CONOCOPHILLIPS
Form 10-K
February 19, 2013
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2012

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, 2012**

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ____________________ to ____________________

Commission file number: **001-32395**

ConocoPhillips

(Exact name of registrant as specified in its charter)

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

600 North Dairy Ashford

Houston, TX 77079

(Address of principal executive offices) (Zip Code)

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

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

Title of each class	Name of each exchange on which registered
Common Stock, $.01 Par Value	New York Stock Exchange
6.65% Debentures due July 15, 2018	New York Stock Exchange
7% Debentures due 2029	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

[x] Yes [ ] No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

[ ] Yes [x] No

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

[x] Yes [ ] No

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

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

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

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

The aggregate market value of common stock held by non-affiliates of the registrant on June 30, 2012, the last business day of the registrant s most recently completed second fiscal quarter, based on the closing price on that date of $55.88, was $67.9 billion. The registrant, solely for the purpose of this required presentation, had deemed its Board of Directors to be an affiliate and deducted their stockholdings of 66,914 shares in determining the aggregate market value.

The registrant had 1,220,992,874 shares of common stock outstanding at January 31, 2013.

Documents incorporated by reference:

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 14, 2013 (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 its consolidated subsidiaries. Items 1 and 2 Business and Properties, contain forward-looking statements including, without limitation, statements relating to our plans, strategies, objectives, expectations and intentions that are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The words anticipate, estimate, believe, budget, continue, could, intend, may, plan, p seek, should, will, would, expect, objective, projection, forecast, goal, guidance, outlook, effort, target and similar ex forward-looking statements. The company does not undertake to update, revise or correct any forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company s disclosures under the heading CAUTIONARY STATEMENT FOR THE PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995, beginning on page 67.

Items 1 and 2. BUSINESS AND PROPERTIES

CORPORATE STRUCTURE

ConocoPhillips is the world s largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. ConocoPhillips was incorporated in the state of Delaware on November 16, 2001, in connection with, and in anticipation of, the merger between Conoco Inc. and Phillips Petroleum Company. The merger between Conoco and Phillips was consummated on August 30, 2002.

On April 30, 2012, we completed the separation of our downstream businesses into an independent, publicly traded company, Phillips 66. Our refining, marketing and transportation businesses, most of our Midstream segment, our Chemicals segment, as well as our power generation and certain technology operations included in our Emerging Businesses segment (collectively, our Downstream business), were transferred to Phillips 66. As a part of our strategic asset disposition program, in the fourth quarter of 2012, we agreed to sell our interest in the North Caspian Sea Production Sharing Agreement (Kashagan) and our Nigerian and Algerian businesses. Results of operations related to Phillips 66, Kashagan, Nigeria and Algeria have been classified as discontinued operations in all periods presented in this Annual Report on Form 10-K. For additional information, see Note 2 Discontinued Operations, in the Notes to Consolidated Financial Statements.

Headquartered in Houston, Texas, we have operations and activities in 30 countries. Our key focus areas include safely operating producing assets, executing major developments and exploring for new resources in promising areas. Our portfolio primarily includes legacy assets in North America, Europe, Asia and Australia; growing North American shale and oil sands businesses; several major international developments; and a global exploration program.

At December 31, 2012, ConocoPhillips employed approximately 16,900 people worldwide.

SEGMENT AND GEOGRAPHIC INFORMATION

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

We explore for, produce, transport and market crude oil, bitumen, natural gas, liquefied natural gas (LNG) and natural gas liquids on a worldwide basis. At December 31, 2012, our continuing operations were producing in

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the United States, Norway, the United Kingdom, Canada, Australia, offshore Timor-Leste in the Timor Sea, Indonesia, China, Malaysia, Qatar, Libya and Russia.

Our operating segments were realigned upon the separation of Phillips 66, and as a result, all prior periods presented have been restated. We manage our operations through six operating segments, which are defined by geographic region: Alaska, Lower 48 and Latin America, Canada, Europe, Asia Pacific and Middle East, and Other International.

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

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

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The following table is a summary of the proved reserves information included in the Oil and Gas Operations disclosures following the Notes to Consolidated Financial Statements. Approximately 80 percent of our proved reserves are located in politically stable countries that belong to the Organization for Economic Cooperation and Development. Natural gas reserves are converted to BOE based on a 6:1 ratio: six thousand cubic feet of natural gas converts to one BOE. See Management s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that will enhance the understanding of the table below.

	Millions of Barrels of Oil Equivalent		
Net Proved Reserves at December 31	**2012**	2011	2010
Crude oil			
Consolidated operations	**2,684**	2,617	2,496
Equity affiliates	**95**	124	177
Total Crude Oil	**2,779**	2,741	2,673
Natural gas liquids			
Consolidated operations	**646**	670	665
Equity affiliates	**48**	51	54
Total Natural Gas Liquids	**694**	721	719
Natural gas			
Consolidated operations	**2,726**	2,933	3,039
Equity affiliates	**543**	553	580
Total Natural Gas	**3,269**	3,486	3,619
Bitumen			
Consolidated operations	**506**	530	455
Equity affiliates	**1,394**	909	844
Total Bitumen	**1,900**	1,439	1,299
Total consolidated operations	**6,562**	6,750	6,655
Total equity affiliates	**2,080**	1,637	1,655
Total company	**8,642**	8,387	8,310

In 2012, worldwide production, including our share of equity affiliates, was 1,578 thousand barrels of oil equivalent per day (MBOED), a 3 percent decrease from 2011 production of 1,619 MBOED. Production from continuing operations for 2012 averaged 1,527 MBOED, compared with 1,561 MBOED in 2011. Average production from continuing operations decreased 2 percent in 2012, primarily as a result of normal field decline, the impact from asset dispositions and higher planned and unplanned downtime. These decreases were largely offset by additional production from major developments, mainly from shale plays in the Lower 48 and ramp-up of new phases at FCCL, the resumption of production in Libya following a period of civil unrest in 2011, and increased drilling programs in the Lower 48.

Our worldwide annual average crude oil sales price from continuing operations remained relatively flat in 2012, from $105.52 per barrel in 2011 to $105.72 per barrel in 2012, while worldwide average annual natural gas liquids prices from continuing operations decreased 17 percent, from $55.73 per barrel in 2011 to $46.36 per barrel in 2012. Our average annual worldwide natural gas sales price from continuing operations decreased 6 percent, from $5.80 per thousand cubic feet in 2011 to $5.48 per thousand cubic feet in 2012. Average annual bitumen prices decreased 14 percent, from $62.56 per barrel in 2011 to $53.91 per barrel in 2012.

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ALASKA

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids, natural gas and LNG. In 2012, Alaska operations contributed 24 percent of our worldwide liquids production and 1 percent of our natural gas production.

				2012	
	Interest	Operator	Liquids MBD(1)	Natural Gas MMCFD(2)	Total MBOED
Average Daily Net Production					
Greater Prudhoe Area	36.1%	BP	104	5	105
Greater Kuparuk Area	52.2-55.4	ConocoPhillips	54	-	54
Western North Slope	78	ConocoPhillips	46	1	46
Cook Inlet Area	33.3-100	ConocoPhillips	-	49	8
Total Alaska			204	55	213

(1) Thousands of barrels per day.

(2) Millions of cubic feet per day.

Greater Prudhoe Area

The Greater Prudhoe Area includes the Prudhoe Bay Field and five satellite fields, as well as the Greater Point McIntyre Area fields. Prudhoe Bay, the largest oil field on Alaska s North Slope, is the site of a large waterflood and enhanced oil recovery operation, as well as a gas processing plant which processes natural gas for reinjection into the reservoir. Prudhoe Bay s satellites are Aurora, Borealis, Polaris, Midnight Sun and Orion, while the Point McIntyre, Niakuk, Raven and Lisburne fields are part of the Greater Point McIntyre Area.

Greater Kuparuk Area

We operate the Greater Kuparuk Area, which is made up of the Kuparuk Field and four satellite fields: Tarn, Tabasco, Meltwater and West Sak. Kuparuk is located 40 miles west of Prudhoe Bay on Alaska s North Slope. Field installations include three central production facilities that separate oil, natural gas and water, as well as a separate seawater treatment plant. The natural gas is either used for fuel or compressed for reinjection.

Western North Slope

On the Western North Slope, we operate the Colville River Unit, which includes the Alpine Field and three satellite fields: Nanuq, Fiord and Qannik. Alpine is located 34 miles west of Kuparuk. In October 2012, Alpine West CD5, a satellite field located west of Alpine in the National Petroleum Reserve Alaska (NPRA), was sanctioned. Initial production is anticipated in late 2015, with net peak production estimated at 10 MBOED in 2016.

Cook Inlet Area

We operate the North Cook Inlet Unit, the Beluga River Unit, and the Kenai LNG Plant in the Cook Inlet Area. We have a 100 percent interest in the North Cook Inlet Unit and the Kenai LNG Plant, while we own 33.3 percent of the Beluga River Unit. Our share of production is sold to local utilities and is also used to supply feedstock and fuel to the Kenai LNG Plant.

The Kenai LNG Plant had historically supplied LNG to utility companies in Japan. Although we idled the plant in October 2012, we maintain the capability to operate it and are evaluating options for future use. The LNG export license will expire in March 2013.

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Point Thomson

We own a 5 percent interest in the Point Thomson Field, which is located approximately 60 miles east of Prudhoe Bay. An initial production system is anticipated to be online by 2016, which is estimated to send 400 net BOED of condensate through the Trans-Alaska Pipeline System (TAPS).

North Slope Natural Gas

In March 2012, we, along with Exxon Mobil Corporation, BP p.l.c. and TransCanada Corporation, announced we are working together on a plan aimed at commercializing North Slope natural gas resources through large-scale LNG exports from south-central Alaska. Planning and assessment is ongoing.

Exploration

In the February 2008 Outer Continental Shelf (OCS) Lease Sale 193, we successfully bid and were awarded 10-year-primary-term leases on 98 blocks in the Chukchi Sea. We plan to drill an exploration well on our Devil s Paw prospect in 2014, subject to the outcome of pending litigation challenging Lease Sale 193 and the receipt of required regulatory permits.

Shark Tooth #1, an appraisal step-out well from the southwestern area of the Kuparuk Field, was spud in January 2012, and is being evaluated for further development potential. During 2013, we plan to drill one exploration well, Cassin, on the North Slope.

Transportation

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

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

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LOWER 48 AND LATIN AMERICA

Lower 48

The Lower 48 and Latin America segment primarily consists of operations located in the U.S. Lower 48 states. We hold 15.5 million net onshore and offshore acres in the Lower 48. In 2012, Lower 48 and Latin America contributed 25 percent of our worldwide liquids production and 37 percent of our natural gas production.

			2012		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Eagle Ford	Various %	Various	56	85	70
Bakken	Various	Various	22	17	25
Barnett	Various	Various	6	49	14
Permian	Various	Various	33	111	51
San Juan	Various	Various	49	750	174
Lobo	Various	ConocoPhillips	5	112	24
Anadarko Basin	Various	Various	6	124	27
Wind River	Various	Various	-	78	13
Bossier	Various	Various	-	43	7
Other onshore	Various	Various	18	111	37
Gulf of Mexico	Various	Various	13	13	15
Total U.S. Lower 48			208	1,493	457

Onshore

We hold 13.8 million net acres of onshore conventional and unconventional acreage in the Lower 48. Our unconventional holdings total 2.5 million net acres and include approximately 626,000 net acres in the Bakken; 227,000 net acres in the Eagle Ford; 194,000 net acres in Permian; 130,000 net acres in Niobrara; 900,000 net acres in the San Juan Basin; and nearly 430,000 net acres in other unconventional exploration plays. The majority of this acreage is either held by production or owned by the Company.

The majority of our 2012 onshore production originated from the San Juan Basin, Permian Basin, Eagle Ford, Bakken, Barnett, the Lobo Trend, Anadarko Basin and Bossier Trend. We also have operations in the Wind River Basin, East Texas, Rockies and northern and southern Louisiana. Onshore activities in 2012 were centered mostly on continued optimization and development of existing and emerging assets, with particular focus on areas with higher liquids production.

Shale Plays

Exploration and development continued in our shale positions in the Eagle Ford, Bakken and Barnett. In the Eagle Ford, we drilled 211 exploration and development wells and connected 170 wells in 2012, achieving net peak production of over 100 MBOED in December 2012. In 2013, we plan to drill approximately 140 wells and connect approximately 200 wells. With continued investments, we expect long-term average production from the Eagle Ford will be approximately 140 MBOED by 2016.

San Juan

The San Juan Basin, located in northwestern New Mexico and southwestern Colorado, includes significant conventional gas production, which yields approximately 35 percent natural gas liquids, as well as the majority of our U.S. coalbed methane (CBM) production. We hold approximately 1.3 million acres of oil and gas leases by production in San Juan, where we continue to pursue

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conventional development opportunities. This includes approximately 900,000 net acres of lease rights, where we are advancing the assessment of the Mancos shale play.

In January 2013, we entered into an agreement to sell the majority of our properties in the Cedar Creek Anticline, comprising approximately 86,000 net acres in southwestern North Dakota and eastern Montana. The transaction is expected to close in the first quarter of 2013.

Gulf of Mexico

At year-end 2012, our portfolio of producing properties in the Gulf of Mexico primarily consisted of one operated field and three fields operated by co-venturers, including:

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

Exploration

Conventional Exploration

In the deepwater Gulf of Mexico, we held 1.7 million acres at December 31, 2012. In November 2012, we were the successful high bidder on 62 blocks in OCS Western Lease Sale 229, the majority of which have been awarded to date. We anticipate the remaining blocks will be awarded in the first quarter of 2013, which would increase our Gulf of Mexico position to 2.0 million net acres. In 2013, drilling continued on the partner-operated Coronado wildcat well and the Shenandoah appraisal well, both of which were spud in 2012. During the first half of 2013, drilling is expected to commence on the partner-operated Ardennes wildcat well, the Tiber appraisal well and a ConocoPhillips-operated wildcat well in the Miocene/Pliocene Thorn prospect. We also plan to participate in two-to-three additional non-operated wildcat wells in 2013.

In support of our intentions to grow our Gulf of Mexico exploration program, we secured access to an ultra deepwater drillship in 2012, which will provide rig availability for our operated drilling program beginning in 2014.

Unconventional Exploration

In 2012, we actively pursued the appraisal of our existing unconventional resource plays, including the Eagle Ford in South Texas, the Bakken in the Williston Basin, the Barnett in the Fort Worth Basin, the Niobrara play in the Denver-Julesburg Basin, the Avalon and Wolfcamp in the Permian Basin, and the Mancos in the San Juan Basin. During 2012, we acquired approximately 340,000 net additional acres in various resource plays across the Lower 48, which included the Avalon, Wolfcamp, Niobrara, and various exploration plays, further expanding our significant acreage position in Lower 48 shale plays to approximately 2.5 million net acres.

During 2012, we drilled a total of 20 unconventional test wells in the Avalon, Wolfcamp, Niobrara, Bakken Little Missouri, Lewis and Mancos plays. Drilling is expected to continue in 2013.

Transportation

Our 25 percent interest in the Rockies Express Pipeline (REX) was transferred to Phillips 66 as part of the separation. We retained the capacity rights and obligations to REX.

Facilities

Freeport LNG Terminal

We have a long-term agreement with Freeport LNG Development, L.P. to use 0.9 billion cubic feet per day of regasification capacity at Freeport s 1.5-billion-cubic-feet-per-day LNG receiving terminal in Quintana, Texas.

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Market conditions currently favor the flow of LNG to European and Asian markets; therefore, our near- to mid-term utilization of the Freeport Terminal is expected to be limited to LNG storage and reload activities. We are responsible for monthly process-or-pay payments to Freeport irrespective of whether we utilize the terminal for regasification. The financial impact of these capacity underutilization payments is not expected to be material to our future earnings or cash flows.

Golden Pass LNG Terminal

We have a 12.4 percent ownership interest in the Golden Pass LNG Terminal and affiliated Golden Pass Pipeline. It is located adjacent to the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. The terminal became commercially operational in May 2011. We hold terminal and pipeline capacity for the receipt, storage and regasification of the LNG purchased from Qatargas 3 and the transportation of regasified LNG to interconnect with major interstate natural gas pipelines. Market conditions currently favor the flow of LNG to European and Asian markets; therefore, our near-to-mid-term utilization of the terminal is expected to be limited.

Phoenix Park Gas Processors Limited

We own a 39 percent interest in Phoenix Park Gas Processors Limited, which processes natural gas in Trinidad and markets natural gas liquids in the Caribbean, Central America and the U.S. Gulf Coast. Facilities include a 2-billion-cubic-feet-per-day gas processing plant and a 70,000 barrel-per-day natural gas liquids fractionator.

Other

- San Juan Gas Plant We operate and own a 50 percent interest in the San Juan Gas Plant, a 550 million cubic-feet-per-day capacity natural gas processing plant in Bloomfield, New Mexico.
- Lost Cabin Gas Plant We operate and own a 46 percent interest in the Lost Cabin Gas Plant, a 313 million cubic-feet-per-day capacity natural gas processing facility in Lysite, Wyoming.
- Wingate Fractionator We operate and own the Wingate Fractionator, a 25,000 barrel-per-day capacity natural gas liquids fractionation plant located in Gallup, New Mexico.

Venezuela

In 2007, we announced we had been unable to reach agreement with respect to our migration to an *empresa mixta* structure mandated by the Venezuelan government s Nationalization Decree. As a result, Venezuela s national oil company, Petróleos de Venezuela S.A. (PDVSA), or its affiliates, directly assumed control over ConocoPhillips interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project. In response to this expropriation, we filed a request for international arbitration on November 2, 2007, with the World Bank s International Centre for Settlement of Investment Disputes (ICSID). An arbitration hearing was held before an ICSID tribunal during the summer of 2010, and we anticipate an interim decision on key legal and factual issues in 2013. In a separate commercial arbitration from the Company s ICSID claim discussed above, an International Chamber of Commerce (ICC) tribunal issued a decision in favor of the Company in September 2012, finding PDVSA owed $67 million for pre-expropriation breaches of the Petrozuata project agreements. In November 2012, based on the ICC tribunal ruling, PDVSA paid ConocoPhillips $68 million, including post-judgment interest, which resulted in a $61 million after-tax earnings increase. The Company also recognized additional income of $173 million after-tax associated with the reversal of a related contingent liability accrual.

Ecuador

In 2008, Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, initiated arbitration before ICSID against The Republic of Ecuador, as a result of the newly enacted Windfall Profits Tax Law and government-mandated renegotiation of our production sharing contracts. Despite a restraining order issued by ICSID, Ecuador confiscated the crude oil production of Burlington and its co-venturer and sold the illegally seized crude oil. In 2009, Ecuador took over operations in Blocks 7 and 21, fully expropriating our assets. In June 2010, the ICSID tribunal concluded it has jurisdiction to hear the expropriation claim. On April 24, 2012, Ecuador filed a supplemental counterclaim asserting environmental damages, which we believe are not material. The ICSID tribunal issued a decision on liability on December 14, 2012, in favor of Burlington,

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finding that Ecuador s seizure of Blocks 7 and 21 was an unlawful expropriation in violation of the Ecuador-U.S. Bilateral Investment Treaty. An additional arbitration phase will take place to determine the damages owed to ConocoPhillips for Ecuador s actions.

Peru

Exploration

We own a 45 percent operating interest in Blocks 123 and 129, covering nearly 1.6 million net acres. In October 2012, we announced our decision not to pursue further exploration activities in Blocks 123 and 129. This decision to withdraw is part of our strategic plan to optimize our portfolio of assets.

CANADA

Our Canadian operations mainly consist of natural gas fields in western Canada and oil sands developments in the Athabasca Region of northeastern Alberta. In 2012, Canada operations contributed 15 percent of our worldwide liquids production and 21 percent of our natural gas production.

