082	4,605	10,920	3,958	400	2,761	34	40,760	10,847
Future income tax provisions	18,798	14,793	33,591	2,235	37,645	12,331	22,599	1,680	10	110,091	12,381
Future net cash flows	31,695	28,278	59,973	12,079	19,021	18,235	4,626	4,955	53	118,942	42,952
10 percent annual discount	16,510	12,158	28,668	3,870	5,776	7,113	1,847	4,504	2	51,780	22,925
Discounted future net cash flows	$ 15,185	16,120	31,305	8,209	13,245	11,122	2,779	451	51	67,162	20,027
Discounted future net cash flows of equity affiliates	$ -	-	-	3,889	-	-	4,453	11,685	-	-	20,027
2006											
Future cash inflows	$ 86,843	75,039	161,882	25,363	60,118	32,420	19,369	6,853	1,777	307,782	117,860
Less:											
Future production and transportation	43,393	23,096	66,489	9,393	13,186	6,730	4,308	1,692	1,082	102,880	66,929

costs*												
Future development costs		5,142	7,274	12,416	4,154	7,865	2,886	586	2,787	220	30,914	6,369
Future income tax provisions		14,138	14,357	28,495	2,313	25,627	9,204	12,029	590	101	78,359	16,085
Future net cash flows		24,170	30,312	54,482	9,503	13,440	13,600	2,446	1,784	374	95,629	28,477
10 percent annual discount		12,479	15,697	28,176	3,297	4,052	5,482	753	2,213	66	44,039	16,044
Discounted future net cash flows	$	11,691	14,615	26,306	6,206	9,388	8,118	1,693	(429)	308	51,590	12,433
Discounted future net cash flows of equity affiliates	$	-	-	-	-	-	-	1,703	5,441	5,289	-	12,433
2005												
Future cash inflows	$	96,574	48,560	145,134	11,907	74,790	31,310	19,337	11,069	787	294,334	111,825
Less:												
Future production and transportation costs*		34,586	10,425	45,011	2,892	12,055	5,343	3,442	2,410	488	71,641	47,634
Future development costs		4,569	1,686	6,255	965	7,517	2,920	474	1,917	149	20,197	4,760
Future income tax provisions		20,421	12,831	33,252	2,349	37,208	9,653	13,882	2,163	80	98,587	17,052
Future net cash flows		36,998	23,618	60,616	5,701	18,010	13,394	1,539	4,579	70	103,909	42,379
10 percent annual discount		19,414	11,934	31,348	2,184	6,006	5,639	560	4,168	56	49,961	25,720
Discounted future net cash flows	$	17,584	11,684	29,268	3,517	12,004	7,755	979	411	14	53,948	16,659
Discounted future net cash	$	-	-	-	-	-	-	1,865	5,024	9,770	-	16,659

flows of
equity
affiliates

**Includes taxes other than income taxes.*

Excludes discounted future net cash flows from Canadian Syncrude of $4,484 million in 2007, $2,220 million in 2006 and $2,159 million in 2005.

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Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars					
	Consolidated Operations			Equity Affiliates		
	2007	2006	2005	**2007**	2006	2005
Discounted future net cash flows at the beginning of the year	**$ 51,590**	53,948	35,488	**12,433**	16,659	8,210
Changes during the year						
Revenues less production and transportation costs for the year*	**(24,441)**	(25,133)	(18,867)	**(3,288)**	(3,379)	(2,586)
Net change in prices, and production and transportation costs*	**49,447**	(18,928)	46,332	**10,082**	(5,582)	6,555
Extensions, discoveries and improved recovery, less estimated future costs	**6,985**	3,867	3,942	**2,188**	401	2,201
Development costs for the year	**7,289**	7,020	4,282	**2,346**	1,327	449
Changes in estimated future development costs	**(10,813)**	(6,195)	(3,261)	**(3,468)**	(1,291)	(142)
Purchases of reserves in place, less estimated future costs	**51**	24,203	6,610	**2,989**	1,945	2,361
Sales of reserves in place, less estimated future costs	**(1,347)**	(506)	(306)	**(9,619)**	2	(34)
Revisions of previous quantity estimates**	**(79)**	(7,028)	(175)	**3,855**	107	1,245
Accretion of discount	**8,561**	9,759	5,728	**1,809**	2,215	1,032
Net change in income taxes	**(20,081)**	10,583	(25,825)	**700**	29	(2,632)
Other	**-**	-	-	**-**	-	-
Total changes	**15,572**	(2,358)	18,460	**7,594**	(4,226)	8,449
Discounted future net cash flows at year end	**$ 67,162**	51,590	53,948	**20,027**	12,433	16,659

**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-the-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.

- 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 end-of-the-year sales prices, less future estimated costs, discounted at 10 percent.