			2012			
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Bitumen MBD	Total MBOED
Average Daily Net Production						
Western Canada	Various %	Various	37	857	-	180
Surmont	50.0	ConocoPhillips	-	-	12	12
Foster Creek	50.0	Cenovus	-	-	51	51
Christina Lake	50.0	Cenovus	-	-	30	30
Total Canada			37	857	93	273

Western Canada

Our operations in western Canada are primarily comprised of three core development areas: Deep Basin, Kaybob and O Chiese, which extend from central Alberta to northeastern British Columbia. We operate or have ownership interests in approximately 80 natural gas processing plants in the region, and, as of December 31, 2012, held leasehold rights in 5.9 million net acres in western Canada.

Oil Sands

We hold approximately 1.1 million net acres of land in the Athabasca Region of northeastern Alberta. Our bitumen resources in Canada are produced via an enhanced thermal oil recovery method called steam-assisted gravity drainage (SAGD), whereby steam is injected into the reservoir, effectively liquefying the heavy bitumen, which is recovered and pumped to the surface for further processing.

Surmont

The Surmont oil sands leases are located approximately 35 miles south of Fort McMurray, Alberta. Surmont is a 50/50 joint venture with Total S.A. Surmont Phase 2 construction began in 2010, with production startup targeted for 2015. Following startup, Surmont s gross production capacity is estimated to be 150 MBOED, with net peak production of 65 MBOED anticipated by 2018.

FCCL

We have a 50/50 heavy oil business venture with Cenovus Energy Inc., FCCL Partnership, a Canadian upstream general partnership. FCCL s assets, operated by Cenovus, include the Foster Creek, Christina Lake and Narrows Lake SAGD bitumen developments.

Construction continued in 2012 on both the Foster Creek and Christina Lake properties. At Christina Lake, Phase D was completed and production came on stream in the third quarter of 2012. Phase D

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added 40 MBOED of gross production capacity, bringing total gross production capacity to 98 MBOED. Phase E is expected to be completed in 2013, with first production targeted for the second half of 2013, which will add another 40 MBOED of gross production capacity. Phase F was sanctioned in the fourth quarter of 2012, with production startup anticipated in 2016, which will add an additional 50 MBOED of gross production capacity.

At Foster Creek, construction progressed on Phases F, G and H, which are estimated to be completed in 2014, 2015 and 2016, respectively. These phases will add approximately 125 MBOED of gross production capacity. FCCL anticipates submitting an application for regulatory approval for an additional expansion, Phase J, in 2013.

Narrows Lake is a new oil sands development within the FCCL Partnership. In May 2012, FCCL received approval from the Alberta government to proceed with Narrows Lake. Narrows Lake Phase A was sanctioned in the fourth quarter of 2012, and initial production is anticipated in 2017.

Parsons Lake/Mackenzie Gas Project

We were involved with three other energy companies, as members of the Mackenzie Gas Project, on the development of the Mackenzie Valley Pipeline and gathering system, which was 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 natural gas field, one of the primary fields in the Mackenzie Delta, which would anchor the pipeline development. Due to a continued decline in market conditions and lack of acceptable commercial terms, the project was suspended indefinitely in the first quarter of 2012. As a result, we recorded a $520 million after-tax impairment in 2012 for the carrying value of capitalized development costs and associated undeveloped leasehold costs.

Amauligak

We have a 53.8 percent operating interest in Amauligak, which lies approximately 31 miles offshore in shallow water in the Beaufort Sea. A range of development options are being evaluated.

Exploration

We hold exploration acreage in four areas of Canada: offshore eastern Canada, onshore western Canada, the Mackenzie Delta/Beaufort Sea Region and the Arctic Islands.

Unconventional Exploration

During 2012, we drilled unconventional test wells in the Duvernay and Montney plays. In 2013, exploration activities will continue in Duvernay, the Canol Shale in the Northwest Territories, Muskwa in the Horn River Basin and the Montney play. We also plan to continue delineating potential development opportunities in the oil sands.

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EUROPE

The Europe segment consists of operations principally located in the Norwegian and U.K. sectors of the North Sea, as well as exploration activities in Poland and Greenland. In 2012, operations in Europe contributed 17 percent of our worldwide liquids production and 13 percent of natural gas production.

Norway

			2012		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Greater Ekofisk Area	35.1 %	ConocoPhillips	66	52	75
Alvheim	20	Marathon	14	14	16
Heidrun	24	Statoil	11	10	13
Other	Various	Various	17	84	31
Total Norway			108	160	135

The Greater Ekofisk Area, located approximately 200 miles offshore Stavanger, Norway in the North Sea, is comprised of four producing fields: Ekofisk, Eldfisk, Embla and Tor. Crude oil is exported to Teesside, England, and the natural gas is exported to Emden, Germany. The Ekofisk South and Eldfisk II developments continue, with production expected in the fourth quarters of 2013 and 2014, respectively.

The Alvheim development consists of a floating production, storage and offloading (FPSO) vessel and subsea installations. Produced crude oil is exported via shuttle tankers, and natural gas is transported to the United Kingdom via a pipeline to the Beryl-Sage system.

The Heidrun Field is located in the Norwegian Sea. Produced crude oil is transported to Mongstad in Norway and Tetney in the United Kingdom by double-hulled shuttle tankers. Part of the natural gas is transported and sold to buyers in Europe, while the remainder is used as feedstock in a methanol plant in Norway, in which we own an 18.3 percent interest.

We also have varying ownership interests in five other producing fields in the Norway sector of the North Sea and in the Norwegian Sea.

In the second quarter of 2012, we sold our Norway and U.K. interests in the Statfjord Field and associated satellites.

Exploration

During 2012, we completed the evaluation of available acreage for the 22nd Licensing Round and submitted an application in December.

Transportation

We own a 35.1 percent interest in the Norpipe Oil Pipeline System, a 220-mile pipeline which carries crude oil from Ekofisk to a crude oil stabilization and natural gas liquids processing facility in Teesside, England. In addition, we own a 1.9 percent interest in Norwegian Continental Shelf Gas Transportation (Gassled), which owns most of the Norwegian gas transportation infrastructure.

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United Kingdom

			2012		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Britannia	58.7 %	Britannia Operator Ltd.	4	117	24
Britannia Satellites	75.0-83.5	ConocoPhillips	13	23	17
J-Area	32.5-36.5	ConocoPhillips	8	59	18
Southern North Sea	Various	Various	-	98	16
East Irish Sea	100	HRL	-	56	9
Other	Various	Various	9	3	9
Total United Kingdom			34	356	93

In addition to our interest in the Britannia natural gas and condensate field, we own 50 percent of Britannia Operator Limited, the operator of the field. Condensate is delivered through the Forties Pipeline to an oil stabilization and processing plant near the Grangemouth Refinery in Scotland, while natural gas is transported through Britannia s line to St. Fergus, Scotland. The Britannia satellite fields, Callanish and Brodgar, produce via subsea manifolds and pipelines linked to the Britannia platform.

J-Area is comprised of the Judy/Joanne, Jade and Jasmine fields, located in the U.K. Central North Sea. Development of the Jasmine Field continued during 2012, and we anticipate first production in the fourth quarter of 2013. Jasmine is estimated to achieve average net peak production of 37 MBOED in 2014.

We have various ownership interests in 18 producing gas fields in the Rotliegendes and Carboniferous areas of the Southern North Sea. Our interests in the East Irish Sea include the Millom, Dalton and Calder fields, which are operated on our behalf by a third party.

We own a 24 percent interest in the Clair Field, located in the Atlantic Margin. The development of Clair Ridge received government approval in October 2011, and initial production is estimated to occur in 2016.

We sold our interest in the Alba Field in the second quarter of 2012.

Exploration

We were awarded three licenses during 2012, one in the East Irish Sea and two in the Central Graben, North Sea. We approved the Greater Clair exploration and appraisal program in 2012 and plan to commence drilling in 2013.

Transportation

We have a 10 percent interest in the Interconnector Pipeline, which links the United Kingdom and Belgium and facilitates the marketing throughout Europe of natural gas produced in the United Kingdom. In January 2013, we entered into an agreement to sell our equity interest. The sale is expected to close in the first quarter of 2013.

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

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Poland

Exploration

We are participating in a shale gas venture in Poland. In the third quarter of 2012, we exercised our option to acquire a 70 percent interest in Lane Energy Poland and assumed operatorship for three western Baltic Basin concessions. Four wells have been drilled on these concessions, with further well tests and drilling planned for 2013. A 3-D seismic survey is also planned for the first quarter of 2013.

Greenland

Exploration

During 2012, we successfully completed a 2-D seismic survey in Block 7011/11 of the Qamut license in West Greenland and recovered stratigraphic cores which will guide the interpretation of this new data. In addition, we have completed the evaluation of available acreage in East Greenland.

ASIA PACIFIC AND MIDDLE EAST

The Asia Pacific and Middle East segment has exploration and production operations in China, Indonesia, Malaysia, Australia and the Timor Sea; producing operations in Qatar; and exploration activities in Bangladesh and Brunei. In 2012, operations in the Asia Pacific and Middle East segment contributed 13 percent of our worldwide liquids production and 28 percent of natural gas production.

Australia and Timor Sea

			2012		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Australia Pacific LNG	37.5 %	Origin Energy	-	118	20
Bayu-Undan	56.9	ConocoPhillips	27	195	59
Athena/Perseus	50	ExxonMobil	-	35	6
Total Australia and Timor Sea			27	348	85

Australia Pacific LNG

Australia Pacific LNG Pty Ltd (APLNG), our joint venture with Origin Energy and China Petrochemical Corporation (Sinopec), is focused on producing CBM from the Bowen and Surat basins in Queensland, Australia. Origin operates APLNG s production and pipeline system, and we will operate the LNG facility. Natural gas is currently sold to domestic customers, while progress continues on the development of an LNG processing and export sales business. Once established, this will enhance our LNG position and serve as an additional LNG hub supplying Asia Pacific markets. Two initial 4.5-million-tonnes-per-year LNG trains have been sanctioned, with approximately 9,000 net wells ultimately envisioned to supply both the domestic gas market and the LNG development. The additional wells will be supported by expanded gas gathering systems, centralized gas processing and compression stations, and water treatment facilities, in addition to a new export pipeline from the gas fields to the LNG facilities.

During 2011, three significant milestones were achieved. First, the development received environmental approval from the Australian federal government. Second, definitive agreements were signed with Sinopec for the supply of up to 4.3 million tonnes of LNG per year for 20 years. The agreements also specified terms under which Sinopec subscribed for a 15 percent equity interest in APLNG, with both our ownership interest and Origin Energy s ownership interest diluting from 50 percent to 42.5 percent. The Subscription Agreement was completed in August 2011. Third, a binding Heads of Agreement was signed with Japan-based Kansai Electric Power Co. Inc., for the sale of approximately 1 million tonnes of LNG per year for 20 years.

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In January 2012, APLNG and Sinopec signed an amendment to their existing LNG sales agreement for the sale and purchase of an additional 3.3 million tonnes of LNG per year through 2035. This agreement, in combination with the Kansai Electric agreement, finalized the marketing of the second train. In July 2012, we sanctioned the development of the second 4.5-million-tonnes-per-year LNG production train. Start-up of the second train is expected to occur in the fourth quarter of 2015, with resulting LNG exports commencing shortly thereafter sold under the binding sales agreements to Sinopec and Kansai Electric. Upon sanctioning of the second train in July and in conjunction with the LNG sales agreement, Sinopec subscribed to additional shares in APLNG, which increased its equity interest from 15 percent to 25 percent. As a result, on July 12, 2012, both our ownership interest and Origin Energy s ownership interest diluted from 42.5 percent to 37.5 percent.

APLNG executed project financing agreements for an $8.5 billion project finance facility during the third quarter of 2012 and began drawing on the financing in October 2012. Our reduced ownership interest, coupled with Sinopec s $2.1 billion injection into APLNG associated with the dilution and APLNG s successful placement of the $8.5 billion of project financing, will lower our future capital requirements to fund the project. We are evaluating opportunities to further reduce our ownership interest in APLNG. In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility, which will be released upon meeting certain completion milestones.

For additional information, see Note 3 Variable Interest Entities (VIEs), Note 6 Investments, Loans and Long-Term Receivables, and Note 13 Guarantees, in the Notes to Consolidated Financial Statements.

Bayu-Undan

The Bayu-Undan gas condensate field is located in the Timor Sea Joint Petroleum Development Area between Timor-Leste and Australia. We also operate and own a 56.9 percent interest in the associated Darwin LNG Facility, located at Wickham Point, Darwin. Produced natural gas is used to supply the Darwin LNG Plant. In 2012, we sold 148 billion gross cubic feet of LNG to utility customers in Japan.

During the first half of 2013, the Bayu-Undan Phase 3 Development will focus on procuring long-lead items and securing contracts for a semi-submersible drilling rig. Final Investment Decision is expected in mid-2013 and will be followed by further detailed engineering and procurement activities. Drilling is anticipated to commence in the second quarter of 2014.

ConocoPhillips served a Notice of Arbitration on the Timor-Leste Minister of Finance in October 2012 for outstanding disputes related to a series of tax assessments. Between 2010 and 2012, ConocoPhillips has paid, under protest, tax assessments totaling approximately $227 million, which are primarily recorded in the Investments and long-term receivables line on our December 31, 2012, consolidated balance sheet. The arbitration will be conducted in Singapore under the United Nations Commission on International Trade Laws (UNCITRAL) arbitration rules, pursuant to the terms of the Tax Stability Agreement with the Timor-Leste Government. The arbitration process is currently underway. Future impacts on our business are not known at this time.

Athena/Perseus

The Athena production license (WA-17-L) is located offshore Western Australia and contains part of the Perseus Field which straddles the boundary with WA-1-L, an adjoining license area. Natural gas is produced from these licenses.

Greater Sunrise

We have a 30 percent interest in the Greater Sunrise gas and condensate field located in the Timor Sea. Although the Sunrise Joint Venture and the governments of Australia and Timor-Leste are aligned with the objective to develop the Greater Sunrise Field, key challenges must be resolved before significant funding commitments can be made. These include gaining agreement between both governments and the joint venture on a development concept.

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Exploration

Conventional Exploration

We operate three permits located in the Browse Basin, offshore northwest Australia. We own a 60 percent interest in two of the permits, WA-315-P and WA-398-P, and a 10 percent interest in WA-314-P. Phase I of the 2009/2010 drilling campaign resulted in discoveries in WA-315-P and WA-398-P. Phase II of the drilling campaign, expected to consist of a five-to-eight well program, commenced in 2012. The first well, Boreas-1, discovered hydrocarbons and was completed, plugged and abandoned in 2012. The second well, Zephyros-1, is currently being drilled and is expected to reach targeted depth in the first quarter of 2013.

In the Bonaparte Basin, offshore northern Australia, we operate and own interests in three permits, NT/RL5, NT/P69 and NT/P61. In 2012, we farmed-down our interest from 60 percent to 37.5 percent. A three-well appraisal program is expected to commence in 2014.

Unconventional Exploration

In September 2011, we executed a farm-in agreement to acquire a 75 percent working interest in four exploration permits: EP-443, EP-450, EP-451 and EP-456, which cover approximately 11 million gross acres in the Canning Basin of Western Australia. In 2012, our 75 percent interest in the permits was approved, and Phase I of a three-well drilling program commenced in the third quarter of 2012 with the drilling of the first well, Nicolay-1. The second well, Gibb-Maitland-1, was spud in December 2012. Upon completion of the Phase I drilling program, we will have the right to assume operatorship of the exploration permits.

Indonesia

				2012	
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
South Natuna Sea Block B	40.0 %	ConocoPhillips	12	115	31
South Sumatra	45.0-54.0	ConocoPhillips	2	322	56
Total Indonesia			14	437	87

We operate four production sharing contracts (PSCs) in Indonesia: the offshore South Natuna Sea Block B and three onshore PSCs, the Corridor Block and South Jambi B , both located in South Sumatra, and Warim in Papua. Our producing assets are primarily concentrated in two core areas: South Natuna Sea and onshore South Sumatra.

South Natuna Sea Block B

The offshore South Natuna Sea Block B PSC has 2 producing oil fields and 16 natural gas fields in various stages of development. Natural gas production is sold under international sales agreements to Malaysia and Singapore.

South Sumatra

The Corridor PSC consists of six oil fields and six natural gas fields in various stages of development. Natural gas is supplied from the Grissik and Suban gas processing plants to the Duri steamflood in central Sumatra and to markets in Singapore, Batam and West Java. The South Jambi B PSC includes three gas fields in various stages of development.

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Exploration

We own and operate an 80 percent interest in the Warim onshore exploration PSC in Papua. During 2012, we relinquished the Kuma and Arafura Sea offshore exploration PSCs.

Transportation

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

China

			2012		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Peng Lai	49.0 %	ConocoPhillips	30	3	31
Panyu	24.5	CNOOC	9	-	9
Total China			39	3	40

The Peng Lai 19-3, 19-9 and 25-6 fields are located in Bohai Bay Block 11/05. Production from the Phase I development of the PL 19-3 Field began in 2002. The Phase II development includes six drilling and production platforms and an FPSO vessel used to accommodate production from all the fields.

In January 2012, we and the China National Offshore Oil Corp. (CNOOC) announced an agreement with China s Ministry of Agriculture to resolve fishery-related issues in connection with two separate seepage incidents which occurred near the Peng Lai 19-3 Platforms B and C in 2011. Under this agreement, approximately $160 million was paid as compensation to settle private claims of potentially affected fishermen in relevant Bohai Bay communities, and public claims for alleged fishery damage. The agreement fulfills the objectives of the compensation fund we announced in September 2011. As part of this agreement, we have also designated approximately $16 million of our previously announced environmental fund to be used to improve fishery resources and for related projects.

In April 2012, we and CNOOC announced an agreement with China s State Oceanic Administration (SOA) related to claims for possible impacts of the Peng Lai 19-3 seepage incidents on the Bohai Bay marine environment. Under this agreement, approximately $173 million will be paid to resolve claims, and approximately $18 million will be paid to support environmental initiatives focused on improving marine environment protection in Bohai Bay. Of the total $191 million, $86 million was paid in 2012.

We hold a 49 percent ownership interest in the Peng Lai fields.

The SOA required implementation of preventative measures to avoid recurrence of the incidents, in addition to the filing of an updated environmental impact assessment (EIA) and overall development plan (ODP) for approval. A revised ODP was submitted to China s National Development and Reform Commission in November 2011, and a revised EIA was submitted to the SOA in February 2012. The EIA was approved in October 2012, and the ODP was approved in December 2012. In February 2013, we received notification from the SOA, which granted approval for a step-by-step resumption of normal production operations at the Peng Lai 19-3 Field in Bohai Bay.

The Panyu development, located in the South China Sea, is comprised of three oil fields: Panyu 4-2, Panyu 5-1 and Panyu 11-6. During 2012, a production platform was added to each of the Panyu 4-2 and Panyu 5-1 fields. Production from the new platforms began in September 2012.

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Exploration

Unconventional Exploration

In 2012, we entered into an agreement with Sinopec Southern Exploration Company to execute a joint study over the Qijiang Shale Gas Block, located in the Sichuan Basin. The Qijiang Shale Gas Block covers an area of 3,917 square kilometers. The study, which will be carried out over two years and includes seismic and drilling obligations, will be an important step in evaluating the potential for shale gas exploration in the area.

Malaysia

				2012	
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Gumusut	33.0 %	Shell	1	-	1
Total Malaysia			1	-	1

We own interests in four deepwater PSCs located off the eastern Malaysian state of Sabah: Block G, Block J, the Kebabangan (KBB) Cluster and SB-311. We have a 35 percent interest in Block G; 40 percent in Block J; 30 percent in KBB; and 40 percent in SB-311. First production from Gumusut, located in Block J, occurred in the fourth quarter of 2012. Production from a permanent, semi-submersible floating production and storage vessel is expected in late 2013, with estimated net annual peak production of 32 MBOED anticipated in 2014. The development of the KBB gas field commenced in 2011, with first production anticipated in late 2014. Estimated net annual peak production from KBB of 29 MBOED is expected in 2015. Development of the Siakap North-Petai oil field began in 2012, and first production is expected in late 2013. The Malikai oil field, sanctioned in the fourth quarter of 2012, is the fourth field under development. First production is anticipated in early 2017.

Exploration

In December 2012, we were formally awarded operatorship of exploration block SB-311, offshore Sabah. A two-well drilling program is planned for this block, and we expect to complete seismic reprocessing and acquisition in 2013.

Vietnam

We sold our Vietnam business in the first quarter of 2012. Net production averaged 3 MBOED in 2012.

Bangladesh

Exploration

In 2009, we were formally awarded two deepwater blocks in the Bay of Bengal, offshore Bangladesh. We received government approval of the PSC terms in June 2011 and hold 100 percent interests in Blocks 10 and 11. In 2012, we performed 2-D seismic activities and are currently evaluating the results.

Brunei

Exploration

We have a 6.25 percent working interest in Block CA-2. Two exploration wells were expensed as dry holes in 2011. Exploration activities continued during 2012, and we plan to drill a third well in 2013.

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Qatar

	Interest	Operator	Liquids MBD	2012 Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Qatargas 3	30.0 %	Qatargas Operating Co.	23	367	84
Total Qatar			23	367	84

Qatargas 3 (QG3) is an integrated development jointly owned by Qatar Petroleum (68.5 percent), ConocoPhillips (30 percent) and Mitsui & Co., Ltd. (1.5 percent). QG3 is comprised of upstream natural gas production facilities to produce approximately 1.4 billion gross cubic feet per day of natural gas from Qatar s North Field over a 25 year life. It also includes a 7.8-million-gross-tonnes-per-year LNG facility, from which LNG is shipped in leased LNG carriers destined for sale globally. First gas production was achieved in October 2010, and we achieved peak production during 2011.

QG3 executed the development of the onshore and offshore assets as a single integrated development with Qatargas 4 (QG4), a joint venture between Qatar Petroleum and Royal Dutch Shell plc. This included 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 QG3 and QG4 joint ventures. Production from the LNG trains and associated facilities are combined and shared.

OTHER INTERNATIONAL

The Other International segment includes exploration and producing operations in Libya and Russia, as well as exploration activities in Angola and the Caspian Sea. In 2012, we agreed to sell our Nigerian and Algerian businesses and our interest in the Republic of Kazakhstan s North Caspian Sea Production Sharing Agreement (Kashagan). As such, results of these operations have been reclassified to discontinued operations for all periods presented. During 2012, operations in Other International contributed 6 percent of our worldwide liquids production.

Libya

	Interest	Operator	Liquids MBD	2012 Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Waha Concession	16.3 %	Waha Oil Co.	40	18	43
Total Libya			40	18	43

The Waha Concession consists of multiple concessions and encompasses nearly 13 million gross acres in the Sirte Basin. Our production operations in Libya and related oil exports were temporarily suspended in 2011 during Libya s period of civil unrest. Production restarted in late 2011 and reached 49 MBOED in November 2012.

Exploration

We participated in an exploration appraisal program within the Waha Concession in 2012 and are currently evaluating results. We drilled three appraisal wells during 2012 and completed one exploration well in early 2013.

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Russia

	Interest	Operator	Liquids MBD	2012 Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Naryanmarneftegaz (NMNG)	30.0 %	OOO NMNG	8	-	8
Polar Lights	50.0	Polar Lights Co.	5	-	5
Total Russia			13	-	13

NMNG

We sold our interest in NMNG in the third quarter of 2012.

Polar Lights

Polar Lights Company is an entity which has developed several fields in the Timan-Pechora Basin in northern Russia.

Angola

Exploration

Effective January 1, 2012, we entered into two PSCs with Angola s national oil company. We have a 30 percent operating interest in Blocks 36 and 37, both of which are located in Angola s subsalt play trend. In 2012, we acquired 3-D seismic data for both ultra-deepwater blocks and are currently evaluating the data. The first wildcat well is expected to be spud in 2014.

Kazakhstan

Transportation

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

Exploration

We disposed of our interest in the N Block, located offshore Kazakhstan, in January 2013.

Discontinued Operations

Nigeria

	Interest	Operator	Liquids MBD	2012 Natural Gas MMCFD	Total MBOED

Average Daily Net Production*					
OMLs 60, 61, 62, 63	20.0 %	Eni	16	149	40
Total Nigeria			16	149	40

**Reclassified to discontinued operations.*

We have an interest in four onshore Oil Mining Leases (OMLs). Natural gas is sourced from our proved reserves in the OMLs and provides fuel for a 480-megawatt gas-fired power plant in Kwale, Nigeria. We have a 20 percent interest in this power plant, which supplies electricity to Nigeria s national electricity supplier. In 2012, the plant consumed 12 million net cubic feet per day of natural gas.

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

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In December 2012, we entered into an agreement to sell our entire Nigerian business. The transaction is expected to close by mid-2013.

Algeria

	Interest	Operator	Liquids MBD	2012 Natural Gas MMCFD	Total MBOED
Average Daily Net Production*					
Menzel Lejmat North	65.0 %	ConocoPhillips	8	-	8
		L Organization			
Ourhoud	3.7	Ourhoud	3	-	3
Total Algeria			11	-	11

**Reclassified to discontinued operations.*

Our activities in Algeria are centered around the following fields in Block 405a: the Menzel Lejmat North Fields (MLN), the Ourhoud Field and the EMK Field. Crude oil production from MLN and Ourhoud is transported to northern Algerian ports where it is sold. The development of the EMK Field, in which we own a 16.9 percent interest, was sanctioned in 2009. Startup is anticipated in mid-2013.

In December 2012, we entered into an agreement to sell our entire Algerian business. The transaction is expected to close by mid-2013.

Kazakhstan

In the Caspian Sea, we have an 8.4 percent interest in Kashagan. In November 2012, we announced our intention to sell our entire interest in Kashagan. The transaction is expected to close by mid-2013, subject to customary governmental approvals.

LUKOIL INVESTMENT

This segment represents our former investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. We sold our remaining interest in LUKOIL in the first quarter of 2011.

OTHER

Marketing Activities

Our Commercial organization manages our worldwide commodity portfolio, which mainly includes natural gas, crude oil, bitumen, natural gas liquids and LNG. Marketing activities are performed through offices in the United States, Canada, Europe and Asia. In marketing our production, we attempt to minimize flow disruptions, maximize realized prices and manage credit-risk exposure. Commodity sales are generally made at prevailing market prices at the time of sale. We also purchase third-party volumes to better position the Company to fully utilize transportation and storage capacity and satisfy customer demand.

Natural Gas

Our natural gas production, along with third-party purchased gas, is marketed in the United States, Canada, Europe and Asia. Our natural gas is sold to a diverse client portfolio which includes local distribution companies; gas and power utilities; large industrials; independent, integrated or state-owned oil and gas companies; as well as marketing companies. To reduce our market exposure and credit risk, we also transport natural gas via firm and interruptible transportation agreements to major market hubs.

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Crude Oil, Bitumen and Natural Gas Liquids

Our crude oil, bitumen and natural gas liquids revenues are derived from production in the United States, Canada, Australia, Asia, Africa, China and Europe. These commodities are primarily sold under contracts with prices based on market indices, adjusted for location, quality and transportation.

Spill Containment

Marine Well Containment Company

We are a founding member of the Marine Well Containment Company (MWCC), a non-profit organization formed in 2010 which provides well containment equipment and technology in the deepwater U.S. Gulf of Mexico. In 2011, MWCC launched an interim containment system designed to improve containment response capabilities in the event of an underwater well control incident. In 2012, MWCC and the U.S. Bureau of Safety and Environmental Enforcement announced the successful demonstration of the industry s ability to respond to a deepwater well control incident in the U.S. Gulf of Mexico. MWCC is advancing this capability and is currently developing an expanded containment system with significantly increased capacity. The expanded containment system is expected to be available in 2013.

Subsea Well Response Project

In 2011, we, along with eight leading oil and gas companies, launched the Subsea Well Response Project (SWRP), an initiative designed to enhance the industry s capability to respond to international subsea well control incidents. In 2012, SWRP, a non-profit organization based in Stavanger, Norway, partnered with Oil Spill Response Limited, a non-profit organization in the United Kingdom, in order to develop integrated intervention systems which are more widely available to the industry. This complements the work being undertaken in the United States by MWCC and also in the United Kingdom by the Oil Spill Prevention and Response Advisory Group (OSPRAG), enhancing our global well response capabilities. We are also a participant in OSPRAG.

LNG Technology

Our Optimized Cascade® LNG liquefaction technology business continues to grow with the demand for new LNG plants. The technology has been applied in 10 LNG trains around the world, with 10 more under construction.

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, 2012. No difference exists between our estimated total proved reserves for year-end 2011 and year-end 2010, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2012.

DELIVERY COMMITMENTS

We sell crude oil and natural gas from our 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 4 trillion cubic feet of natural gas, including approximately 600 billion cubic feet related to the noncontrolling interests of consolidated subsidiaries, and 80 million barrels of crude oil in the future. These contracts have various expiration dates through the year 2028. We expect to fulfill the majority of these delivery commitments with proved developed reserves. In addition, we anticipate using proved undeveloped reserves and spot market purchases to fulfill these remaining commitments. See the disclosure on Proved Undeveloped Reserves in the Oil and Gas Operations section following the Notes to Consolidated Financial Statements, for information on the development of proved undeveloped reserves.

COMPETITION

We compete with private, public and state-owned companies in all facets of the E&P business. Some of our competitors are larger and have greater resources. Each of our segments is highly competitive, with no single competitor, or small group of competitors, dominating.

We compete with numerous other companies in the industry, including state-owned companies, to locate and obtain new sources of supply and to produce oil, bitumen, natural gas liquids and natural gas in an efficient, cost-effective manner. Based on publicly available year-end 2011 reserves statistics, we had the seventh-largest total of worldwide proved reserves of nongovernment-controlled companies. We deliver our production into the worldwide commodity markets. Principal methods of competing include geological, geophysical and engineering research and technology; experience and expertise; economic analysis in connection with portfolio management; and efficiently operating oil and gas producing properties.

GENERAL

At the end of 2012, we held a total of 784 active patents in 54 countries worldwide, including 319 active U.S. patents. During 2012, we received 15 patents in the United States and 47 foreign patents. Our products and processes generated licensing revenues of $124 million in 2012. 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 $221 million, $193 million and $172 million in 2012, 2011 and 2010, respectively.

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

The environmental information contained in Management s Discussion and Analysis of Financial Condition and Results of Operations on pages 58 through 62 under the captions Environmental and Climate Change is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2012 and those expected for 2013 and 2014.

Website Access to SEC Reports

Our Internet website address is *www.conocophillips.com*. Information contained on our Internet website 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 website, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the U.S. Securities and Exchange Commission (SEC). Alternatively, you may access these reports at the SEC s website at *www.sec.gov*.

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Item 1A. RISK FACTORS

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

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

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

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

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

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

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

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

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

- The discharge of pollutants into the environment.
- Emissions into the atmosphere (such as nitrogen oxides, sulfur dioxide and mercury emissions, and greenhouse gas emissions as they are, or may become, regulated).
- The handling, use, storage, transportation, disposal and cleanup of hazardous materials and hazardous and nonhazardous wastes.

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- The dismantlement, abandonment and restoration of our properties and facilities at the end of their useful lives.
- Exploration and production activities in certain areas, such as offshore environments, arctic fields, oil sands reservoirs and shale gas plays.

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

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

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

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

Actions of the U.S., state, local and foreign governments, through tax and other legislation, executive order and commercial restrictions, could reduce our operating profitability both in the United States and abroad. In certain locations, governments have imposed or proposed restrictions on our operations; special taxes or tax assessments; and payment transparency regulations that could require us to disclose competitively sensitive information or might cause us to violate non-disclosure laws of other countries. The U.S. government can also 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 host governments have affected operations significantly in the past, such as the expropriation of our oil assets by the Venezuelan government, and may continue to do so in the future.

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 56 percent of our hydrocarbon production from continuing operations was derived from production outside the United States in 2012, and 57 percent of our proved reserves, as of December 31, 2012, was located outside the United States. We are subject to risks associated with operations in international markets, including changes in foreign governmental policies relating to crude oil, natural gas liquids, bitumen, natural gas or LNG pricing and taxation, other political, economic or diplomatic developments, changing political conditions and international monetary fluctuations.

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

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, natural gas, bitumen and natural gas liquids wells below actual production capacity. Because legal requirements are frequently changed and subject to interpretation, we cannot predict the effect of these requirements.

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

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

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

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

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

The scope and nature of our operations present a variety of significant hazards and risks, including operational hazards and risks such as explosions, fires, pipeline interruptions, pipeline ruptures, crude oil spills, severe weather, geological events, labor disputes, or cyber attacks. Our operations are also subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks. All such hazards could result in loss of human life, significant property and equipment damage, environmental pollution, impairment of operations, substantial losses to us and damage to our reputation.

Our technologies, systems and networks may be subject to cybersecurity breaches. Although we have experienced occasional, actual or attempted breaches of our cybersecurity, none of these breaches has had a material effect on our business, operations or reputation. If our systems for protecting against cybersecurity risks prove to be insufficient, we could be adversely affected by having our business systems compromised, our proprietary information altered, lost or stolen, or our business operations disrupted.

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Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 3. LEGAL PROCEEDINGS

The following is a description of reportable legal proceedings, including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment for this reporting period. The following proceedings include those matters that arose during the fourth quarter of 2012, as well as matters previously reported in our 2011 Form 10-K and our first-, second- and third-quarter 2012 Form 10-Qs that were not resolved prior to the fourth quarter of 2012. Material developments to the previously reported matters have been included in the descriptions below. While it is not possible to accurately predict the final outcome of these pending proceedings, if any one or more of such proceedings was decided adversely to ConocoPhillips, we expect there would be no material effect on our consolidated financial position. Nevertheless, such proceedings are reported pursuant to SEC regulations.

New Matters

The New Mexico Environment Department has issued four Notices of Violation (NOVs) to ConocoPhillips alleging a total of twenty individual violations for failure to comply with air emission recordkeeping, reporting and testing requirements at various natural gas compression operations in northwestern New Mexico. These violations are alleged to have occurred between 2006 and 2012. The agency is seeking a penalty of over $100,000. We have submitted responses to all four of the NOVs and will work with the agency to resolve these matters.

Matters Previously Reported ConocoPhillips

The North Dakota Department of Health has requested all the operators in the Bakken Pool area, including ConocoPhillips, enter into an Administrative Consent Agreement to resolve alleged historic violations of the state s air emission regulations. The state is proposing a penalty of $2,000 per well drilled in the Bakken Pool which would result in total penalty to the company of over $100,000. ConocoPhillips is working with the state to resolve this matter.

Matters Previously Reported Phillips 66

On April 30, 2012, the separation of our Downstream business was completed, creating two independent energy companies: ConocoPhillips and Phillips 66. In connection with the separation, we entered into an Indemnification and Release Agreement, which provides for cross-indemnities between Phillips 66 and us and established procedures for handling claims subject to indemnification and related matters, such as legal proceedings. We have included matters where we remain a party to a proceeding relating to Phillips 66, in accordance with SEC regulations. We do not expect any of those matters to result in a net claim against us.

On September 19, 2012, the Bay Area Air Quality Management District (District) issued a $213,500 demand to settle fourteen NOVs issued in 2009 and 2010 with respect to alleged violations of regulatory and/or permit requirements at the Phillips 66 Rodeo Refinery. Phillips 66 is working with the District to resolve this matter.

On October 15, 2012, the District issued a $313,000 demand to settle thirteen NOVs issued in 2010 and 2011 with respect to alleged violations of regulatory and/or permit requirements at the Phillips 66 Rodeo Refinery. Phillips 66 is working with the District to resolve this matter.

On March 7, 2012, the District issued a $302,500 demand to settle five NOVs issued between 2008 and 2010 to the Phillips 66 Rodeo Refinery. The NOVs allege non-compliance with the District rules and/or facility permit conditions. Phillips 66 is working with the District to resolve this matter.

In May 2012, the Illinois Attorney General s office filed and served a Complaint against ConocoPhillips with respect to operations at the Phillips 66 Wood River Refinery alleging violations of the Illinois groundwater standards and a third-party s hazardous waste permit. The Complaint seeks as relief remediation of area groundwater, compliance with the hazardous waste permit, enhanced pipeline and tank integrity measures, additional spill reporting, and yet-to-be specified amounts for fines and penalties. Phillips 66 is working with the Illinois Environmental Protection Agency and Attorney General s office to resolve these allegations.

In December 2011, ConocoPhillips was notified by the U.S. Environmental Protection Agency (EPA) of alleged violations related to the use of Renewable Identification Numbers (RINs). Phillips 66 was one of several companies who entered Administrative Settlement Agreements (ASAs) with the EPA to settle allegations it had used invalid RINs for its 2010 and 2011 fuel program compliance. Under this Agreement, Phillips 66 will pay a maximum of $350,000 in penalties for the use of invalid RINs. Payments are made upon demand from the EPA. To date, $250,000 has been paid and it is anticipated the EPA will demand the final $100,000 in 2013.

On November 28, 2011, the Phillips 66 Borger Refinery received a Notice of Enforcement from the Texas Commission on Environmental Quality (TCEQ) for alleged emissions events that occurred during inclement weather in January and February 2011. The TCEQ is seeking a penalty of $120,000. Phillips 66 is working with TCEQ to resolve this matter.

In October 2011, ConocoPhillips was notified by the Attorney General of the State of California it was conducting an investigation into possible violations of the regulations relating to the operation of underground storage tanks at gas stations in California. On January 3, 2013, we were served with a lawsuit filed by the California Attorney General that alleges such violations. Philips 66 is contesting these allegations.

In October 2007, we received a Complaint from the EPA alleging violations of the Clean Water Act related to a 2006 oil spill at the Phillips 66 Bayway Refinery and proposing a penalty of $156,000. Phillips 66 is working with the EPA and the U.S. Coast Guard to resolve this matter.

On May 19, 2010, the Phillips 66 Lake Charles Louisiana Refinery received a Consolidated Compliance Order and Notice of Potential Penalty from the Louisiana Department of Environmental Quality (LDEQ) alleging various violations of applicable air emission regulations, as well as certain provisions of the consent decree in Civil Action No. H-01-4430. Phillips 66 is working with the LDEQ to resolve this matter.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

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EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Position Held	Age*
Ellen R. DeSanctis	Vice President, Investor Relations and Communications	56
Sheila Feldman	Vice President, Human Resources	58
Matt J. Fox	Executive Vice President, Exploration and Production	52
Alan J. Hirshberg	Executive Vice President, Technology and Projects	51
Janet L. Kelly	Senior Vice President, Legal, General Counsel and Corporate Secretary	55
Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer	50
Glenda M. Schwarz	Vice President and Controller	47
Jeff W. Sheets	Executive Vice President, Finance and Chief Financial Officer	55
Don E. Wallette, Jr.	Executive Vice President, Commercial, Business Development and Corporate Planning	54

**On February 15, 2013.*

There are no family relationships among any of the officers named above. Each officer of the Company is elected by the Board of Directors at its first meeting after the Annual Meeting of Stockholders and thereafter as appropriate. Each officer of the Company holds office from the date of election until the first meeting of the directors held after the next Annual Meeting of Stockholders or until a successor is elected. The date of the next annual meeting is May 14, 2013. Set forth below is information about the executive officers.

Ellen R. DeSanctis was appointed Vice President, Investor Relations and Communications in May 2012. She was previously employed by Petrohawk Energy Corp. and served as Senior Vice President, Corporate Communications since 2010. Prior to that she was employed by Rosetta Resources Inc. and served as Executive Vice President of Strategy and Development from 2008 to 2010.

Sheila Feldman was appointed Vice President, Human Resources in May 2012. She was previously employed by Arch Coal, Inc. and served as Vice President, Human Resources since 2003.