- 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			
	Sales and Other Operating Revenues**	Income from Continuing Operations Before Income Taxes	Income Before Cumulative Effect of Changes in Accounting Principles	Net Income	Income Before Cumulative Effect of Changes in Accounting Principles Basic	Income Before Cumulative Effect of Changes in Accounting Principles Diluted	Net Income Basic	Net Income Diluted
2007								
First	**$ 41,320**	**6,066**	**3,546**	**3,546**	**2.15**	**2.12**	**2.15**	**2.12**
Second***	**47,370**	**3,518**	**301**	**301**	**.18**	**.18**	**.18**	**.18**
Third	**46,062**	**6,364**	**3,673**	**3,673**	**2.26**	**2.23**	**2.26**	**2.23**
Fourth	**52,685**	**7,324**	**4,371**	**4,371**	**2.75**	**2.71**	**2.75**	**2.71**
2006								
First	$ 46,906	5,797	3,291	3,291	2.38	2.34	2.38	2.34
Second	47,149	8,682	5,186	5,186	3.13	3.09	3.13	3.09
Third	48,076	7,937	3,876	3,876	2.35	2.31	2.35	2.31
Fourth	41,519	5,917	3,197	3,197	1.94	1.91	1.94	1.91

**Effective April 1, 2006, we adopted Emerging Issues Task Force Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty, and began including the impact of our acquisition of Burlington Resources in our results of operations. See Note 2 Changes in Accounting Principles and Note 5 Acquisition of Burlington Resources Inc., in the Notes to Consolidated Financial Statements; and Management s Discussion and Analysis of Financial Condition and Results of Operations, for information affecting the comparability of the data.*
***Includes excise taxes on petroleum products sales.*
****Includes non-cash impairment charge of $4,588 million before-tax, $4,512 million after-tax, for the expropriation of our Venezuelan oil interests.*

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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 non-guarantor subsidiaries of ConocoPhillips.

The consolidating adjustments necessary to present ConocoPhillips results on a consolidated basis.

In April 2006, 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.

This condensed consolidating financial information should be read in conjunction with the accompanying consolidated financial statements and notes.

Millions of Dollars
Year Ended December 31, 2007

Income Statement	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	$ -	120,687	-	-	-	66,750	-	187,437
Equity in earnings of affiliates	12,071	9,800	-	-	-	3,025	(19,809)	5,087
Other income	4	(199)	-	-	-	2,166	-	1,971
Intercompany revenues	149	3,014	117	83	51	18,407	(21,821)	-
Total Revenues and Other Income	12,224	133,302	117	83	51	90,348	(41,630)	194,495
Costs and Expenses								
Purchased crude oil, natural gas and products	-	103,516	-	-	-	38,880	(18,967)	123,429
Production and operating expenses	-	4,522	-	-	-	6,247	(86)	10,683
Selling, general and administrative expenses	17	1,407	-	-	-	943	(61)	2,306
Exploration expenses	-	111	-	-	-	896	-	1,007
Depreciation, depletion and amortization	-	1,476	-	-	-	6,822	-	8,298
Impairment expropriated assets	-	1,925	-	-	-	2,663	-	4,588
Impairments	-	(73)	-	-	-	515	-	442
Taxes other than income taxes	-	5,463	-	-	-	13,802	(275)	18,990
Accretion on discounted liabilities	-	55	-	-	-	286	-	341
Interest and debt expense	423	1,054	109	77	53	1,969	(2,432)	1,253
Foreign currency transaction (gains) losses	-	12	-	166	124	(503)	-	(201)
Minority interests	-	-	-	-	-	87	-	87
	440	119,468	109	243	177	72,607	(21,821)	171,223

Total Costs and Expenses								
Income from continuing operations before income taxes	11,784	13,834	8	(160)	(126)	17,741	(19,809)	23,272
Provision for income taxes	(107)	2,810	3	16	6	8,653	-	11,381
Income from continuing operations	11,891	11,024	5	(176)	(132)	9,088	(19,809)	11,891
Income (loss) from discontinued operations	-	-	-	-	-	-	-	-
Income before cumulative effect of changes in accounting principles	11,891	11,024	5	(176)	(132)	9,088	(19,809)	11,891
Cumulative effect of changes in accounting principles	-	-	-	-	-	-	-	-
Net Income (Loss)	$ 11,891	11,024	5	(176)	(132)	9,088	(19,809)	11,891