Matt J. Fox was appointed Executive Vice President, Exploration and Production in May 2012. Prior to that, he was employed by Nexen, Inc. and served as Executive Vice President, International since 2010. He was previously employed by ConocoPhillips and served as President, ConocoPhillips Canada from 2009 to 2010 and Senior Vice President, Oil Sands and Canadian Arctic from 2007 to 2009.

Alan J. Hirshberg was appointed Executive Vice President, Technology and Projects in May 2012. Prior to that, he served as Senior Vice President, Planning and Strategy since 2010. He was previously employed by Exxon Mobil Corporation and served as Vice President, Worldwide Deepwater and Africa Projects since 2009; Vice President, Worldwide Deepwater Projects from 2008 to 2009; and Vice President, Established Areas Projects from 2006 to 2008.

Janet L. Kelly was appointed Senior Vice President, Legal, General Counsel and Corporate Secretary in 2007.

Ryan M. Lance was appointed Chairman of the Board of Directors and Chief Executive Officer in May 2012, having previously served as Senior Vice President, Exploration and Production International since May 2009. Prior to that, he served as President, Exploration and Production Asia, Africa, Middle East and Russia/Caspian since April 2009; and President, Exploration and Production Europe, Asia, Africa and the Middle East from 2007 to 2009.

Glenda M. Schwarz was appointed Vice President and Controller in 2009. She previously served as General Auditor and Chief Ethics Officer from 2008 to 2009.

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Jeff W. Sheets was appointed Executive Vice President, Finance and Chief Financial Officer in May 2012. Prior to that, he served as Senior Vice President, Finance and Chief Financial Officer since 2010 and Senior Vice President, Planning and Strategy since 2008.

Don E. Wallette, Jr. was appointed Executive Vice President, Commercial, Business Development and Corporate Planning in May 2012. Prior to that, he served as President, Asia Pacific since 2010 and President, Russia/Caspian from 2006 to 2010.

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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
2012				
First	**$**	**78.29**	**68.00**	**0.66**
Second		**77.31**	**50.62**	**0.66**
Third		**58.90**	**52.84**	**0.66**
Fourth		**59.65**	**53.95**	**0.66**
2011				
First	$	81.80	66.50	0.66
Second		81.75	70.08	0.66
Third		80.13	60.40	0.66
Fourth		73.90	58.65	0.66

Closing Stock Price at December 31, 2012	$	57.99
Closing Stock Price at January 31, 2013	$	58.00
Number of Stockholders of Record at January 31, 2013*		56,511

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

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased*		Average Price Paid Per Share	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, 2012	5,165	$	57.39	-	$	4,901
November 1-30, 2012	-		-	-		4,901
December 1-31, 2012	7,359		57.67	-		4,901

Total	12,524	$	57.56	-

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

***On December 2, 2011, we announced a share repurchase program to repurchase up to $10 billion of common stock over the next two years. Acquisitions for the share repurchase program are made at management s discretion, at prevailing prices, subject to market conditions and other factors. Repurchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock repurchased under the plan are held as treasury shares.*

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Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2012	2011	2010	2009	2008
Sales and other operating revenues	$ **57,967**	64,196	56,215	47,879	87,468
Income (loss) from continuing operations	**7,481**	7,188	10,305	3,737	(19,483)
Per common share					
Basic	**5.95**	5.18	6.93	2.46	(12.83)
Diluted	**5.91**	5.14	6.88	2.44	(12.83)
Net income (loss)	**8,498**	12,502	11,417	4,492	(16,279)
Net income (loss) attributable to ConocoPhillips	**8,428**	12,436	11,358	4,414	(16,349)
Per common share					
Basic	**6.77**	9.04	7.68	2.96	(10.73)
Diluted	**6.72**	8.97	7.62	2.94	(10.73)
Total assets	**117,144**	153,230	156,314	152,138	142,865
Long-term debt	**20,770**	21,610	22,656	26,925	27,085
Joint venture acquisition obligation long-term	**2,810**	3,582	4,314	5,009	5,669
Cash dividends declared per common share	**2.64**	2.64	2.15	1.91	1.88

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

Net income (loss) and Net income (loss) attributable to ConocoPhillips for all periods presented includes income from discontinued operations as a result of the separation of the Downstream business and our intention to sell our interest in Kashagan and our Nigerian and Algerian businesses. Income from discontinued operations for these operations was $1,017 million in 2012, $5,314 million in 2011, $1,112 million in 2010, $755 million in 2009 and $3,204 million in 2008. For additional information, see Note 2 Discontinued Operations, in the Notes to Consolidated Financial Statements.

The financial data for 2010 includes the impact of $5,563 million before-tax ($4,463 million after-tax) related to gains from asset dispositions and LUKOIL share sales.

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

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

Item 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
February 19, 2013

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 included elsewhere in this report. It contains forward-looking statements including, without limitation, statements relating to the Company s plans, strategies, objectives, expectations and intentions that are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The words anticipate, estimate, believe, budget, continue, could, intend, may, plan, potential, predict, would, expect, objective, projection, forecast, goal, guidance, outlook, effort, target and similar expressions identify forward- The Company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the Company s disclosures under the heading: CAUTIONARY STATEMENT FOR THE PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995, beginning on page 67.

Due to the separation of the downstream businesses and our intention to sell our interest in the North Caspian Sea Production Sharing Agreement (Kashagan) and our Nigerian and Algerian businesses in 2012, which are reported as discontinued operations, income (loss) from continuing operations is more representative of ConocoPhillips as an independent exploration and production company. The terms earnings and loss as used in Management s Discussion and Analysis refer to income (loss) from continuing operations.

BUSINESS ENVIRONMENT AND EXECUTIVE OVERVIEW

ConocoPhillips is the world s largest independent exploration and production (E&P) company, based on proved reserves and production of liquids and natural gas. Headquartered in Houston, Texas, we have operations and activities in 30 countries. At December 31, 2012, we had approximately 16,900 employees worldwide and total assets of $117 billion. Our stock is listed on the New York Stock Exchange under the symbol COP.

Discontinued Operations

On April 30, 2012, we completed the separation of our downstream businesses into an independent, publicly traded company, Phillips 66. Our refining, marketing and transportation businesses, most of our Midstream segment, our Chemicals segment, as well as our power generation and certain technology operations included in our Emerging Businesses segment (collectively, our Downstream business), were transferred to Phillips 66. As a part of our strategic asset disposition program, in the fourth quarter of 2012, we agreed to sell our interest in Kashagan and our Nigerian and Algerian businesses. Results of operations related to Phillips 66, Kashagan, Nigeria and Algeria have been classified as discontinued operations in all periods presented in this Annual Report on Form 10-K. For additional information, see Note 2 Discontinued Operations, in the Notes to Consolidated Financial Statements.

Overview

As an independent E&P company, we are solely focused on our core business of exploring for, developing and producing crude oil and natural gas globally. Our portfolio primarily includes legacy assets in North America, Europe, Asia and Australia; growing North American shale and oil sands businesses; several major international developments; and a global exploration program. Our value proposition to our shareholders is to deliver

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production and cash margin growth, competitive returns on capital, and a compelling dividend, while keeping our fundamental commitment to safety, operating excellence and environmental stewardship. We expect to achieve our value proposition through portfolio optimization, investments in high-margin developments, applying technical capability and maintaining financial flexibility.

In our first year as an independent E&P company, we achieved production of 1.58 million barrels of oil equivalent per day (BOED), including production from discontinued operations of .05 million BOED; advanced our growth and drilling programs; paid dividends on our common stock of $3.3 billion for the full year; and repurchased 80 million shares of our common stock at a total cost of $5.1 billion. In 2012, we also announced plans to raise $8 $10 billion of proceeds from asset dispositions by the end of 2013. As part of this program, we have generated $2.1 billion in proceeds from asset dispositions through December 31, 2012. We have also announced asset sales, expected to close by mid-2013, which will generate approximately $9.6 billion in additional proceeds. In the near-term, we will fund a portion of our capital program with these proceeds. Over the next five years, our investment in high-margin developments should position us to deliver 3 5 percent annual production volume and margin growth, enabling us to fund our capital program organically.

Our total capital program is expected to be $15.8 billion in 2013, compared to $15.7 billion in 2012. Excluding Kashagan, Nigeria and Algeria, which are reported as discontinued operations, our 2013 capital program is expected to be $15.5 billion, compared to $14.9 billion in 2012. Our investments will be directed predominantly toward high-quality developments already underway in the United States, Canada, the United Kingdom and Norwegian North Sea, Malaysia and Australia, as well as exploration opportunities which will build our inventory for the future.

Key Operating and Financial Highlights

Significant highlights during 2012 included the following:

- Completed the separation of our Downstream business on April 30, 2012, creating two independent energy companies, ConocoPhillips and Phillips 66.
- Achieved annual production of 1.58 million BOED, including production from discontinued operations of .05 million BOED, and generated earnings of $7.5 billion.
- Achieved annual organic reserve replacement of 156 percent and year-end proved reserves of 8.6 billion barrels of oil equivalent.
- Repurchased 80 million ConocoPhillips shares, representing 6 percent of our outstanding shares.
- Paid quarterly dividends of 66 cents per share, consistent with pre-separation dividends.
- Exceeded 100,000 BOED production milestone in the Eagle Ford; continued Bakken activity ramp up.
- Exceeded 100,000 BOED average production in the Canadian Oil sands in the fourth quarter of 2012.
- Progressed FCCL expansion with sanction of Christina Lake Phase F and Narrows Lake Phase A.
- Achieved first oil from the Gumusut Field in Malaysia.
- Increased deepwater Gulf of Mexico position to 1.7 million acres; continued appraisal drilling. Expect to increase acreage position to 2.0 million acres in the first quarter of 2013.
- Increased Niobrara acreage position to approximately 130,000 acres; continued drilling and testing of unconventional shale plays.
- Progressed the Australia Pacific LNG Project with sanction of the second train in early July 2012; secured $8.5 billion project finance facility.
- Advanced the disposition program with the announcement of agreements to sell Kashagan, Algeria and Nigeria, generating approximately $8.5 billion in expected proceeds.

Business Environment

In recent years, the business environment for the energy industry has experienced many challenges which have influenced our operations and profitability, largely due to factors beyond our control, such as the recent financial crisis, geopolitical events or fears thereof, environmental laws, tax regulations, governmental policies, and weather-related disruptions. These factors generally influence the supply and demand of crude oil and natural gas. The most significant factor impacting our profitability and related reinvestment of our

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operating cash flows into our business is commodity prices. The prices for commodity products are supply- and demand-based and can be very volatile; therefore, to navigate through the volatility, our strategy is to maintain a core portfolio of low-risk, high-return development programs associated with legacy assets, coupled with a portfolio of development opportunities which offer high-margin growth, such as unconventional plays, deepwater and arctic drilling, and liquefied natural gas (LNG).

Operating and Financial Priorities

Important factors we must continue to manage well in order to be successful include:

- Operating 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. We strive to conduct our business with respect and care for both the local and global environment and systematically manage risk to drive sustainable business growth.

There has been heightened public focus on the safety of the oil and gas industry as a result of the 2010 Deepwater Horizon incident in the Gulf of Mexico. Safety and environmental stewardship, including the operating integrity of our assets, remain our highest priorities. In 2010, we formed a non-profit organization, the Marine Well Containment Company LLC (MWCC), with Exxon Mobil Corporation, Chevron Corporation and Royal Dutch Shell plc, to develop a new oil spill containment system and improve industry spill response in the U.S. Gulf of Mexico. To complement this work internationally, in 2011, we and several leading oil and gas companies established the Subsea Well Response Project in Norway, and we participated in the Oil Spill Prevention and Response Advisory Group in the United Kingdom.

- Adding to our proved reserve base. We primarily add to our proved reserve base in three ways:
  - Successful exploration, exploitation and development of new and existing fields.
  - Application of new technologies and processes to improve recovery from existing fields.
  - Acquisition of existing fields.

Through a combination of the methods listed above, we have been successful in the past in maintaining or adding to our production and proved reserve base, and we anticipate being able to do so in the future. In the five years ended December 31, 2012, our organic reserve replacement was 108 percent, excluding LUKOIL and the impact of sales and purchases.

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.

- Disciplined investment approach. We participate in a capital-intensive industry. 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 construct pipelines and LNG facilities. We use a disciplined approach to select the appropriate projects which will provide the most attractive investment opportunities, with a continued focus on higher-margin liquids plays and limited investment in North American conventional natural gas. As investments bring more liquids production online, we expect a corresponding shift in our production mix. However, there are often long lead times from the time we make an investment to the time the investment is operational and begins generating financial returns.

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Our $15.8 billion capital program includes contributions to FCCL of $0.8 billion. Our capital expenditures and investment budget for 2013, excluding FCCL, is $15.0 billion, compared to actual capital expenditures and investments in 2012 of $15.0 billion. Excluding discontinued operations for Kashagan, Nigeria and Algeria, we estimate 2013 capital expenditures and investments will be $14.7 billion, compared to $14.2 billion in 2012. Approximately 10 percent of the 2013 capital budget is expected to be directed toward maintenance of our legacy base portfolio; 40 percent is expected to be allocated to exploitation programs in our legacy asset base, which is intended to offset natural decline from these assets; 35 percent is expected to be spent on sanctioned major developments, such as Eldfisk II, Jasmine and APLNG; and 15 percent is planned for our worldwide exploration and appraisal program, which will target both conventional and unconventional plays.

Portfolio optimization. We continue to optimize our asset portfolio by focusing on assets which offer the highest returns and growth potential, while selling nonstrategic holdings. In 2012, we announced plans to sell an additional $8 $10 billion of noncore assets through the end of 2013. During 2012, we sold our Vietnam business, the Statfjord and Alba fields in the North Sea, our investment in Naryanmarneftegaz (NMNG) in Russia, and we further diluted our interest in APLNG from 42.5 percent to 37.5 percent. We recently announced our intention to sell our 8.4 percent interest in Kashagan, our Algerian and Nigerian businesses, and certain properties in the Cedar Creek Anticline, located in North Dakota and Montana. Cedar Creek Anticline is expected to close in the first quarter of 2013, and the remaining transactions are expected to close by mid-2013, subject to customary governmental approvals. Additionally, in January 2013, we sold our 24.5 percent interest in the N Block, located offshore Kazakhstan.

In 2011, we sold certain noncore assets in the Lower 48 and western Canada, and we completed the divestiture of our entire interest in LUKOIL.

Controlling costs and expenses. Since we cannot control the prices of the commodity products we sell, controlling operating and overhead costs, within the context of our commitment to safety and environmental stewardship, is a high priority. We monitor these costs using various methodologies that are reported to senior management monthly, on both an absolute-dollar basis and a per-unit basis. Because managing operating and overhead costs is critical to maintaining competitive positions in our industry, cost control is a component of our variable compensation programs. Operating and overhead costs increased 8 percent in 2012 compared with 2011, primarily as a result of major turnaround expenses in Australia, higher operating expenses in the Lower 48 associated with improved production as a result of increased drilling programs, the settlement of environmental claims and other costs related to Bohai Bay, China, and costs associated with the separation of Phillips 66.

Developing and retaining a talented work force. We strive to attract, train, develop and retain individuals with the knowledge and skills to implement our business strategy and who support our values and ethics. Throughout the company, we focus on the continued learning, development and technical training of our employees. Professional new hires participate in structured development programs designed to accelerate their technical and functional skills.

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Other significant factors that can affect our profitability include:

Commodity prices. Our earnings generally correlate with industry price levels for crude oil and natural gas. These are commodity products, the prices of which are subject to factors external to our company and over which we have no control. The following table depicts the average benchmark prices for West Texas Intermediate (WTI) crude oil, Dated Brent crude oil and U.S. Henry Hub natural gas:

		Dollars Per Unit		
		2012	2011	2010
Market Indicators				
WTI (per barrel)	$	**94.16**	95.05	79.39
Dated Brent (per barrel)		**111.58**	111.27	79.47
U.S. Henry Hub first of month (per million British thermal units)		**2.79**	4.04	4.39

Global oil prices remained relatively flat in 2012, compared to 2011. In 2012, global oil demand grew at approximately the same pace as in 2011, at about 0.9 percent or 800 thousand barrels per day, as the pace of economic expansion moderated due to intentional slowing in China, coupled with fiscal uncertainties in the European Union and the United States. Global oil production rose due to an increase in the Organization of Petroleum Exporting Countries (OPEC) and North American production. WTI continued to trade at a discount to Brent throughout 2011 and 2012, mainly due to high inventory levels and excess crude supply in the U.S. Midcontinent market, largely as a result of limited pipeline capacity.

Henry Hub natural gas prices decreased 31 percent in 2012, compared with 2011. U.S. natural gas prices were depressed in 2012, mainly due to high inventory levels, a warmer-than-normal winter and sustained production from shale plays. We expect these factors will continue to moderate natural gas prices in the near- to mid-term. The expansion in shale production has also helped boost supplies of natural gas liquids, resulting in downward pressure on natural gas liquids prices in the United States. As a result, our domestic realized natural gas liquids price declined 30 percent in 2012 compared with 2011. Our realized bitumen price declined 14 percent in 2012. We expect bitumen prices to remain weak in the near-term, until additional heavy refining capacity comes on-line.

In recent years, the use of hydraulic fracturing in shale natural gas formations has led to increased industry actual and forecasted natural gas production in the United States. Although providing short- and long-term significant growth opportunities for our company, the increased abundance of natural gas due to development of shale plays could also have adverse financial implications to us, including: an extended period of low natural gas and natural gas liquids prices; production curtailments on properties that produce primarily natural gas; continued delay of plans to develop Alaska North Slope natural gas fields; and underutilization of LNG regasification facilities. Should one or more of these events occur, our revenues would be reduced and additional impairments might be possible.

Impairments. As mentioned above, we participate in capital-intensive industries. At times, our properties, plants and equipment and investments become impaired when, for example, our reserve estimates are revised downward, commodity prices decline significantly for long periods of time, or a decision to dispose of an asset leads to a write-down to its fair value. We may also invest large amounts of money in exploration which, if exploratory drilling proves unsuccessful, could lead to a material impairment of leasehold values. Before-tax impairments in 2012 totaled $1.2 billion and primarily resulted from the impairments of the Mackenzie Gas Project and associated leaseholds in Canada; Cedar Creek Anticline in the Lower 48; various properties in Europe, which have ceased production or are nearing the end of their useful lives; and the N Block in the Caspian Sea. Before-tax impairments in 2011 totaled $0.8 billion and primarily resulted from the impairments of our equity

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investment in NMNG and certain Canadian natural gas properties. For additional information, see Note 9 Impairments, in the Notes to Consolidated Financial Statements.

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

Fiscal and regulatory environment. Our operations can be affected by changing economic, regulatory and political environments in the various countries in which we operate, including the United States. Civil unrest or strained relationships with governments may impact our operations or investments. These changing environments have generally negatively impacted our results of operations, and further changes to government fiscal take could have a negative impact on future operations. Our production operations in Libya and related oil exports were temporarily suspended in 2011 during Libya s period of civil unrest. Our assets in Venezuela and Ecuador were expropriated in 2007 and 2009, respectively. In Canada, the Alberta provincial government changed the royalty structure in 2009 to tie a component of the new rate to prevailing prices. Our management carefully considers these events when evaluating projects or determining the level of activity in such countries.

Outlook

Total production for the first quarter of 2013 is expected to be 1.58 million to 1.6 million BOED, including production from discontinued operations of approximately 40,000 BOED. Full-year 2013 production from continuing operations is expected to be 1.475 million to 1.525 million BOED,which is consistent with 2012 production from continuing operations adjusted for dispositions.

Segment Analysis

We manage our operations through six operating segments, which are defined by geographic region: Alaska, Lower 48 and Latin America, Canada, Europe, Asia Pacific and Middle East, and Other International.

The LUKOIL Investment segment represents our prior investment in the ordinary shares of OAO LUKOIL, which was sold in the first quarter of 2011.

Corporate and Other represents costs not directly associated with an operating segment, such as most interest expense, corporate overhead, costs related to the separation of Phillips 66 and certain technology activities, as well as licensing revenues received.

Our key performance indicators, shown in the statistical tables provided at the beginning of the operating segment sections that follow, reflect results from our continuing operations, including commodity prices and production.

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RESULTS OF OPERATIONS

Consolidated Results

A summary of the company s income (loss) from continuing operations by business segment follows:

		Millions of Dollars	
Years Ended December 31	**2012**	2011	2010
Alaska	$ **2,276**	1,984	1,727
Lower 48 and Latin America	**1,029**	1,288	1,029
Canada	**(684)**	91	2,902
Europe	**1,498**	1,830	1,703
Asia Pacific and Middle East	**3,996**	3,093	2,153
Other International	**359**	(377)	(417)
LUKOIL Investment	**-**	239	2,513
Corporate and Other	**(993)**	(960)	(1,305)
Income from continuing operations	$ **7,481**	7,188	10,305

2012 vs. 2011

Earnings for ConocoPhillips increased 4 percent in 2012. The increase was mainly due to:

- Higher gains from asset sales. In 2012, gains from asset dispositions were $1,567 million after-tax, compared with gains in 2011 from asset dispositions and LUKOIL share sales of $141 million after-tax.
- Higher LNG and crude oil prices.
- Lower production taxes, mainly as a result of lower volumes.
- The benefit from the realization of a tax loss carryforward of $236 million.
- The favorable resolution of pending claims and settlements of $235 million after-tax.

These items were partially offset by:

- Lower volumes, largely due to dispositions and reduced production in China.
- Lower natural gas, natural gas liquids and bitumen prices.
- Higher operating and selling, general and administrative (SG&A) expenses, which included pension settlement expenses of $87 million after-tax and separation costs of $84 million after-tax.
- Higher impairments. Non-cash impairments in 2012 totaled $900 million after-tax, compared with impairments in 2011 of $698 million after-tax.

2011 vs. 2010

Earnings for ConocoPhillips decreased 30 percent in 2011. The decrease was mainly due to:

- Lower gains from asset sales. In 2011, gains from asset dispositions and LUKOIL share sales were $141 million after-tax, compared with gains in 2010 of $4,463 million after-tax.
- The absence of equity earnings from LUKOIL due to the divestiture of our interest.

Lower production volumes.

These items were partially offset by:

- Higher commodity prices. Commodity price benefits were partly offset by increased production taxes.
- Lower depreciation, depletion and amortization (DD&A) expenses, mainly as a result of lower volumes.

Income Statement Analysis

2012 vs. 2011

Sales and other operating revenues decreased 10 percent in 2012, mainly due to lower natural gas and natural gas liquids prices, partly offset by higher LNG prices.

Equity in earnings of affiliates increased 54 percent in 2012. The increase primarily resulted from:

- Improved earnings from Qatar Liquefied Gas Company Limited (3) (QG3), mainly due to higher LNG prices, partly offset by lower volumes.
- Lower impairments from NMNG. In 2011, equity earnings included a $395 million impairment of our equity investment.

Gain on dispositions increased $1,287 million in 2012. Gains in 2012 primarily resulted from the disposition of our Vietnam business, our equity investment in NMNG, the Statfjord and Alba fields in the North Sea and our interest in Block 39 in Peru, partly offset by the loss on further dilution of our equity interest in APLNG from 42.5 percent to 37.5 percent. Gains in 2011 mainly consisted of the divestiture of our remaining LUKOIL shares and the disposition of certain properties located in the Lower 48 and Canada, partially offset by the loss on the initial dilution of our equity interest in APLNG from 50 percent to 42.5 percent. For additional information, see Note 5 Assets Held for Sale or Sold and Note 6 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.

Other income increased 78 percent in 2012, mostly as a result of the favorable resolution of the Petróleos de Venezuela S.A. (PDVSA) International Chamber of Commerce (ICC) arbitration. For additional information, see Note 14 Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Purchased commodities decreased 15 percent in 2012, largely as a result of lower U.S. natural gas prices, partly offset by higher purchased volumes.

Production and operating expenses increased 6 percent in 2012, mostly due to major turnaround expenses at our Bayu-Undan Field and Darwin LNG facility and higher operating expenses in the Lower 48.

SG&A expenses increased 28 percent in 2012, primarily due to pension settlement expense and costs associated with the separation of Phillips 66.

Exploration expenses increased 45 percent in 2012, mostly due to the impairment of undeveloped leasehold costs associated with the Mackenzie Gas Project as a result of its indefinite suspension in the first quarter of 2012.

Impairments increased 112 percent in 2012. Impairments in 2012 included the $213 million impairment of capitalized development costs associated with the Mackenzie Gas Project in the first quarter of 2012, the $192 million property impairment related to the disposition of Cedar Creek Anticline, as well as increases in the asset retirement obligation for various properties mostly located in the United Kingdom, which have ceased production or are nearing the end of their useful lives. Impairments in 2011 consisted of various North American natural gas properties. For additional information, see Note 9 Impairments, in the Notes to Consolidated Financial Statements.

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Taxes other than income taxes decreased 11 percent in 2012, mostly due to lower production taxes as a result of lower crude oil production volumes.

Interest and debt expense decreased 26 percent in 2012, primarily due to higher capitalized interest on projects and lower interest expense due to lower average debt levels.

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

2011 vs. 2010

Sales and other operating revenues increased 14 percent in 2011, mainly due to significantly higher prices for crude oil and higher LNG prices and volumes. Lower crude oil and natural gas volumes partly offset this increase.

Equity in earnings of affiliates decreased 10 percent in 2011. The decrease primarily resulted from the absence of equity earnings from LUKOIL due to the divestiture of our interest. This decrease was partially offset by:

- Earnings from QG3, primarily due to sales of LNG following production startup, which occurred in October 2010.
- Lower impairments from NMNG. In 2011, equity earnings included a $395 million impairment of our equity investment, and 2010 equity earnings included a $645 million impairment.
- Improved earnings from FCCL Partnership, mostly due to higher commodity prices and volumes.

Gain on dispositions decreased 93 percent in 2011. Gains in 2011 primarily resulted from the disposition of certain assets located in the Lower 48 and Canada, as well as the divestiture of our remaining LUKOIL shares. These gains were partially offset by the loss on dilution of our equity interest in APLNG from 50 percent to 42.5 percent. Gains in 2010 primarily reflected the $2,878 million gain realized from the sale of our interest in Syncrude, the $1,749 million gain on the divestiture of a portion of our LUKOIL shares, and gains on the disposition of certain assets located in the Lower 48 and Canada.

Purchased commodities increased 20 percent in 2011, mainly due to higher natural gas prices in Europe.

DD&A decreased 15 percent in 2011. The decrease was mostly associated with lower production volumes and lower unit-of-production rates related to reserve bookings in 2011.

Impairments increased $240 million in 2011, mostly due to the impairment of various North American natural gas properties in 2011.

Taxes other than income taxes increased 43 percent in 2011, mostly due to higher production taxes in Alaska as a result of higher crude oil prices.

Interest and debt expense decreased 18 percent in 2011, primarily due to lower average debt levels.

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

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Summary Operating Statistics

		2012	2011	2010
Average Net Production[1]				
Crude oil (MBD)[2]		**595**	622	733
Natural gas liquids (MBD)		**156**	145	147
Synthetic oil (MBD)		**-**	-	12
Bitumen (MBD)		**93**	67	59
Natural gas (MMCFD)[3]		**4,096**	4,359	4,465
Total Production (MBOED)[4]		**1,527**	1,561	1,695
		Dollars Per Unit		
Average Sales Prices				
Crude oil (per barrel)	**$**	**105.72**	105.52	77.74
Natural gas liquids (per barrel)		**46.36**	55.73	46.00
Synthetic oil (per barrel)		**-**	-	77.56
Bitumen (per barrel)		**53.91**	62.56	53.06
Natural gas (per thousand cubic feet)		**5.48**	5.80	5.05
		Millions of Dollars		
Worldwide Exploration Expenses				
General and administrative; geological and geophysical; and lease rentals	**$**	**626**	569	649
Leasehold impairment		**719**	159	241
Dry holes		**155**	310	235
	$	**1,500**	1,038	1,125

Excludes discontinued operations.

(1)Excludes amounts related to LUKOIL.

(2)Thousands of barrels per day.

(3)Millions of cubic feet per day. Represents quantities available for sale and excludes gas equivalent of natural gas liquids included above.

(4)Thousands of barrels of oil equivalent per day.

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2012, our continuing operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, offshore Timor-Leste in the Timor Sea, Indonesia, China, Malaysia, Qatar, Libya and Russia.

In 2012, average production from continuing operations decreased 2 percent compared with 2011, primarily as a result of normal field decline, the impact from asset dispositions and higher planned and unplanned downtime. These decreases were largely offset by additional production from major developments, mainly from shale plays in the Lower 48 and ramp-up of new phases at FCCL, the resumption of production in Libya following a period of civil unrest in 2011, and increased drilling programs in the Lower 48.

In 2011, average production decreased 8 percent compared with 2010, mostly as a result of suspended operations in Libya and Bohai Bay, China, asset dispositions and higher unplanned downtime. Normal field decline was largely offset by new production.

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Alaska

		2012	2011	2010
Income from Continuing Operations (millions of dollars)	$	**2,276**	1,984	1,727
Average Net Production				
Crude oil (MBD)		**188**	200	215
Natural gas liquids (MBD)		**16**	15	15
Natural gas (MMCFD)		**55**	61	82
Total Production (MBOED)		**213**	225	244
Average Sales Prices				
Crude oil (per barrel)	$	**109.62**	105.95	78.65
Natural gas (per thousand cubic feet)		**4.22**	4.56	4.62

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids, natural gas and LNG. In 2012, Alaska contributed 24 percent of our worldwide liquids production and 1 percent of our natural gas production.

2012 vs. 2011

Our Alaska operations reported earnings of $2,276 million in 2012, a 15 percent increase compared with earnings of $1,984 million in 2011. The increase in earnings was primarily due to higher crude oil prices, lower production taxes as a result of lower crude oil production volumes, the absence of the $54 million after-tax write-off of our investment associated with the cancellation of the Denali gas pipeline project in 2011, and lower DD&A. These increases were partly offset by lower crude oil sales volumes and higher operating expenses.

Production averaged 213 MBOED in 2012, a decrease of 5 percent compared with 2011. This decrease was mainly due to normal field decline, partially offset by lower unplanned downtime.

2011 vs. 2010

Alaska earnings were $1,984 million in 2011, a 15 percent increase compared with earnings of $1,727 million in 2010. Earnings in 2011 benefitted from significantly higher crude oil prices, partially offset by higher production taxes, lower volumes, higher operating expenses, and the $54 million after-tax write-off of the Denali gas pipeline project.

Production averaged 225 MBOED in 2011, a decrease of 8 percent compared with 2010. This decrease was mainly due to normal field decline, somewhat offset by increased drilling activity.

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Lower 48 and Latin America

		2012	2011	2010
Income from Continuing Operations (millions of dollars)	$	**1,029**	1,288	1,029
Average Net Production				
Crude oil (MBD)		**123**	94	85
Natural gas liquids (MBD)		**85**	74	75
Natural gas (MMCFD)		**1,493**	1,556	1,695
Total Production (MBOED)		**457**	428	442
Average Sales Prices				
Crude oil (per barrel)	$	**91.67**	92.79	73.52
Natural gas liquids (per barrel)		**35.45**	50.55	39.92
Natural gas (per thousand cubic feet)		**2.67**	3.99	4.25

During 2012, Lower 48 and Latin America contributed 25 percent of our worldwide liquids production and 37 percent of our natural gas production. The Lower 48 and Latin America segment primarily consists of operations located in the U.S. Lower 48 states.

2012 vs. 2011

Lower 48 and Latin America operations reported earnings of $1,029 million in 2012, a 20 percent decrease compared with 2011. The decrease in earnings was primarily the result of substantially lower natural gas and natural gas liquids prices; higher DD&A, mostly due to higher crude oil and natural gas liquids production; lower gains from asset dispositions; higher operating expenses and higher impairments. These decreases were partially offset by higher crude oil and natural gas liquids volumes. Earnings in 2012 also benefitted from the realization of a tax loss carryforward of $236 million, and the favorable resolution of the PDVSA ICC arbitration.

In November 2012, based on an ICC arbitration tribunal ruling, PDVSA paid ConocoPhillips $68 million for pre-expropriation breaches of the Petrozuata project agreements, which resulted in a $61 million after-tax earnings increase. The Company also recognized additional income of $173 million after-tax associated with the reversal of a related contingent liability accrual. These amounts included interest of $33 million after-tax, which has been reflected in the Corporate and Other segment. For additional information, see Note 14 Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Average production in the Lower 48 increased 7 percent in 2012, while average liquids production increased 24 percent over the same period. New production, primarily from the Eagle Ford, Bakken and Permian areas, and improved drilling and well performance more than offset normal field decline. In addition, higher unplanned downtime during 2012 partly offset the increase in production.

2011 vs. 2010

Lower 48 and Latin America earnings were $1,288 million in 2011, a 25 percent increase compared with 2010. The increase in 2011 earnings was mainly due to higher crude oil and natural gas liquids prices and lower DD&A. These increases were partly offset by lower gains from asset sales, lower natural gas prices, higher dry hole expenses and impairments.

Production averaged 428 MBOED in 2011, a 3 percent decrease compared with 2010. The decrease in 2011 was mainly due to asset dispositions. Normal field decline was offset by new production, mainly from the Eagle Ford, Bakken, Permian and Barnett areas, and improved drilling and well performance.

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Canada

	2012	2011	2010
Income (Loss) from Continuing Operations (millions of dollars)	$ **(684)**	91	2,902
Average Net Production			
Crude oil (MBD)	**13**	12	15
Natural gas liquids (MBD)	**24**	26	23
Synthetic oil (MBD)	**-**	-	12
Bitumen (MBD)			
Consolidated operations	**12**	10	10
Equity affiliates	**81**	57	49
Total bitumen	**93**	67	59
Natural gas (MMCFD)	**857**	928	984
Total Production (MBOED)	**273**	260	273
Average Sales Prices			
Crude oil (per barrel)	$ **78.26**	86.04	67.99
Natural gas liquids (per barrel)	**48.64**	56.84	47.68
Synthetic oil (per barrel)	**-**	-	77.56
Bitumen (dollars per barrel)			
Consolidated operations	**57.58**	55.16	51.10
Equity affiliates	**53.39**	63.93	53.43
Total bitumen	**53.91**	62.56	53.06
Natural gas (per thousand cubic feet)	**2.13**	3.46	3.74

Our Canadian operations are mainly comprised of natural gas fields in western Canada and oil sands developments in the Athabasca Region of northeastern Alberta. In 2012, Canada contributed 15 percent of our worldwide liquids production and 21 percent of our natural gas production.

2012 vs. 2011

Canada operations reported a loss of $684 million in 2012, a reduction of $775 million compared with earnings of $91 million in 2011. The decrease in earnings was largely due to significantly lower natural gas prices, lower bitumen prices and higher impairments, mainly as a result of the $520 million after-tax impairment of the Mackenzie Gas Project and associated leaseholds in 2012. These decreases were partially offset by significantly higher bitumen volumes from FCCL and lower DD&A from our western Canadian gas assets, primarily due to asset dispositions and curtailments. Equity earnings from FCCL were also impacted by higher operating and DD&A expenses, mostly as a result of higher production volumes.

Average production in Canada increased 5 percent in 2012, while average liquids production increased 24 percent over the same period. Normal field decline and the impact from asset dispositions were more than offset by new production from Christina Lake Phases C and D and improved well performance from Foster Creek, both in FCCL.

2011 vs. 2010

Canada earnings were $91 million in 2011, a reduction of $2,811 million compared with 2010. This decrease was primarily due to lower gains from asset dispositions. Earnings in 2010 included the $2,679 million after-tax gain realized from the sale of our 9.03 percent interest in the Syncrude oil sands mining operation. Lower volumes, mostly as a result of asset dispositions, impairments on various natural gas properties and lower

natural gas prices also contributed to the decrease in 2011 earnings. These decreases were somewhat offset by higher bitumen, natural gas liquids and crude oil prices, lower DD&A and lower dry hole expenses.

Production averaged 260 MBOED in 2011, a 5 percent decrease compared with 2010. The decrease was mainly due to asset dispositions and normal field decline, partly offset by new production from FCCL.

Europe

		2012	2011	2010
Income from Continuing Operations (millions of dollars)	$	**1,498**	1,830	1,703
Average Net Production				
Crude oil (MBD)		**135**	164	196
Natural gas liquids (MBD)		**7**	11	15
Natural gas (MMCFD)		**516**	626	815
Total Production (MBOED)		**228**	279	347
Average Sales Prices				
Crude oil (dollars per barrel)	$	**113.08**	111.82	79.74
Natural gas liquids (per barrel)		**61.53**	59.19	46.75
Natural gas (per thousand cubic feet)		**9.76**	9.26	6.94

The Europe segment consists of operations principally located in the Norwegian and U.K. sectors of the North Sea, as well as exploration activities in Poland and Greenland. In 2012, our Europe operations contributed 17 percent of our worldwide liquids production and 13 percent of our natural gas production.

2012 vs. 2011

Europe operations reported earnings of $1,498 million in 2012, an 18 percent decrease compared with 2011. The reduction in earnings was mainly due to lower volumes and higher impairments. Earnings for 2012 were also impacted by additional income tax expense due to legislation enacted in the United Kingdom in 2012, which restricted corporate tax relief on decommissioning costs. The additional tax expense resulted from the revaluation of deferred tax balances. These decreases to earnings were partly offset by a $287 million after-tax gain on sale of our interests in the Statfjord and Alba fields and lower DD&A. Additionally, earnings in 2011 included a $316 million increase in U.K. corporate income tax expense due to legislation enacted in 2011. This additional tax expense consisted of $106 million for the revaluation of deferred tax liabilities and $210 million to reflect the higher tax rates from the effective date of the legislation, March 24, 2011, through December 31, 2011.

Production averaged 228 MBOED in 2012, an 18 percent decrease compared with 2011. The decrease was mostly due to normal field decline, dispositions and higher unplanned downtime in the United Kingdom.

2011 vs. 2010

Earnings for our Europe operations were $1,830 million in 2011, a 7 percent increase compared with earnings of $1,703 million in 2010. Earnings benefitted from significantly higher prices and lower DD&A, partly offset by lower volumes and the $316 million increase in U.K. corporate income tax expense. Earnings in 2010 also benefitted from a $58 million insurance settlement.

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Production averaged 279 MBOED in 2011, a 20 percent decrease compared with 2010. The decrease mainly resulted from normal field decline, unplanned downtime and dispositions, somewhat offset by new production from Britannia and J-Block.

Asia Pacific and Middle East

	2012	2011	2010
Income from Continuing Operations (millions of dollars)	**$ 3,996**	3,093	2,153
Average Net Production			
Crude oil (MBD)			
Consolidated operations	**68**	99	122
Equity affiliates	**15**	16	2
Total crude oil	**83**	115	124
Natural gas liquids (MBD)			
Consolidated operations	**16**	12	18
Equity affiliates	**8**	7	1
Total natural gas liquids	**24**	19	19
Natural gas (MMCFD)			
Consolidated operations	**672**	695	712
Equity affiliates	**485**	492	169
Total natural gas	**1,157**	1,187	881
Total Production (MBOED)	**300**	332	290
Average Sales Prices			
Crude oil (dollars per barrel)			
Consolidated operations	**$ 108.20**	109.84	77.69
Equity affiliates	**108.07**	106.96	89.24
Total crude oil	**108.18**	109.46	77.89
Natural gas liquids (dollars per barrel)			
Consolidated operations	**79.26**	72.87	60.57
Equity affiliates	**77.30**	70.62	65.16
Total natural gas liquids	**78.64**	71.98	60.73
Natural gas (dollars per thousand cubic feet)			
Consolidated operations	**10.63**	9.82	7.39
Equity affiliates	**8.54**	5.93	1.91
Total natural gas	**9.75**	8.21	6.35

The Asia Pacific and Middle East segment has producing operations in China, Indonesia, Malaysia, Australia, the Timor Sea and Qatar, as well as exploration activities in Bangladesh and Brunei. During 2012, Asia Pacific and Middle East contributed 13 percent of our worldwide liquids production and 28 percent of our natural gas production.