Millions of Dollars
Year Ended December 31, 2006

Income Statement	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	$ -	117,063	-	-	-	66,587	-	183,650
Equity in earnings of affiliates	15,798	11,136	-	-	-	3,608	(26,354)	4,188
Other income	-	337	-	-	-	348	-	685
Intercompany revenues	173	2,599	94	17	10	15,740	(18,633)	-
Total Revenues and Other Income	15,971	131,135	94	17	10	86,283	(44,987)	188,523
Costs and Expenses								
Purchased crude oil, natural gas and products	-	97,986	-	-	-	37,735	(16,822)	118,899
Production and operating expenses	-	4,720	-	-	-	5,782	(89)	10,413
Selling, general and administrative expenses	19	1,593	-	-	-	914	(50)	2,476
Exploration expenses	-	120	-	-	-	714	-	834
Depreciation, depletion and amortization	-	1,702	-	-	-	5,582	-	7,284
Impairments	-	410	-	-	-	273	-	683
Taxes other than income taxes	-	5,877	-	-	-	12,577	(267)	18,187
Accretion on discounted liabilities	-	58	-	-	-	223	-	281
Interest and debt expense	537	1,070	80	17	11	777	(1,405)	1,087
Foreign currency transaction (gains) losses	-	(2)	-	(39)	(37)	48	-	(30)
Minority interests	-	-	-	-	-	76	-	76

Total Costs and Expenses	556	113,534	80	(22)	(26)	64,701	(18,633)	160,190
Income from continuing operations before income taxes	15,415	17,601	14	39	36	21,582	(26,354)	28,333
Provision for income taxes	(135)	2,839	5	10	10	10,054	-	12,783
Income from continuing operations	15,550	14,762	9	29	26	11,528	(26,354)	15,550
Income (loss) from discontinued operations	-	-	-	-	-	-	-	-
Income before cumulative effect of changes in accounting principles	15,550	14,762	9	29	26	11,528	(26,354)	15,550
Cumulative effect of changes in accounting principles	-	-	-	-	-	-	-	-
Net Income	$ 15,550	14,762	9	29	26	11,528	(26,354)	15,550

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		Millions of Dollars Year Ended December 31, 2005			
Income Statement	ConocoPhillips	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income					
Sales and other operating revenues	$ -	121,718	57,724	-	179,442
Equity in earnings of affiliates	13,754	10,235	2,842	(23,374)	3,457
Other income (loss)	(25)	152	338	-	465
Intercompany revenues	30	2,250	9,925	(12,205)	-
Total Revenues and Other Income	13,759	134,355	70,829	(35,579)	183,364
Costs and Expenses					
Purchased crude oil, natural gas and products	-	103,307	32,665	(11,047)	124,925
Production and operating expenses	-	4,711	3,917	(66)	8,562
Selling, general and administrative expenses	16	1,436	818	(23)	2,247
Exploration expenses	-	84	577	-	661
Depreciation, depletion and amortization	-	1,473	2,780	-	4,253
Impairments	-	2	40	-	42
Taxes other than income taxes	-	6,065	12,533	(242)	18,356
Accretion on discounted liabilities	-	37	156	-	193
Interest and debt expense	135	833	356	(827)	497
Foreign currency transaction (gains) losses	-	(16)	64	-	48
Minority interests	-	-	33	-	33
Total Costs and Expenses	151	117,932	53,939	(12,205)	159,817
Income from continuing operations before income taxes	13,608	16,423	16,890	(23,374)	23,547
Provision for income taxes	(32)	2,669	7,270	-	9,907
Income from continuing operations	13,640	13,754	9,620	(23,374)	13,640
Loss from discontinued operations	(23)	(23)	(6)	29	(23)
Income before cumulative effect of changes in accounting principles	13,617	13,731	9,614	(23,345)	13,617
Cumulative effect of changes in accounting principles	(88)	(88)	(29)	117	(88)
Net Income	$ 13,529	13,643	9,585	(23,228)	13,529

	Millions of Dollars At December 31, 2007							
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	$ -	195	-	7	1	1,626	(373)	1,456
Accounts and notes receivable	40	12,421	15	12	4	19,548	(15,686)	16,354
Inventories	-	2,043	-	-	-	2,190	(10)	4,223
Prepaid expenses and other current assets	9	578	-	1	-	2,114	-	2,702
Total Current Assets	49	15,237	15	20	5	25,478	(16,069)	24,735
Investments, loans and long-term receivables*	86,942	57,936	1,700	1,470	997	18,972	(134,689)	33,328
Net properties, plants and equipment	-	17,677	-	-	-	71,317	9	89,003
Goodwill	-	12,746	-	-	-	16,590	-	29,336
Intangibles	-	808	-	-	-	88	-	896
Other assets	8	153	3	5	4	520	(234)	459
Total Assets	$ 86,999	104,557	1,718	1,495	1,006	132,965	(150,983)	177,757
Liabilities and Stockholders Equity								
Accounts payable	$ 6	18,792	-	10	4	15,108	(16,059)	17,861
Notes payable and long-term debt due within one year	1,000	309	-	-	-	89	-	1,398
Accrued income and other taxes	-	601	-	-	(1)	4,117	97	4,814
Employee benefit obligations	-	509	-	-	-	411	-	920