2012 vs. 2011

Asia Pacific and Middle East operations reported earnings of $3,996 million in 2012, a 29 percent increase compared with 2011 earnings of $3,093 million. Earnings in 2012 primarily benefitted from higher gains from asset dispositions, significantly higher LNG prices, higher equity earnings due to lower DD&A and operating expenses from QG3, and lower Bohai Bay expenses incurred in 2012. Amounts realized from dispositions in

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2012 consisted of a $931 million after-tax gain on sale of our Vietnam business and a $133 million after-tax loss recognized on the further dilution of our equity interest in APLNG from 42.5 percent to 37.5 percent. In 2011, we recognized a $279 million after-tax loss on the initial dilution of our interest in APLNG from 50 percent to 42.5 percent. The increase in 2012 earnings was partly offset by lower crude oil volumes, mainly as a result of the Bohai Bay seepage incidents and the Vietnam disposition, lower LNG volumes and higher production taxes.

Average production decreased 10 percent in 2012. The decrease was largely due to the disposition of our Vietnam business, normal field decline, planned maintenance at our Bayu-Undan Field and Darwin LNG Facility in 2012, as well as lower production in China.

2011 vs. 2010

Asia Pacific and Middle East earnings increased 44 percent in 2011, compared with 2010 earnings. The increase was mainly due to higher prices, higher volumes, mostly as a result of a full year of LNG sales from QG3, and lower DD&A. These increases to earnings were partly offset by higher production taxes, higher operating expenses and the $279 million loss on dilution of our equity interest in APLNG from 50 percent to 42.5 percent.

Production averaged 332 MBOED in 2011, a 14 percent increase compared with 2010. The increase was largely due to the ramp-up of production from QG3, partly offset by higher unplanned downtime, mainly in China, and normal field decline.

Timor-Leste Arbitration

ConocoPhillips served a Notice of Arbitration on the Timor-Leste Minister of Finance in October 2012 for outstanding disputes related to a series of tax assessments. Between 2010 and 2012, ConocoPhillips has paid, under protest, tax assessments totaling approximately $227 million, which are primarily recorded in the Investments and long-term receivables line on our December 31, 2012, consolidated balance sheet. The arbitration will be conducted in Singapore under the United Nations Commission on International Trade Laws (UNCITRAL) arbitration rules, pursuant to the terms of the Tax Stability Agreement with the Timor-Leste Government. The arbitration process is currently underway. Future impacts on our business are not known at this time.

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Other International

	2012	2011	2010
Income (Loss) from Continuing Operations (millions of dollars)*	**$ 359**	(377)	(417)
Average Net Production*			
Crude oil (MBD)			
Consolidated operations	**40**	8	46
Equity affiliates	**13**	29	52
Total crude oil	**53**	37	98
Natural gas (MMCFD)	**18**	1	8
Total Production (MBOED)	**56**	37	99
Average Sales Prices*			
Crude oil (dollars per barrel)			
Consolidated operations	**$ 110.75**	98.30	79.22
Equity affiliates	**96.50**	101.62	74.33
Total crude oil	**107.56**	101.14	76.57
Natural gas (dollars per thousand cubic feet)	**5.55**	0.09	0.09

** Prior periods have been restated to exclude discontinued operations.*

The Other International segment includes producing operations in Libya and Russia, as well as exploration activities in Angola and the Caspian Sea. During 2012, Other International contributed 6 percent of our worldwide liquids production.

2012 vs. 2011

Other International operations reported earnings of $359 million in 2012, a $736 million increase compared with 2011. Earnings in 2012 primarily benefitted from the $443 million after-tax gain on disposition of our interest in NMNG, the absence of a $395 million after-tax impairment of our investment in NMNG in 2011, and higher earnings from Libya, as a result of the resumption of production following a period of civil unrest in 2011. These increases were partially offset by a $108 million after-tax impairment associated with the N Block in the Caspian Sea.

Production averaged 56 MBOED in 2012, a 51 percent increase compared with 2011 production. The increase was mainly due to the resumption of production in Libya, partly offset by field decline in Russia and the disposition of our interest in NMNG.

2011 vs. 2010

Other International reported a loss of $377 million in 2011, compared with a loss of $417 million in 2010. The improvement in 2011 was primarily the result of higher crude oil prices, higher equity earnings due to lower DD&A from NMNG and lower impairments. In 2011, we recorded a $395 million impairment of our equity investment in NMNG, compared with a $645 million impairment to NMNG recorded in 2010. These improvements in 2011 were partly offset by considerably lower volumes, mainly from Libya and Russia, as well as the absence of a deferred tax benefit recognized in 2010.

Production averaged 37 MBOED in 2011, a 63 percent decrease compared with 2010 production. The decrease was mostly due to suspended operations in Libya following a period of civil unrest in 2011, and field decline in Russia.

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Asset Dispositions

We recently announced our intention to sell our 8.4 percent interest in Kashagan and our Algerian and Nigerian businesses. The transactions are expected to close by mid-2013, subject to customary governmental approvals. In January 2013, we sold our 24.5 percent interest in the N Block, located offshore Kazakhstan.

LUKOIL Investment

		Millions of Dollars		
		2012	2011	2010
Income from Continuing Operations	**$**	**-**	239	2,513

This segment represents our former investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. We sold our remaining interest in LUKOIL in the first quarter of 2011.

2011 vs. 2010

Earnings in 2011 primarily represented the realized gain on remaining share sales. Earnings in 2010 primarily reflected earnings from the equity investment in LUKOIL we held at the time, in addition to gains on the partial sale of our LUKOIL investment.

Corporate and Other

		Millions of Dollars		
		2012	2011	2010
Income (Loss) from Continuing Operations				
Net interest	**$**	**(648)**	(710)	(995)
Corporate general and administrative expenses		**(313)**	(190)	(209)
Technology		**(4)**	15	(23)
Separation costs		**(84)**	(25)	-
Other		**56**	(50)	(78)
	$	**(993)**	(960)	(1,305)

2012 vs. 2011

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 9 percent in 2012, mostly due to higher capitalized interest, lower interest expense due to lower average debt levels, higher interest income and the $33 million after-tax interest benefit from the favorable resolution of the PDVSA arbitration. These improvements were partly offset by a $68 million after-tax premium on early debt retirement.

Corporate general and administrative expenses increased 65 percent in 2012, mainly due to $87 million of after-tax pension settlement expense and higher costs related to compensation and benefit plans.

Technology includes our investment in new technologies or businesses, as well as licensing revenues received. Activities are focused on heavy oil and oil sands; unconventional reservoirs; subsurface technology; liquefied natural gas; and arctic, deepwater and sustainability technology. Technology reported a loss of $4 million in 2012, compared to earnings of $15 million in 2011, primarily as a result of lower licensing revenues.

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Separation costs consist of expenses related to the separation of our Downstream business into a stand-alone, publicly traded company, Phillips 66. Separation costs increased $59 million in 2012 and mainly included costs related to compensation and benefit plans.

The category Other includes certain foreign currency transaction gains and losses, environmental costs associated with sites no longer in operation, and other costs not directly associated with an operating segment. The improvement in Other in 2012 was largely due to various tax-related adjustments, including a $39 million after-tax settlement. These improvements were partially offset by higher environmental expenses and foreign currency transaction losses.

2011 vs. 2010

Net interest decreased 29 percent in 2011, mostly due to lower interest expense, as a result of lower average debt levels. In addition, the absence of a $114 million after-tax premium on early debt retirement and the absence of $24 million of after-tax interest expense associated with a tax settlement, both of which occurred in 2010, contributed to the decrease.

Corporate general and administrative expenses decreased 9 percent in 2011, mainly due to lower costs related to compensation and benefit plans, partly offset by higher advertising expenses.

Technology had earnings of $15 million in 2011, as a result of higher licensing revenues, partially offset by higher project expenses.

Separation costs in 2011 primarily included legal, accounting and information systems costs.

Changes in the Other category primarily resulted from lower environmental costs and gains from foreign currency transactions, partially offset by a $20 million after-tax property impairment.

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CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars Except as Indicated		
	2012	2011	2010
Net cash provided by continuing operating activities	$ **13,458**	13,953	14,013
Net cash provided by discontinued operations	**464**	5,693	3,032
Short-term debt	**955**	1,013	936
Total debt	**21,725**	22,623	23,592
Total equity	**48,427**	65,749	69,124
Percent of total debt to capital*	**31 %**	26	25
Percent of floating-rate debt to total debt**	**9 %**	10	10

** Capital includes total debt and total equity.*

*** Includes effect of interest rate swaps.*

To meet our short- and long-term liquidity requirements, we look to a variety of funding sources. Cash generated from continuing operating activities is the primary source of funding. In addition, during 2012, we received $2,132 million in proceeds from asset sales and $1,996 million for the issuance of debt. During 2012, the primary uses of our available cash were $14,172 million to support our ongoing capital expenditures and investments; $5,098 million to repurchase common stock; $3,278 million to pay dividends on our common stock; and $2,565 million to repay debt. During 2012, cash and cash equivalents decreased by $2,162 million to $3,618 million.

In addition to cash flows from continuing operating activities and proceeds from asset sales, we rely on our commercial paper and credit facility programs and our shelf registration statement to support our short- and long-term liquidity requirements. We believe our current cash balance and cash generated by operations, together with access to external sources of funds as described below in the Significant Sources of Capital section, will be sufficient to meet our funding requirements in the near and long term, including our capital program, dividend payments, required debt payments and the funding requirements to FCCL.

Separation of Phillips 66

On April 30, 2012, the separation of our Downstream business was completed, creating two independent energy companies: ConocoPhillips and Phillips 66. Our refining, marketing and transportation businesses, most of our Midstream segment, our Chemicals segment, as well as our power generation and certain technology operations included in our Emerging Businesses segment, were transferred to Phillips 66. After the close of the New York Stock Exchange on April 30, 2012, the shareholders of record as of 5:00 p.m. Eastern time on April 16, 2012 (the Record Date), received one share of Phillips 66 common stock for every two ConocoPhillips common shares held as of the Record Date.

In connection with the separation, Phillips 66 distributed approximately $7.8 billion to us in a special cash distribution. These funds will be used solely to pay dividends, repurchase common stock, repay debt, or a combination of the foregoing, within twelve months following the distribution. At December 31, 2012, the unused amount of the special cash distribution was $748 million and is designated as Restricted cash on our consolidated balance sheet.

Significant Sources of Capital

Operating Activities

During 2012, cash provided by continuing operating activities was $13,458 million, a 4 percent decrease from 2011. During 2011, cash provided by continuing operations was $13,953 million compared with $14,013 million in 2010.

While the stability of our cash flows from operating activities benefits from geographic diversity, our short- and long-term operating cash flows are highly dependent upon prices for crude oil, bitumen, natural gas, LNG and natural gas liquids. Prices and margins in our industry are typically volatile, and are driven by market conditions over which we have no control. Absent other mitigating factors, as these prices and margins fluctuate, we would expect a corresponding change in our operating cash flows.

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

Our 2012 production from continuing operations averaged 1.527 million BOED. Future production is subject to numerous uncertainties, including, among others, the volatile crude oil and natural gas price environment, which may impact investment decisions; the effects of price changes on production sharing and variable-royalty contracts; timing of startups and major turnarounds; and weather-related disruptions. Our production from continuing operations in 2013 is expected to be 1.475 million to 1.525 million BOED.

To maintain or grow our production volumes, we must continue to add to our proved reserve base. Our total reserve replacement in 2012 was 142 percent. Excluding the impact of sales and purchases, the organic reserve replacement was 156 percent of 2012 production. Over the five-year period ended December 31, 2012, our reserve replacement was 48 percent (including 65 percent from consolidated operations) reflecting the disposition of our interest in LUKOIL and the impact of our asset disposition program. Excluding these items and purchases, our five-year organic reserve replacement was 108 percent. The total reserve replacement amount above is based on the sum of our net additions (revisions, improved recovery, purchases, extensions and discoveries, and sales) divided by our production, as shown in our reserve table disclosures. For additional information about our proved reserves, including both developed and undeveloped reserves, see the Oil and Gas Operations section of this report.

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

As discussed in the Critical Accounting Estimates section, engineering estimates of proved reserves are imprecise; therefore, each year reserves may be revised upward or downward due to the impact of changes in commodity prices or as more technical data becomes available on reservoirs. In 2012, 2011 and 2010, revisions increased reserves. It is not possible to reliably predict how revisions will impact reserve quantities in the future.

Asset Sales

Proceeds from asset sales in 2012 were $2,132 million, primarily from the sale of our Vietnam business, the sale of our equity interest in NMNG and the sale of our interest in the Statfjord and Alba fields in the North Sea. This compares with proceeds of $2,192 million in 2011, which mainly included the sale of our remaining interest in LUKOIL and certain properties located in the Lower 48. We have announced additional asset sales of $9.6 billion which are expected to close by mid-2013. We continue to evaluate opportunities to further optimize the portfolio.

Commercial Paper and Credit Facilities

In May 2012, we decreased our total revolving credit facilities from $8.0 billion to $7.5 billion by terminating all commitments under the $500 million credit facility, which was due to expire in July 2012. At

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December 31, 2012, we had a revolving credit facility totaling $7.5 billion expiring in August 2016. Our revolving credit facility may be used as direct bank borrowings, as support for issuances of letters of credit totaling up to $750 million, or as support for our commercial paper programs. The revolving credit 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 facility 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.

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 agreement calls for commitment fees on available, but unused, amounts. The agreement also contains early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

Our primary funding source for short-term working capital needs is the ConocoPhillips $6.35 billion commercial paper program. Commercial paper maturities are generally limited to 90 days. We also have the ConocoPhillips Qatar Funding Ltd. $1.15 billion commercial paper program, which is used to fund commitments relating to QG3. At December 31, 2012 and 2011, we had no direct borrowings under the revolving credit facilities, with no letters of credit issued at December 31, 2012, and $40 million at December 31, 2011. In addition, under the ConocoPhillips Qatar Funding Ltd. commercial paper program, $1,055 million of commercial paper was outstanding at December 31, 2012, compared with $1,128 million at December 31, 2011. Since we had $1,055 million of commercial paper outstanding and had issued no letters of credit, we had access to $6.4 billion in borrowing capacity under our revolving credit facilities at December 31, 2012.

Our senior long-term debt is rated A1 by Moody s Investors Service and A by both Standard and Poor s Rating Service and Fitch. We do not have any ratings triggers on any of our corporate debt that would cause an automatic default, and thereby impact our access to liquidity, in the event of a downgrade of our credit rating. If our credit rating were to deteriorate to a level prohibiting us from accessing the commercial paper market, we would still be able to access funds under our $7.5 billion revolving credit facility.

Certain of our project-related contracts and derivative instruments contain provisions that require us to post collateral. Cash is the primary source for providing collateral; however, many permit us to post letters of credit. At December 31, 2012, we had performance obligations secured by letters of credit of $852 million (issued as direct bank letters of credit) related to various purchase commitments for materials, supplies, commercial activities and services incident to the ordinary conduct of business.

Shelf Registration

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

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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.

For information about guarantees, see Note 13 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, 2012, was $21.7 billion, a decrease of $0.9 billion during 2012. During 2012, we repaid notes totaling $2.4 billion. We incurred a before-tax loss on redemption of $79 million, consisting of make-whole premiums and unamortized issuance costs. In December 2012, we issued $2.0 billion of new low-interest notes.

We are obligated to contribute $7.5 billion, plus interest, over a 10-year period that began in 2007, to FCCL. 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 $772 million was short-term and was included in the Accounts payable related parties line on our December 31, 2012, consolidated balance sheet. The principal portion of these payments, which totaled $733 million in 2012, is included in the Other line in the financing activities section of our consolidated statement of cash flows. Interest accrues at a fixed annual rate of 5.3 percent on the unpaid principal balance. Fifty percent of the quarterly interest payment is reflected as a capital contribution and is included in the Capital expenditures and investments line on our consolidated statement of cash flows.

In February, 2013, we announced a dividend of 66 cents per share. The dividend will be paid March 1, 2013, to stockholders of record at the close of business on February 19, 2013.

Since our share repurchase programs began in 2010, share repurchases totaled 300 million shares at a cost of $20.1 billion through December 31, 2012. Although we have no current plans for further share repurchases, we may do so opportunistically, contingent upon commodity prices and proceeds from asset dispositions.

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Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations of our continuing operations as of December 31, 2012:

		Millions of Dollars				
		Payments Due by Period				
		Total	Up to 1 Year	Years 2-3	Years 4-5	After 5 Years
Debt obligations (a)	$	21,709	955	1,952	3,274	15,528
Capital lease obligations		16	-	-	-	16
Total debt		21,725	955	1,952	3,274	15,544
Interest on debt and other obligations		16,355	1,247	2,216	1,964	10,928
Operating lease obligations		2,151	477	960	424	290
Purchase obligations (b)		26,465	12,149	4,370	2,242	7,704
Joint venture acquisition obligation (c)		3,582	772	1,672	1,138	-
Other long-term liabilities						
Pension and postretirement benefit contributions (d)		2,579	484	1,045	1,050	-
Asset retirement obligations*		9,033	387	521	413	7,712
Accrued environmental costs		364	38	65	48	213
Unrecognized tax benefits (e)		116	116	(e)	(e)	(e)
Total	$	82,370	16,625	12,801	10,553	42,391
**Excludes amounts related to discontinued operations:*	*$*	*131*	-	-	-	*131*

(a) Includes $429 million of net unamortized premiums and discounts. See Note 11 Debt, in the Notes to Consolidated Financial Statements, for additional information.

(b) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. Does not include purchase commitments for jointly owned fields and facilities where we are not the operator.
The majority of the purchase obligations are market-based contracts related to our commodity business. Product purchase commitments with third parties totaled $12,602 million.

Purchase obligations of $9,629 million are related to agreements to access and utilize the capacity of third-party equipment and facilities, including pipelines and LNG and product terminals, to transport, process, treat and store commodities. The remainder is primarily our net share of purchase commitments for materials and services for jointly owned fields and facilities where we are the operator.

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

(d)

Represents contributions to qualified and nonqualified pension and postretirement benefit plans for the years 2013 through 2017. For additional information related to expected benefit payments subsequent to 2017, see Note 19 Employee Benefit Plans, in the Notes to Consolidated Financial Statements.

(e) Excludes unrecognized tax benefits of $756 million because the ultimate disposition and timing of any payments to be made with regard to such amounts are not reasonably estimable. Although unrecognized tax benefits are not a contractual obligation, they are presented in this table because they represent potential demands on our liquidity.

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Capital Spending

Capital Program		Millions of Dollars		
		2012	2011	2010
Alaska	$	**828**	774	729
Lower 48 and Latin America		**5,251**	3,882	1,790
Canada		**2,184**	1,761	1,356
Europe		**2,860**	2,222	1,190
Asia Pacific and Middle East		**2,430**	2,325	2,157
Other International		**415**	8	127
LUKOIL Investment		**-**	-	-
Corporate and Other		**204**	242	186
Capital expenditures and investments from continuing operations		**14,172**	11,214	7,535
Discontinued operations in Kashagan, Nigeria and Algeria		**817**	1,038	1,071
Joint venture acquisition obligation (principal) Canada		**733**	695	659
Capital Program	$	**15,722**	12,947	9,265

Our capital expenditures and investments from continuing operations for the three-year period ended December 31, 2012, totaled $32.9 billion. The expenditures over this period supported key exploration and developments, primarily:

- Oil, natural gas liquids and natural gas developments in the Lower 48, including Texas, New Mexico, North Dakota, Oklahoma, Montana, Colorado, Wyoming and offshore in the Gulf of Mexico.
- Further development of coalbed methane (CBM) associated with the APLNG joint venture in Australia.
- Oil sands and ongoing natural gas developments in Canada.
- Alaska activities related to development in the Greater Kuparuk Area, the Greater Prudhoe Area, the Western North Slope and the Cook Inlet Area and initial development of the Point Thomson Unit.
- Development drilling and new facilities in the Norway sector of the North Sea, including the Greater Ekofisk Area, Alvheim, Visund and Statfjord, and Heidrun in the Norwegian Sea.
- The Bohai Bay development in China.
- In the U.K. sector of the North Sea, the development of the Jasmine discovery in the J-Area, the development of Clair Ridge and development drilling in the southern and central North Sea.
- The North Belut Field, as well as other developments in offshore Block B and onshore South Sumatra in Indonesia.
- QG3, an integrated development which produces and liquefies natural gas from Qatar s North Field.
- The Gumusut-Kakap development offshore Sabah, Malaysia.
- Exploration activities in Australia s Browse Basin, North American shale plays, Canadian oil sands developments, deepwater Gulf of Mexico, Alaska, the U.K. and Norway sectors of the North Sea, Kazakhstan and Indonesia.
- Leasehold acquisitions in Angola.

2013 CAPITAL PROGRAM

Our 2013 capital program of $15.8 billion is comprised of $15.0 billion for the capital expenditures and investments budget and $0.8 billion for principal contributions to fund our portion of the FCCL business venture. Of the $15.0 billion for the capital expenditures and investments budget, $0.3 billion relates to our discontinued operations in Kashagan, Nigeria and Algeria and $14.7 billion relates to continuing operations. Included in the 2013 capital expenditures and investments budget is $0.6 billion in capitalized interest.

Our 2013 capital expenditures and investments budget for continuing operations of $14.7 billion is 4 percent higher than actual expenditures in 2012.

We are directing approximately 60 percent of our 2013 capital expenditures and investments budget for continuing operations to North America. These funds are expected to be directed toward:

- In Alaska, further development of opportunities in Prudhoe Bay, Kuparuk and Alpine fields, and initial development of Point Thomson Field.
- In Lower 48, development of liquids-rich areas, such as the Eagle Ford trend, and the Williston and Permian basins.
- Exploration and appraisal activities in the Eagle Ford shale formation, and Avalon, Wolfcamp and Niobrara areas in Lower 48.
- Appraisal of deepwater Gulf of Mexico discoveries, wildcat wells and acreage additions.
- Liquids opportunities in the western Canada basins and Canadian oil sands.
- Exploration and appraisal activities in Canadian shale plays and oil sands.

We are directing approximately 40 percent of our 2013 capital expenditures and investments budget for continuing operations to Europe, Asia Pacific and other international businesses. These funds are expected to be directed toward:

- Further development of CBM associated with the APLNG joint venture in Australia.
- Elsewhere in the Asia Pacific and Middle East segment, continued development of Bohai Bay in China, new fields offshore Malaysia, and offshore Block B and onshore South Sumatra in Indonesia.
- In the North Sea, the Greater Ekofisk Area, development of the Jasmine discovery in the J-Block Area, development of Clair Ridge and the Britannia Long Term Compression Project.
- Onshore developments in Libya.
- Exploration and appraisal activities in Australia s offshore Browse Basin and onshore Canning Basin, deepwater Angola, offshore Indonesia and Malaysia, and the North Sea.

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

Contingencies

A number of lawsuits involving a variety of claims have been made against ConocoPhillips that arise in the ordinary course of business. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the case of income-tax-related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain.

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Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures. Estimates particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes. For information on other contingencies, see Note 14 Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Legal and Tax Matters

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, are required. See Note 20 Income Taxes, in the Notes to Consolidated Financial Statements, for additional information about income-tax-related contingencies.

Environmental

We are subject to the same numerous international, federal, state and local environmental laws and regulations as other companies in our industry. The most significant of these environmental laws and regulations include, among others, the:

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

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

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

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

An example is the use of hydraulic fracturing, an essential completion technique that facilitates production of oil and natural gas that is otherwise trapped in lower permeability rock formations. A range of local, state, federal or national laws and regulations currently govern hydraulic fracturing operations. Although hydraulic fracturing has been conducted for many decades, a number of new laws, regulations and permitting requirements are under consideration by the U.S. Environmental Protection Agency (EPA), the U.S. Department of the Interior, and others which could result in increased costs, operating restrictions, operational delays and/or limit the ability to develop oil and natural gas resources. Governmental restrictions on hydraulic fracturing could impact the overall profitability or viability of certain of our oil and natural gas investments. We have adopted operating principles that incorporate established industry standards designed to meet or exceed government requirements. Our practices continually evolve as technology improves and regulations change.

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. Longer-term expenditures are subject to considerable uncertainty and may fluctuate significantly.

We occasionally 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, 2011, we reported we had been notified of potential liability under CERCLA and comparable state laws at 74 sites around the United States. At December 31, 2012, we had closed 2 sites and transferred 61 sites to Phillips 66, bringing the number to 11 unresolved sites with potential liability.

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

Expensed environmental costs were $575 million in 2012 and are expected to be about $478 million per year in 2013 and 2014. Capitalized environmental costs were $297 million in 2012 and are expected to be about $459 million per year in 2013 and 2014.

Accrued liabilities for remediation activities are not reduced for potential recoveries from insurers or other third parties and are not discounted (except those assumed in a purchase business combination, which we do record on a discounted basis).

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

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

At December 31, 2012, our balance sheet included total accrued environmental costs of $364 million, and we expect to incur a substantial amount of these expenditures within the next 30 years. At December 31, 2011, accrued environmental costs were $922 million, of which $542 million related to the Downstream business.

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

Climate Change

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

- European Emissions Trading Scheme (ETS), the program through which many of the European Union (EU) member states are implementing the Kyoto Protocol. Our cost of compliance with the EU ETS in 2012 was approximately $10 million (pre-tax equity share).
- A regulation issued by the Alberta government in 2007 under the Climate Change and Emissions Act. The regulation requires 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 beginning July 1, 2007 by 12 percent. New facilities must reduce 2 percent per year until they reach the maximum target of 12 percent. We also incur a carbon tax for emissions from fossil fuel combustion in our British Columbia operations. The total cost of compliance with these Canadian regulations in 2012 was approximately $7 million.

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- The U.S. Supreme Court decision in Massachusetts v. EPA, 549 U.S. 497, 127 S.Ct. 1438 (2007), confirming that the EPA has the authority to regulate carbon dioxide as an air pollutant under the Federal Clean Air Act.
- The EPA s announcement on March 29, 2010 (published as Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs, 75 Fed. Reg. 17004 (April 2, 2010)), and the EPA s and U.S. Department of Transportation s joint promulgation of a Final Rule on April 1, 2010, that triggers regulation of GHGs under the Clean Air Act, may trigger more climate-based claims for damages, and may result in longer agency review time for development projects.
- Carbon taxes in certain jurisdictions. Our cost of compliance with Norwegian carbon tax legislation in 2012 was approximately $20 million (equity share pre-tax). In October 2012 the Norwegian government announced a doubling of the carbon tax for oil and gas production in 2013. Cap and trade programs in certain jurisdictions, including the Australian Clean Energy Legislation which took effect from July 2012. Our annual cost of compliance with the Australian Clean Energy Legislation during the initial fixed price phase is approximately $10 million (equity share pre-tax).

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

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

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

The Company has responded by putting in place a corporate Climate Change Action Plan, together with individual business unit climate change management plans in order to undertake actions in four major areas:

- Equipping the Company for a low emission world, for example by integrating GHG forecasting and reporting into company procedures; utilizing GHG pricing in planning economics; developing systems to handle GHG market transactions.
- Reducing GHG emissions In 2011 the Company reduced GHG emissions by 600,000 tonnes by carrying out a range of programs across a number of business units.
- Evaluating business opportunities such as the creation of offsets and allowances; carbon capture and storage; the use of low carbon energy and the development of low carbon technologies.
- Engaging externally The Company is a sponsor of MIT s Joint Program on the Science and Policy of Global Change; constructively engages in the development of climate change legislation and regulation; and discloses our progress and performance through the Carbon Disclosure Project and the Dow Jones Sustainability Index.

The Company uses an estimated market cost of GHG emissions in the range of $8 to $46 per tonne depending on the timing and country or region to evaluate future opportunities.

Other

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

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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 there is a reasonable likelihood 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 2012, 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 $1,915 million and the accumulated impairment reserve was $517 million. The weighted-average judgmental percentage probability of ultimate failure was approximately 46 percent, and the weighted-average amortization period was approximately four years. If that judgmental percentage were to be raised by 5 percent across all calculations, pretax leasehold impairment expense in 2013 would increase by approximately $30 million. At year-end 2012, the remaining $6,576 million of gross capitalized unproved property costs consisted of individually significant leaseholds, mineral rights held in perpetuity by title ownership, exploratory wells currently being drilled, suspended exploratory wells, and capitalized interest. Management periodically assesses individually significant leaseholds for impairment based on the results of exploration and drilling efforts and the outlook for commercialization. Of this amount, approximately $3 billion is concentrated in 10 major development areas. These major assets are not expected to move to proved properties in 2013.

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.

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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 development economically profitable. Often, the ability to move into the development phase and record proved reserves is dependent on obtaining permits and government or co-venturer approvals, the timing of which is ultimately beyond our control. Exploratory well costs remain suspended as long as we are actively pursuing such approvals and permits, and believe they will be obtained. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved reserves. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field or while we seek government or co-venturer approval of development plans or seek environmental permitting. Once a determination is made the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and reported in exploration expense.

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

At year-end 2012, total suspended well costs were $1,038 million, compared with $1,037 million at year-end 2011. For additional information on suspended wells, including an aging analysis, see Note 7 Suspended Wells, in the Notes to Consolidated Financial Statements.

Proved Reserves

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

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

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

Our proved reserves include estimated quantities related to production sharing contracts, which are reported under the economic interest method and are subject to fluctuations in commodity prices; recoverable operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices increase, then our applicable reserve quantities would decline. The estimation of proved developed reserves also is important to the income statement because the proved developed reserve estimate for a field serves as the denominator in the unit-of-production calculation of the DD&A of the capitalized costs for that asset. At year-end 2012, the net book value of productive properties, plants and equipment (PP&E) subject to a unit-of-production calculation was approximately $55 billion and the DD&A recorded on these assets in 2012 was approximately $6.4 billion. The estimated proved developed reserves for our consolidated operations were 5.1 billion BOE at the end of 2011 and 4.9 billion BOE at the end of 2012. If the estimates of proved reserves used in the unit-of-production calculations had been lower by 5 percent across all calculations, pretax DD&A in 2012 would have increased by an estimated $336 million.

Impairments

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows expected to be generated by an asset group and annually in the fourth quarter following updates to corporate planning assumptions. If there is an indication the carrying amount of an asset may not be recovered, the asset is monitored by management through an established process where changes to significant assumptions such as prices, volumes and future development plans are reviewed. 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. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. The expected future cash flows used for impairment reviews and related fair value calculations are based on judgmental assessments of future production volumes, commodity prices, operating costs and capital decisions, considering all available information at the date of review. See Note 9 Impairments, in the Notes to Consolidated Financial Statements, for additional information.

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

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 plugging and abandonment of wells, removal and disposal of offshore oil and gas platforms around the world, as well as oil and gas production facilities and pipelines in Alaska. The fair values of obligations for dismantling and removing these facilities are accrued into PP&E at the time of installation of the asset based on estimated discounted costs. Estimating the future asset removal costs necessary for this accounting calculation is difficult. Most of these removal obligations are many years, or decades, in the future and the contracts and regulations often have vague descriptions of what removal practices and criteria must be met when the removal event actually occurs. Asset removal technologies and costs, regulatory and other

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compliance considerations, expenditure timing, and other inputs into valuation of the obligation, including discount and inflation rates, are also subject to change.

Normally, changes in asset removal obligations are reflected in the income statement as increases or decreases to DD&A over the remaining life of the assets. However, for assets at or nearing the end of their operations, as well as previously sold assets for which we retained the asset removal obligation, an increase in the asset removal obligation can result in an immediate charge to earnings, because any increase in PP&E due to the increased obligation would immediately be subject to impairment, due to the low fair value of these properties.

In addition to asset removal obligations, under the above or similar contracts, permits and regulations, we have certain environmental-related projects. These are primarily related to remediation activities required by Canada and various states within the United States 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.

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. The actuarial determination of projected benefit obligations and company contribution requirements involves judgment about uncertain future events, including estimated retirement dates, salary levels at retirement, mortality rates, lump-sum election rates, rates of return on plan assets, future health care cost-trend rates, and rates of utilization of health care services by retirees. Due to the specialized nature of these calculations, we engage outside actuarial firms to assist in the determination of these projected benefit obligations and company contribution requirements. For Employee Retirement Income Security Act-qualified pension plans, the actuary exercises fiduciary care on behalf of plan participants in the determination of the judgmental assumptions used in determining required company contributions into the plan. Due to differing objectives and requirements between financial accounting rules and the pension plan funding regulations promulgated by governmental agencies, the actuarial methods and assumptions for the two purposes differ in certain important respects. Ultimately, we will be required to fund all promised benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Benefit expense is particularly sensitive to the discount rate and return on plan assets assumptions. A 1 percent decrease in the discount rate assumption would increase annual benefit expense by $130 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $50 million. In determining the discount rate, we use yields on high-quality fixed income investments matched to the estimated benefit cash flows of our plans. We are also exposed to the possibility that lump sum retirement benefits taken from pension plans during the year could exceed the total of service and interest components of annual pension expense and trigger accelerated recognition of a portion of unrecognized net actuarial losses and gains. These benefit payments are based on decisions by plan participants and are therefore difficult to predict.

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

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

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

- Fluctuations in crude oil, bitumen, natural gas, LNG and natural gas liquids prices.
- Potential failures or delays in achieving expected reserve or production levels from existing and future oil and gas developments due to operating hazards, drilling risks and the inherent uncertainties in predicting reserves and reservoir performance.
- Unsuccessful exploratory drilling activities or the inability to obtain access to exploratory acreage.
- Unexpected changes in costs or technical requirements for constructing, modifying or operating exploration and production facilities.
- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, natural gas, natural gas liquids, bitumen and LNG.
- Inability to timely obtain or maintain permits, including those necessary for drilling and/or development, 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 exploration and production and LNG development.
- Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, political events, terrorism or cyber attacks.
- International monetary conditions and exchange controls.
- Substantial investment or reduced demand for products as a result of existing or future environmental rules and regulations.
- Liability for remedial actions, including removal and reclamation obligations, under environmental regulations.
- Liability resulting from litigation.
- General domestic and international economic and political developments, including armed hostilities; expropriation of assets; changes in governmental policies relating to crude oil, bitumen, natural gas, LNG or natural gas liquids pricing, regulation or taxation; other political, economic or diplomatic developments; and international monetary fluctuations.
- Changes in tax and other laws, regulations (including alternative energy mandates), or royalty rules applicable to our business.
- Limited access to capital or significantly higher cost of capital related to illiquidity or uncertainty in the domestic or international financial markets.
- Delays in, or our inability to implement, our asset disposition plan.
- Inability to obtain economical financing for development, construction or modification of facilities and general corporate purposes.
- The operation and financing of our joint ventures.
- The factors generally described in Item 1A Risk Factors in this report.

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Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Financial Instrument Market Risk

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

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

Commodity Price Risk

Our Commercial organization uses futures, forwards, swaps and options in various markets to accomplish the following objectives:

- 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 consumers, to floating market prices.
- Enable us to use the market knowledge gained from these activities to capture market opportunities such as moving physical commodities to more profitable locations and storing commodities to capture seasonal or time premiums. We may use derivatives to optimize these activities.

We use a VaR model to estimate the loss in fair value that could potentially result on a single day from the effect of adverse changes in market conditions on the derivative financial instruments and derivative commodity instruments we hold or issue, including commodity purchases and sales contracts recorded on the balance sheet at December 31, 2012, as derivative instruments. Using Monte Carlo simulation, a 95 percent confidence level and a one-day holding period, the VaR for those instruments issued or held for trading purposes at December 31, 2012 and 2011, was immaterial to our consolidated cash flows and net income attributable to ConocoPhillips. The VaR for instruments held for purposes other than trading at December 31, 2012 and 2011, was also immaterial to our cash flows and net income attributable to ConocoPhillips.

Interest Rate Risk

The following table provides information about our financial instruments that are sensitive to changes in U.S. interest rates. The debt portion of the table presents principal cash flows and related weighted-average interest rates by expected maturity dates. Weighted-average variable rates are based on effective rates at the reporting date. The carrying amount of our floating-rate debt approximates its fair value. The fair value of the fixed-rate financial instruments is estimated based on quoted market prices. The joint venture acquisition obligation portion of the table presents principal cash flows of the fixed-rate 5.3 percent joint venture acquisition obligation owed to FCCL Partnership. The fair value of the obligation is estimated based on the net present value of the future cash flows, discounted at year-end 2012 and 2011 effective yield rates of 0.7 percent and 1.24 percent, respectively, based on yields of U.S. Treasury securities of a similar average duration adjusted for ConocoPhillips average credit risk spread and the amortizing nature of the obligation principal.

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	Millions of Dollars Except as Indicated					
	Debt				Joint Venture Acquisition Obligation	
Expected Maturity Date	Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Average Interest Rate	Fixed Rate Maturity	Average Interest Rate
Year-End 2012						
2013	**$ 850**	**5.75 %**	**$ 91**	**0.25 %**	**$ 772**	**5.30%**
2014	**400**	**4.75**	**-**	**-**	**814**	**5.30**
2015	**1,500**	**4.60**	**-**	**-**	**858**	**5.30**
2016	**1,273**	**5.52**	**964**	**0.25**	**904**	**5.30**
2017	**1,001**	**1.06**	**-**	**-**	**234**	**5.30**
Remaining years	**14,918**	**6.25**	**283**	**0.19**	**-**	**5.30**
Total	**$ 19,942**		**$ 1,338**		**$ 3,582**	
Fair value	**$ 25,011**		**$ 1,338**		**$ 3,968**	
Year-End 2011						
2012	$ 918	4.80 %	$ 3	0.38 %	$ 732	5.30%
2013	1,262	5.33	-	-	772	5.30
2014	1,511	4.77	-	-	814	5.30
2015	1,513	4.62	15	2.01	858	5.30
2016	1,287	5.54	1,128	0.51	904	5.30
Remaining years	14,008	6.52	498	0.38	234	5.30
Total	$ 20,499		$ 1,644		$ 4,314	
Fair value	$ 25,421		$ 1,644		$ 4,820	

Foreign Currency Exchange Risk

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

At December 31, 2012 and 2011, we held foreign currency exchange forwards hedging cross-border commercial activity and foreign currency exchange swaps for purposes of mitigating our cash related exposures. Although these forwards and swaps hedge exposures to fluctuations in exchange rates, we elected not to utilize hedge accounting. As a result, the change in the fair value of these foreign currency exchange derivatives is recorded directly in earnings. Since the gain or loss on the swaps is offset by the gain or loss from remeasuring the related cash balances, and since our aggregate position in the forwards was not material, there would be no material impact to our income from an adverse hypothetical 10 percent change in the December 31, 2012, or 2011, exchange rates. The notional and fair market values of these positions at December 31, 2012 and 2011, were as follows:

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Foreign Currency Exchange Derivatives		In Millions			
		Notional*		Fair Market Value**	
		2012	2011	**2012**	2011
Sell U.S. dollar, buy euro	USD	**-**	219	**$ -**	(8)
Sell U.S. dollar, buy British pound	USD	**2,573**	790	**31**	-
Sell U.S. dollar, buy Canadian dollar	USD	**-**	648	**-**	-
Sell U.S. dollar, buy Norwegian krone	USD	**-**	292	**-**	(7)
Buy U.S. dollar, sell euro	USD	**7**	-	**-**	-
Buy U.S. dollar, sell Norwegian krone	USD	**90**	-	**-**	-
Buy U.S. dollar, sell Canadian dollar	USD	**43**	-	**(2)**	-
Buy euro, sell Norwegian krone	EUR	**-**	3	**-**	-
Buy euro, sell British pound	EUR	**96**	-	**-**	-
Sell euro, buy British pound	EUR	**-**	64	**-**	5

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

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

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

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONOCOPHILLIPS

INDEX TO FINANCIAL STATEMENTS

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Report of Management

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

Assessment of Internal Control Over Financial Reporting

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

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

Management assessed the effectiveness of the company s internal control over financial reporting as of December 31, 2012. 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, 2012.