Other accruals	21	594	20	16	11	1,230	(3)	1,889
Total Current Liabilities	1,027	20,805	20	26	14	20,955	(15,965)	26,882
Long-term debt	3,402	5,694	1,699	1,250	848	7,396	-	20,289
Asset retirement obligations and accrued environmental costs	-	1,167	-	-	-	6,094	-	7,261
Joint venture acquisition obligation	-	-	-	-	-	6,294	-	6,294
Deferred income taxes	(3)	3,050	-	32	18	17,907	14	21,018
Employee benefit obligations	-	2,292	-	-	-	899	-	3,191
Other liabilities and deferred credits*	42	16,447	-	132	102	15,489	(29,546)	2,666
Total Liabilities	4,468	49,455	1,719	1,440	982	75,034	(45,497)	87,601
Minority interests	-	(19)	-	-	-	1,194	(2)	1,173
Retained earnings	43,988	23,952	(1)	(147)	(107)	20,738	(37,913)	50,510
Other stockholders equity	38,543	31,169	-	202	131	35,999	(67,571)	38,473
Total	$ 86,999	104,557	1,718	1,495	1,006	132,965	(150,983)	177,757

** Includes intercompany loans.*

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	Millions of Dollars At December 31, 2006							
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	$ -	116	-	-	1	1,042	(342)	817
Accounts and notes receivable	65	13,233	22	10	2	17,224	(16,450)	14,106
Inventories	-	2,906	-	-	-	2,247	-	5,153
Prepaid expenses and other current assets	11	895	-	10	7	4,067	-	4,990
Total Current Assets	76	17,150	22	20	10	24,580	(16,792)	25,066
Investments and long-term receivables*	86,292	58,530	2,000	1,241	841	28,372	(156,563)	20,713
Net properties, plants and equipment	-	19,072	-	-	-	67,122	7	86,201
Goodwill	-	15,226	-	-	-	16,262	-	31,488
Intangibles	-	852	-	-	-	99	-	951
Other assets	10	141	5	35	24	195	(48)	362
Total Assets	$ 86,378	110,971	2,027	1,296	875	136,630	(173,396)	164,781
Liabilities and Stockholders Equity								
Accounts payable	$ 68	16,641	-	5	3	14,367	(16,450)	14,634
Notes payable and long-term debt due within one year	3,431	525	-	-	-	87	-	4,043
Accrued income and other taxes	-	732	-	-	-	3,577	98	4,407
Employee benefit obligations	-	464	-	-	-	431	-	895
Other accruals	50	804	24	16	10	1,565	(17)	2,452

Total Current Liabilities	3,549	19,166	24	21	13	20,027	(16,369)	26,431
Long-term debt	6,521	6,036	1,999	1,250	848	6,437	-	23,091
Asset retirement obligations and accrued environmental costs	-	1,095	-	-	-	4,524	-	5,619
Deferred income taxes	(8)	2,969	-	16	10	17,086	1	20,074
Employee benefit obligations	-	2,379	-	-	-	1,288	-	3,667
Other liabilities and deferred credits*	29	28,306	-	-	-	22,300	(48,584)	2,051
Total Liabilities	10,091	59,951	2,023	1,287	871	71,662	(64,952)	80,933
Minority interests	-	(19)	-	-	-	1,221	-	1,202
Retained earnings	34,756	22,939	4	29	26	28,029	(44,491)	41,292
Other stockholders equity	41,531	28,100	-	(20)	(22)	35,718	(63,953)	41,354
Total	$ 86,378	110,971	2,027	1,296	875	136,630	(173,396)	164,781

** Includes intercompany loans.*

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Millions of Dollars
Year Ended December 31, 2007

Statement of Cash Flows	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities								
Net cash provided by continuing operations	$ 14,984	9,944	10	7	-	26,021	(26,416)	24,550
Net cash used in discontinued operations	-	-	-	-	-	-	-	-
Net Cash Provided by Operating Activities	14,984	9,944	10	7	-	26,021	(26,416)	24,550
Cash Flows From Investing Activities								
Acquisition of Burlington Resources Inc.	-	-	-	-	-	-	-	-
Capital expenditures and investments, including dry hole costs	-	(2,967)	-	-	-	(9,121)	297	(11,791)
Proceeds from asset dispositions	-	1,391	-	-	-	3,029	(848)	3,572
Long-term advances/loans to affiliates and other investments	-	(491)	-	-	-	(2,649)	2,458	(682)
Collection of advances/loans to affiliates	-	1,238	300	-	-	837	(2,286)	89
Other	1	83	-	-	-	166	-	250
Net cash provided by (used in) continuing operations	1	(746)	300	-	-	(7,738)	(379)	(8,562)
Net cash used in discontinued operations	-	-	-	-	-	-	-	-
Net Cash Provided by (Used in) Investing Activities	1	(746)	300	-	-	(7,738)	(379)	(8,562)
Cash Flows From Financing Activities								

Issuance of debt	(39)	2,179	-	-	-	1,253	(2,458)	935
Repayment of debt	(5,564)	(1,385)	(300)	-	-	(1,491)	2,286	(6,454)
Repurchase of company common stock	(7,001)	-	-	-	-	-	-	(7,001)
Issuance of company common stock	285	-	-	-	-	-	-	285
Dividends paid on common stock	(2,661)	(10,000)	(10)	-	-	(16,376)	26,386	(2,661)
Other	(5)	87	-	-	-	(1,076)	550	(444)
Net Cash Used in Financing Activities	(14,985)	(9,119)	(310)	-	-	(17,690)	26,764	(15,340)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	-	-	-	-	(9)	-	(9)
Net Change in Cash and Cash Equivalents	-	79	-	7	-	584	(31)	639
Cash and cash equivalents at beginning of year	-	116	-	-	1	1,042	(342)	817
Cash and Cash Equivalents at End of Year	$ -	195	-	7	1	1,626	(373)	1,456

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	Millions of Dollars							
	Year Ended December 31, 2006							
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 continuing operations	$ 29,520	6,723	4	6	8	7,659	(22,404)	21,516
Net cash used in discontinued operations	-	-	-	-	-	-	-	-
Net Cash Provided by Operating Activities	29,520	6,723	4	6	8	7,659	(22,404)	21,516
Cash Flows From Investing Activities								
Acquisition of Burlington Resources Inc.	-	-	-	-	-	(14,285)	-	(14,285)
Capital expenditures and investments, including dry hole costs	(17,494)	(3,538)	-	-	-	(12,696)	18,132	(15,596)
Proceeds from asset dispositions	-	73	-	-	-	472	-	545
Long-term advances/loans to affiliates and other investments	(14,989)	(290)	(1,992)	(1,250)	(1,711)	(3,896)	23,348	(780)
Collection of advances/loans to affiliates	-	2,708	-	-	861	4,384	(7,830)	123
Net cash used in continuing operations	(32,483)	(1,047)	(1,992)	(1,250)	(850)	(26,021)	33,650	(29,993)
Net cash used in discontinued operations	-	-	-	-	-	-	-	-
Net Cash Used in Investing Activities	(32,483)	(1,047)	(1,992)	(1,250)	(850)	(26,021)	33,650	(29,993)
Cash Flows From Financing Activities								
Issuance of debt	12,892	18,394	2,000	1,250	848	5,278	(23,348)	17,314
Repayment of debt	(6,936)	(4,536)	-	-	-	(3,440)	7,830	(7,082)

Repurchase of company common stock		(925)	-	-	-	-	-	-	(925)
Issuance of company common stock		220	-	-	-	-	-	-	220
Dividends paid on common stock		(2,277)	(20,000)	(5)	-	-	(2,056)	22,061	(2,277)
Other		(11)	(31)	(7)	(6)	(5)	18,006	(18,131)	(185)
Net Cash Provided by (Used in) Financing Activities		2,963	(6,173)	1,988	1,244	843	17,788	(11,588)	7,065
Effect of Exchange Rate Changes on Cash and Cash Equivalents		-	-	-	-	-	15	-	15
Net Change in Cash and Cash Equivalents		-	(497)	-	-	1	(559)	(342)	(1,397)
Cash and cash equivalents at beginning of year		-	613	-	-	-	1,601	-	2,214
Cash and Cash Equivalents at End of Year	$	-	116	-	-	1	1,042	(342)	817

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Statement of Cash Flows	ConocoPhillips	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars Year Ended December 31, 2005				
Cash Flows From Operating Activities					
Net cash provided by continuing operations	$ 183	15,956	11,192	(9,698)	17,633
Net cash provided by (used in) discontinued operations	-	(7)	2	-	(5)
Net Cash Provided by Operating Activities	183	15,949	11,194	(9,698)	17,628
Cash Flows From Investing Activities					
Capital expenditures and investments, including dry hole costs	-	(5,118)	(9,119)	2,617	(11,620)
Proceeds from asset dispositions	-	279	491	(2)	768
Long-term advances/loans to affiliates and other	-	(20,056)	(1,208)	20,989	(275)
Collection of advances/loans to affiliates and other	1,240	12,339	2,161	(15,629)	111
Net cash provided by (used in) continuing operations	1,240	(12,556)	(7,675)	7,975	(11,016)
Net cash used in discontinued operations	-	-	-	-	-
Net Cash Provided by (Used in) Investing Activities	1,240	(12,556)	(7,675)	7,975	(11,016)
Cash Flows From Financing Activities					
Issuance of debt	2,901	1,504	17,036	(20,989)	452
Repayment of debt	(1,160)	(5,115)	(12,356)	15,629	(3,002)
Repurchase of company common stock	(1,924)	-	-	-	(1,924)
Issuance of company common stock	402	-	-	-	402
Dividends paid on common stock	(1,639)	-	(9,700)	9,700	(1,639)
Other	(3)	(50)	2,697	(2,617)	27
Net Cash Used in Financing Activities	(1,423)	(3,661)	(2,323)	1,723	(5,684)

Effect of Exchange Rate Changes on Cash and Cash Equivalents		-	2	(103)	-	(101)
Net Change in Cash and Cash Equivalents		-	(266)	1,093	-	827
Cash and cash equivalents at beginning of year		-	879	508	-	1,387
Cash and Cash Equivalents at End of Year	$	-	613	1,601	-	2,214

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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, 2007, with the participation of our management, our Chairman, President and Chief Executive Officer (principal executive officer) and our Executive 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, President and Chief Executive Officer and our Executive Vice President, Finance, and Chief Financial Officer concluded that our disclosure controls and procedures were operating effectively as of December 31, 2007.

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, 2007, 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 99 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 pages 101 and 102 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 43 and 44.

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* (accessed through the About ConocoPhillips link on the home page). 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 2008 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2008, 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 2008 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2008, 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 2008 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2008, 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 2008 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2008, 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 2008 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2008, 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 the 2008 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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PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements and Financial Statement Schedules

The financial statements and schedule listed in the Index to Financial Statements and Financial Statement Schedules, which appears on page 98, are filed as part of this annual report.

2. Exhibits

The exhibits listed in the Index to Exhibits, which appears on pages 208 through 211, are filed as a part of this annual report.

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CONOCOPHILLIPS
(Consolidated)
SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

	Millions of Dollars				
		Additions			
Description	Balance At January 1	Charged to Expense	Other(a)	Deductions	Balance At December 31
2007					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	**$ 45**	**23**	**(2)**	**(8)(b)**	**58**
Deferred tax asset valuation allowance	**822**	**67**	**417**	**(37)**	**1,269**
Included in other liabilities:					
Restructuring accruals	**164**	**31**	**5**	**(83)(c)**	**117**
2006					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 72	11	9	(47)(b)	45
Deferred tax asset valuation allowance	850	103	42	(173)	822
Included in other liabilities:					
Restructuring accruals	53	10	216	(115)(c)	164
2005					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 55	21	4	(8)(b)	72
Deferred tax asset valuation allowance	968	90	(26)	(182)	850
Included in other liabilities:					
Restructuring accruals	89	(2)	(3)	(31)(c)	53

(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.

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CONOCOPHILLIPS
INDEX TO EXHIBITS

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of November 18, 2001, by and among ConocoPhillips Company (formerly named Phillips Petroleum Company), ConocoPhillips (formerly named CorvettePorsche Corp.), P Merger Corp. (formerly named Porsche Merger Corp.), C Merger Corp. (formerly named Corvette Merger Corp.) and ConocoPhillips Holding Company (formerly named Conoco Inc.) (Holding) (incorporated by reference to Annex A to the Joint Proxy Statement/Prospectus included in ConocoPhillips Registration Statement on Form S-4; Registration No. 333-74798 (the Form S-4)).
2.2	Agreement and Plan of Merger, dated as of December 12, 2005, by and among ConocoPhillips, Cello Acquisition Corp. and Burlington Resources Inc. (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips on Form 8-K filed on December 14, 2005; File No. 001-32395).
3.1	Restated Certificate of Incorporation of ConocoPhillips (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987 (the Form 8-K)).
3.2	Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips (incorporated by reference to Exhibit 3.2 to the Form 8-K).
3.3	By-Laws of ConocoPhillips, as amended on February 15, 2008 (incorporated by reference to Exhibit 99.1 to the Current Report of ConocoPhillips on Form 8-K filed on February 19, 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 Form 8-K).
	ConocoPhillips and its subsidiaries are parties to several debt instruments under which the total amount of securities authorized does not exceed 10 percent of the total assets of ConocoPhillips and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, ConocoPhillips agrees to furnish a copy of such instruments to the SEC upon request.
10.1	Shareholder Agreement, dated September 29, 2004, by and between LUKOIL and ConocoPhillips (incorporated by reference to Exhibit 99.2 of the Current Report of ConocoPhillips on Form 8-K filed on September 30, 2004; File No. 333-74798).
10.2	1986 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).

Exhibit Number	Description
10.3	1990 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.4	Annual Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.5	Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(g) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1999; File No. 1-720).
10.6	Principal Corporate Officers Supplemental Retirement Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(h) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1995; File No. 1-720).
10.7	ConocoPhillips Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.8	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).
10.9	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).
10.10	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).
10.11	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).
10.12	ConocoPhillips Key Employee Supplemental Retirement Plan (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.13.1	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).
10.13.2	Defined Contribution Make-Up Plan of ConocoPhillips Title II (incorporated by reference to Exhibit 10.13.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31,

2005; File No. 001-32395).

Exhibit Number	Description
10.14	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).
10.15	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).
10.16	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).
10.17	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).
10.18	ConocoPhillips Form Indemnity Agreement with Directors (incorporated by reference to Exhibit 10.34 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.19	Letter Agreement, dated as of April 12, 2002, between Holding and Jim W. Nokes (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended September 30, 2002; File No. 000-49987).
10.20	Rabbi Trust Agreement dated December 17, 1999 (incorporated by reference to Exhibit 10.11 of Holding s Form 10-K for the year ended December 31, 1999, File No. 001-14521).
10.20.1	Amendment to Rabbi Trust Agreement dated February 25, 2002 (incorporated by reference to Exhibit 10.39.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.21	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).
10.22	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).
10.23.1	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).
10.23.2	Key Employee Deferred Compensation Plan of ConocoPhillips Title II (incorporated by reference to Exhibit 10.23.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31,

2005; File No. 001-32395).

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Exhibit Number	Description
10.24	ConocoPhillips Key Employee Change in Control Severance Plan (incorporated by reference to Exhibit 10.1 of the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended September 30, 2004; File No. 000-49987).
10.25	ConocoPhillips Executive Severance Plan (incorporated by reference to Exhibit 10.25 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.25.1	First and Second Amendments to the ConocoPhillips Executive Severance Plan (incorporated by reference to Exhibit 10 of the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended March 31, 2007; File No. 001-32395).
10.26	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).
10.27	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).
10.28	Form of Stock Option Award Agreement under the ConocoPhillips Stock Option and Stock Appreciation Rights Program.
10.29	Form of Restricted Stock Unit Award Agreement under the ConocoPhillips Performance Share Program.
10.30	Omnibus Amendments to certain ConocoPhillips employee benefit plans, adopted December 7, 2007.
12	Computation of Ratio of Earnings to Fixed Charges.
21	List of Subsidiaries of ConocoPhillips.
23	Consent of Independent Registered Public Accounting Firm.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32	Certifications pursuant to 18 U.S.C. Section 1350.

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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 21, 2008

/s/ James J. Mulva
James J. Mulva
Chairman of the Board of Directors,
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 21, 2008, 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, President and Chief Executive Officer (Principal executive officer)
/s/ John A. Carrig *John A. Carrig*	Executive Vice President, Finance, and Chief Financial Officer (Principal financial officer)
/s/ Rand C. Berney *Rand C. Berney*	Vice President and Controller (Principal accounting officer)

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/s/ Richard L. Armitage *Richard L. Armitage*	Director
/s/ Richard H. Auchinleck *Richard H. Auchinleck*	Director
/s/ Norman R. Augustine *Norman R. Augustine*	Director
/s/ James E. Copeland, Jr. *James E. Copeland, Jr.*	Director
/s/ Kenneth M. Duberstein *Kenneth M. Duberstein*	Director
/s/ Ruth R. Harkin *Ruth R. Harkin*	Director
/s/ Charles C. Krulak *Charles C. Krulak*	Director
/s/ Harold W. McGraw, III *Harold W. McGraw, III*	Director
/s/ Harald J. Norvik *Harald J. Norvik*	Director
/s/ William K. Reilly	Director

William K. Reilly	
/s/ William R. Rhodes	Director
William R. Rhodes	
/s/ J. Stapleton Roy	Director
J. Stapleton Roy	
/s/ Bobby S. Shackouls	Director
Bobby S. Shackouls	

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/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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CONOCOPHILLIPS
INDEX TO EXHIBITS

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of November 18, 2001, by and among ConocoPhillips Company (formerly named Phillips Petroleum Company), ConocoPhillips (formerly named CorvettePorsche Corp.), P Merger Corp. (formerly named Porsche Merger Corp.), C Merger Corp. (formerly named Corvette Merger Corp.) and ConocoPhillips Holding Company (formerly named Conoco Inc.) (Holding) (incorporated by reference to Annex A to the Joint Proxy Statement/Prospectus included in ConocoPhillips Registration Statement on Form S-4; Registration No. 333-74798 (the Form S-4)).
2.2	Agreement and Plan of Merger, dated as of December 12, 2005, by and among ConocoPhillips, Cello Acquisition Corp. and Burlington Resources Inc. (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips on Form 8-K filed on December 14, 2005; File No. 001-32395).
3.1	Restated Certificate of Incorporation of ConocoPhillips (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987 (the Form 8-K)).
3.2	Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips (incorporated by reference to Exhibit 3.2 to the Form 8-K).
3.3	By-Laws of ConocoPhillips, as amended on February 15, 2008 (incorporated by reference to Exhibit 99.1 to the Current Report of ConocoPhillips on Form 8-K filed on February 19, 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 Form 8-K).
	ConocoPhillips and its subsidiaries are parties to several debt instruments under which the total amount of securities authorized does not exceed 10 percent of the total assets of ConocoPhillips and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, ConocoPhillips agrees to furnish a copy of such instruments to the SEC upon request.
10.1	Shareholder Agreement, dated September 29, 2004, by and between LUKOIL and ConocoPhillips (incorporated by reference to Exhibit 99.2 of the Current Report of ConocoPhillips on Form 8-K filed on September 30, 2004; File No. 333-74798).
10.2	1986 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).

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Exhibit Number	Description
10.3	1990 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.4	Annual Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.5	Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(g) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1999; File No. 1-720).
10.6	Principal Corporate Officers Supplemental Retirement Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(h) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1995; File No. 1-720).
10.7	ConocoPhillips Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.8	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).
10.9	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).
10.10	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).
10.11	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).
10.12	ConocoPhillips Key Employee Supplemental Retirement Plan (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.13.1	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).
10.13.2	Defined Contribution Make-Up Plan of ConocoPhillips Title II (incorporated by reference to Exhibit 10.13.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31,

2005; File No. 001-32395).

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Exhibit Number	Description
10.14	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).
10.15	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).
10.16	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).
10.17	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).
10.18	ConocoPhillips Form Indemnity Agreement with Directors (incorporated by reference to Exhibit 10.34 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.19	Letter Agreement, dated as of April 12, 2002, between Holding and Jim W. Nokes (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended September 30, 2002; File No. 000-49987).
10.20	Rabbi Trust Agreement dated December 17, 1999 (incorporated by reference to Exhibit 10.11 of Holding s Form 10-K for the year ended December 31, 1999, File No. 001-14521).
10.20.1	Amendment to Rabbi Trust Agreement dated February 25, 2002 (incorporated by reference to Exhibit 10.39.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.21	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).
10.22	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).
10.23.1	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).
10.23.2	Key Employee Deferred Compensation Plan of ConocoPhillips Title II (incorporated by reference to Exhibit 10.23.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31,

2005; File No. 001-32395).

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Exhibit Number	Description
10.24	ConocoPhillips Key Employee Change in Control Severance Plan (incorporated by reference to Exhibit 10.1 of the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended September 30, 2004; File No. 000-49987).
10.25	ConocoPhillips Executive Severance Plan (incorporated by reference to Exhibit 10.25 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.25.1	First and Second Amendments to the ConocoPhillips Executive Severance Plan (incorporated by reference to Exhibit 10 of the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended March 31, 2007; File No. 001-32395).
10.26	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).
10.27	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).
10.28	Form of Stock Option Award Agreement under the ConocoPhillips Stock Option and Stock Appreciation Rights Program.
10.29	Form of Restricted Stock Unit Award Agreement under the ConocoPhillips Performance Share Program.
10.30	Omnibus Amendments to certain ConocoPhillips employee benefit plans, adopted December 7, 2007.
12	Computation of Ratio of Earnings to Fixed Charges.
21	List of Subsidiaries of ConocoPhillips.
23	Consent of Independent Registered Public Accounting Firm.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32	Certifications pursuant to 18 U.S.C. Section 1350.