Ernst & Young LLP has issued an audit report on the company s internal control over financial reporting as of December 31, 2012, and their report is included herein.

/s/ Ryan M. Lance

Ryan M. Lance
Chairman and
Chief Executive Officer
February 19, 2013

/s/ Jeff W. Sheets

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

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Report of Independent Registered Public Accounting Firm on Consolidated Financial Statements

The Board of Directors and Stockholders

ConocoPhillips

We have audited the accompanying consolidated balance sheets of ConocoPhillips as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the related condensed consolidating financial information listed in the Index at Item 8 and financial statement schedule listed in Item 15(a). These financial statements, condensed consolidating financial information, and schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements, condensed consolidating financial information, and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of ConocoPhillips at December 31, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, 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.

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, 2012, 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 19, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 19, 2013

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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, 2012, 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, 2012, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2012 consolidated financial statements of ConocoPhillips and our report dated February 19, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 19, 2013

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Consolidated Income Statement **ConocoPhillips**

Years Ended December 31		Millions of Dollars		
		2012	2011	2010
Revenues and Other Income				
Sales and other operating revenues	$	**57,967**	64,196	56,215
Equity in earnings of affiliates		**1,911**	1,239	1,376
Gain on dispositions		**1,657**	370	5,563
Other income		**469**	264	181
Total Revenues and Other Income		**62,004**	66,069	63,335
Costs and Expenses				
Purchased commodities		**25,232**	29,797	24,854
Production and operating expenses		**6,793**	6,426	6,227
Selling, general and administrative expenses		**1,106**	865	809
Exploration expenses		**1,500**	1,038	1,125
Depreciation, depletion and amortization		**6,580**	6,827	8,004
Impairments		**680**	321	81
Taxes other than income taxes		**3,546**	3,999	2,788
Accretion on discounted liabilities		**394**	422	409
Interest and debt expense		**709**	954	1,167
Foreign currency transaction (gains) losses		**41**	24	(4)
Total Costs and Expenses		**46,581**	50,673	45,460
Income from continuing operations before income taxes		**15,423**	15,396	17,875
Provision for income taxes		**7,942**	8,208	7,570
Income From Continuing Operations		**7,481**	7,188	10,305
Income from discontinued operations*		**1,017**	5,314	1,112
Net income		**8,498**	12,502	11,417
Less: net income attributable to noncontrolling interests		**(70)**	(66)	(59)
Net Income Attributable to ConocoPhillips	$	**8,428**	12,436	11,358
Amounts Attributable to ConocoPhillips Common Shareholders:				
Income from continuing operations	$	**7,413**	7,127	10,251
Income from discontinued operations		**1,015**	5,309	1,107
Net Income	$	**8,428**	12,436	11,358
Net Income Attributable to ConocoPhillips Per Share of Common Stock *(dollars)*				
Basic				
Continuing operations	$	**5.95**	5.18	6.93
Discontinued operations		**0.82**	3.86	0.75
Net Income Attributable to ConocoPhillips Per Share of Common Stock	$	**6.77**	9.04	7.68

Diluted				
Continuing operations	$	**5.91**	5.14	6.88
Discontinued operations		**0.81**	3.83	0.74
Net Income Attributable to ConocoPhillips Per Share of Common Stock	$	**6.72**	8.97	7.62
Dividends Paid Per Share of Common Stock *(dollars)*	$	**2.64**	2.64	2.15
Average Common Shares Outstanding *(in thousands)*				
Basic		**1,243,799**	1,375,035	1,479,330
Diluted		**1,253,093**	1,387,100	1,491,067
**Net of provision for income taxes on discontinued operations of:*	*$*	***745***	*2,291*	*763*

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Comprehensive Income **ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2012	2011	2010
Net Income	$ **8,498**	12,502	11,417
Other comprehensive income			
Defined benefit plans			
Prior service cost (credit) arising during the period	**2**	19	(13)
Reclassification adjustment for amortization of prior service cost (credit) included in net income	**(5)**	2	15
Net change	**(3)**	21	2
Net actuarial loss arising during the period	**(704)**	(1,185)	(9)
Reclassification adjustment for amortization of net actuarial losses included in net income	**430**	226	215
Net change	**(274)**	(959)	206
Nonsponsored plans*	**8**	(50)	5
Income taxes on defined benefit plans	**132**	375	(67)
Defined benefit plans, net of tax	**(137)**	(613)	146
Unrealized holding gain on securities**	**-**	8	631
Reclassification adjustment for gain included in net income	**-**	(255)	(384)
Income taxes on unrealized holding gain on securities	**-**	89	(89)
Unrealized gain (loss) on securities, net of tax	**-**	(158)	158
Foreign currency translation adjustments	**929**	(387)	1,417
Reclassification adjustment for gain included in net income	**(155)**	(516)	-
Income taxes on foreign currency translation adjustments	**(16)**	(14)	(13)
Foreign currency translation adjustments, net of tax	**758**	(917)	1,404
Hedging activities	**6**	1	-
Income taxes on hedging activities	**-**	-	-
Hedging activities, net of tax	**6**	1	-
Other Comprehensive Income (Loss), Net of Tax	**627**	(1,687)	1,708
Comprehensive Income	**9,125**	10,815	13,125
Less: comprehensive income attributable to noncontrolling interests	**(70)**	(66)	(59)
Comprehensive Income Attributable to ConocoPhillips	$ **9,055**	10,749	13,066

**Plans for which ConocoPhillips is not the primary obligor primarily those administered by equity affiliates.*

***Available-for-sale securities of LUKOIL.*

See Notes to Consolidated Financial Statements.

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Consolidated Balance Sheet **ConocoPhillips**

At December 31		Millions of Dollars	
		2012	2011
Assets			
Cash and cash equivalents	$	**3,618**	5,780
Short-term investments*		**-**	581
Restricted cash		**748**	-
Accounts and notes receivable (net of allowance of $10 million in 2012 and $30 million in 2011)		**8,929**	14,648
Accounts and notes receivable related parties		**253**	1,878
Inventories		**965**	4,631
Prepaid expenses and other current assets		**9,476**	2,700
Total Current Assets		**23,989**	30,218
Investments and long-term receivables		**23,489**	32,108
Loans and advances related parties		**1,517**	1,675
Net properties, plants and equipment (net of accumulated depreciation, depletion and amortization of $58,916 million in 2012 and $65,029 million in 2011)		**67,263**	84,180
Goodwill		**-**	3,332
Intangibles		**4**	745
Other assets		**882**	972
Total Assets	$	**117,144**	153,230
Liabilities			
Accounts payable	$	**9,154**	17,973
Accounts payable related parties		**859**	1,680
Short-term debt		**955**	1,013
Accrued income and other taxes		**3,366**	4,220
Employee benefit obligations		**742**	1,111
Other accruals		**2,367**	2,071
Total Current Liabilities		**17,443**	28,068
Long-term debt		**20,770**	21,610
Asset retirement obligations and accrued environmental costs		**8,947**	9,329
Joint venture acquisition obligation related party		**2,810**	3,582
Deferred income taxes		**13,185**	18,040
Employee benefit obligations		**3,346**	4,068
Other liabilities and deferred credits		**2,216**	2,784
Total Liabilities		**68,717**	87,481
Equity			
Common stock (2,500,000,000 shares authorized at $.01 par value)			
Issued (2012 1,762,247,949 shares; 2011 1,749,550,587)			
Par value		**18**	17
Capital in excess of par		**45,324**	44,725
Treasury stock (at cost: 2012 542,230,673; 2011 463,880,628)		**(36,780)**	(31,787)
Accumulated other comprehensive income		**4,087**	3,246
Unearned employee compensation		**-**	(11)
Retained earnings		**35,338**	49,049
Total Common Stockholders Equity		**47,987**	65,239

Noncontrolling interests		**440**	510
Total Equity		**48,427**	65,749
Total Liabilities and Equity	**$**	**117,144**	153,230
**Includes marketable securities of:*	*$*	**-**	*232*

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Cash Flows **ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2012	2011	2010
Cash Flows From Operating Activities			
Net income	$ **8,498**	12,502	11,417
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	**6,580**	6,827	8,004
Impairments	**680**	321	81
Dry hole costs and leasehold impairments	**874**	469	476
Accretion on discounted liabilities	**394**	422	409
Deferred taxes	**1,397**	340	(973)
Undistributed equity earnings	**(596)**	(131)	(357)
Gain on dispositions	**(1,657)**	(370)	(5,563)
Income from discontinued operations	**(1,017)**	(5,314)	(1,112)
Other	**(456)**	(403)	(371)
Working capital adjustments			
Decrease (increase) in accounts and notes receivable	**(1,866)**	(938)	324
Decrease (increase) in inventories	**210**	(81)	(43)
Decrease (increase) in prepaid expenses and other current assets	**513**	(300)	150
Increase (decrease) in accounts payable	**1,103**	1,297	(18)
Increase (decrease) in taxes and other accruals	**(1,199)**	(688)	1,589
Net cash provided by continuing operating activities	**13,458**	13,953	14,013
Net cash provided by discontinued operations	**464**	5,693	3,032
Net Cash Provided by Operating Activities	**13,922**	19,646	17,045
Cash Flows From Investing Activities			
Capital expenditures and investments	**(14,172)**	(11,214)	(7,535)
Proceeds from asset dispositions	**2,132**	2,192	14,710
Net sales (purchases) of short-term investments	**597**	400	(982)
Long-term advances/loans related parties	**-**	-	(118)
Collection of advances/loans related parties	**114**	98	95
Other	**821**	50	218
Net cash provided by (used in) continuing investing activities	**(10,508)**	(8,474)	6,388
Net cash provided by (used in) discontinued operations	**(1,119)**	1,459	(1,723)
Net Cash Provided by (Used in) Investing Activities	**(11,627)**	(7,015)	4,665
Cash Flows From Financing Activities			
Issuance of debt	**1,996**	-	118
Repayment of debt	**(2,565)**	(934)	(5,294)
Special cash distribution from Phillips 66	**7,818**	-	-
Change in restricted cash	**(748)**	-	-
Issuance of company common stock	**138**	96	133
Repurchase of company common stock	**(5,098)**	(11,123)	(3,866)
Dividends paid	**(3,278)**	(3,632)	(3,175)
Other	**(725)**	(684)	(706)
Net cash used in continuing financing activities	**(2,462)**	(16,277)	(12,790)
Net cash used in discontinued operations	**(2,019)**	(28)	(29)

Net Cash Used in Financing Activities		**(4,481)**	(16,305)	(12,819)
Effect of Exchange Rate Changes on Cash and Cash Equivalents		**24**	-	21
Net Change in Cash and Cash Equivalents		**(2,162)**	(3,674)	8,912
Cash and cash equivalents at beginning of period		**5,780**	9,454	542
Cash and Cash Equivalents at End of Period	**$**	**3,618**	5,780	9,454

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Changes in Equity **ConocoPhillips**

	Millions of Dollars								
	Attributable to ConocoPhillips								
	Common Stock								
	Par Value	Capital in Excess of Par	Treasury Stock	Grantor Trusts	Accum. Other Comprehensive Income (Loss)	Unearned Employee Compensation	Retained Earnings	Non-Controlling Interests	Total
December 31, 2009	$ 17	43,681	(16,211)	(667)	3,225	(76)	32,069	590	62,628
Net income							11,358	59	11,417
Other comprehensive income					1,708				1,708
Dividends paid							(3,175)		(3,175)
Repurchase of company common stock			(3,866)						(3,866)
Distributions to noncontrolling interests and other								(102)	(102)
Distributed under benefit plans		451		34					485
Recognition of unearned compensation						29			29
December 31, 2010	$ 17	44,132	(20,077)	(633)	4,933	(47)	40,252	547	69,124
Net income							12,436	66	12,502
Other comprehensive loss					(1,687)				(1,687)
Dividends paid							(3,632)		(3,632)
Repurchase of company common stock			(11,133)	10					(11,123)
Distributions to noncontrolling interests and other								(103)	(103)
Distributed under benefit plans		593	33	13					639
Recognition of unearned compensation						36			36
Transfer to Treasury Stock			(610)	610					-
Other							(7)		(7)
December 31, 2011	$ 17	44,725	(31,787)	-	3,246	(11)	49,049	510	65,749
Net income							**8,428**	**70**	**8,498**
Other comprehensive income					**627**				**627**
Dividends paid							**(3,278)**		**(3,278)**
Repurchase of company common stock			**(5,098)**						**(5,098)**
Distributions to noncontrolling interests and other								**(109)**	**(109)**
Distributed under benefit plans	**1**	**599**	**105**						**705**
Recognition of unearned compensation						**11**			**11**
Separation of Downstream business					**214**		**(18,880)**	**(31)**	**(18,697)**
Other							**19**		**19**
December 31, 2012	**$ 18**	**45,324**	**(36,780)**	**-**	**4,087**	**-**	**35,338**	**440**	**48,427**

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. When we do not have the ability to exert significant influence, the investment is either classified as available-for-sale if fair value is readily determinable, or the cost method is used if fair value is not readily determinable. Undivided interests in oil and gas joint ventures, pipelines, natural gas plants and terminals are consolidated on a proportionate basis. Other securities and investments are generally carried at cost.

As a result of our separation of Phillips 66 on April 30, 2012, the results of operations for our former refining, marketing and transportation businesses; most of our former Midstream segment; our former Chemicals segment; and our power generation and certain technology operations included in our former Emerging Businesses segment (collectively, our Downstream business), have been classified as discontinued operations for all periods presented. In addition, the results of operations for our interest in the North Caspian Sea Production Sharing Agreement (Kashagan) and our Algerian and Nigerian businesses have been classified as discontinued operations for all periods presented. See Note 2 Discontinued Operations, for additional information. We have also realigned our reporting segments following the separation of Phillips 66 and have reflected those changes for all periods presented. We manage our operations through six operating segments, defined by geographic region: Alaska, Lower 48 and Latin America, Canada, Europe, Asia Pacific and Middle East, and Other International. For additional information, see Note 25 Segment Disclosures and Related Information. Unless indicated otherwise, the information in the Notes to the Consolidated Financial Statements relates to our continuing operations.

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

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

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

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

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

- **Shipping and Handling Costs** We include shipping and handling costs in production and operating expenses for production activities. Transportation costs related to marketing activities are recorded in purchased commodities. Freight costs billed to customers were recorded as a component of revenue.

- **Cash Equivalents** Cash equivalents are highly liquid, short-term investments that are readily convertible to known amounts of cash and have original maturities of 90 days or less from their date of purchase. They are carried at cost plus accrued interest, which approximates fair value.

- **Short-Term Investments** Investments in bank time deposits and marketable securities (commercial paper and government obligations) with original maturities of greater than 90 days but less than one year are classified as short-term investments. See Note 15 Derivative and Financial Instruments, for additional information on these held-to-maturity financial instruments.

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

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

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

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

- **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 (PP&E). Leasehold impairment is recognized based on exploratory experience and management s judgment. Upon achievement of all conditions necessary for reserves to be classified as proved, the associated leasehold costs are reclassified to proved properties.

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

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as dry holes when it judges the potential field does not warrant further investment in the near term. See Note 7 Suspended Wells, for additional information on suspended wells.

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

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

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

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

- **Goodwill** Goodwill resulting from a business combination is not amortized but is tested at least annually for impairment. If the fair value of a reporting unit is less than the recorded book value of the reporting unit s assets (including goodwill), less liabilities, then a hypothetical purchase price allocation is performed on the reporting unit s assets and liabilities using the fair value of the reporting unit as the purchase price in the calculation. If the amount of goodwill resulting from this hypothetical purchase price allocation is less than the recorded amount of goodwill, the recorded goodwill is written down to the new amount. At December 31, 2011, the Company s remaining goodwill resided in its discontinued Downstream business and had been evaluated for impairment on a worldwide basis.

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

- **Impairment of Properties, Plants and Equipment** PP&E used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group and annually in the fourth quarter following updates to corporate planning assumptions. If there is an indication the carrying amount of an asset may not be recovered, the asset is monitored by management through an established process where changes to significant assumptions such as prices, volumes and future development plans are reviewed. If, upon review, the sum of the undiscounted pre-tax 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. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. Long-lived assets committed by management for disposal within one year are accounted for at the lower of amortized cost or fair value, less cost to sell, with fair value determined using a binding negotiated price, if available, or present value of expected future cash flows as previously described.

The expected future cash flows used for impairment reviews and related fair value calculations are based on estimated future production volumes, prices and costs, considering all available evidence at the date of review. 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.

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

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

- **Property Dispositions** When complete units of depreciable property are sold, the asset cost and related accumulated depreciation are eliminated, with any gain or loss reflected in the Gain on dispositions line of our consolidated income statement. 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** The fair value of legal obligations to retire and remove long-lived assets are recorded in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize this cost by increasing the carrying amount of the related PP&E. If, in subsequent periods, our estimate of this liability changes, we will record an adjustment to both the liability and PP&E. Over time the liability is increased for the change in its present value, and the capitalized cost in PP&E is depreciated over the useful life of the related asset. For additional information, see Note 10 Asset Retirement Obligations and Accrued Environmental Costs, for additional information.

Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures relating to an existing condition caused by past operations, and those having no 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 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 indicating 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** We recognize stock-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award) or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement. We have elected to recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

- **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 and debt expense, and penalties related to unrecognized tax benefits are reflected in production and operating expenses.

- **Taxes Collected from Customers and Remitted to Governmental Authorities** Sales and value-added taxes are recorded net in taxes other than income taxes.

- **Net Income Per Share of Common Stock** Basic net 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 yet been issued as common stock,

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along with an adjustment to net income for dividend equivalents paid on unvested unit awards that are considered participating securities. Diluted net income per share of common stock includes 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, primarily under the treasury-stock method. Treasury stock and shares held by grantor trusts are excluded from the daily weighted-average number of common shares outstanding in both calculations. The earnings per share impact of the participating securities is immaterial.

Note 2 Discontinued Operations

Separation of Downstream Business

On April 30, 2012, the separation of our Downstream business was completed, creating two independent energy companies: ConocoPhillips and Phillips 66. After the close of the New York Stock Exchange on April 30, 2012, the shareholders of record as of 5:00 p.m. Eastern time on April 16, 2012 (the Record Date), received one share of Phillips 66 common stock for every two ConocoPhillips common shares held as of the Record Date.

In connection with the separation, Phillips 66 distributed approximately $7.8 billion to us in a special cash distribution, primarily using the proceeds from the $5.8 billion in Senior Notes issued by Phillips 66 in March 2012, as well as a portion of the approximately $3.6 billion in cash transferred to Phillips 66 at separation, comprised of funds received from the $2.0 billion term loan entered into by Phillips 66 immediately prior to the separation, and approximately $1.6 billion of cash held by Phillips 66 subsidiaries. Pursuant to the private letter ruling from the Internal Revenue Service, the principal funds from the special cash distribution will be used solely to pay dividends, repurchase common stock, repay debt, or a combination of the foregoing, within twelve months following the distribution. At December 31, 2012, the remaining balance of the cash distribution was $748 million and was included in the Restricted cash line on our consolidated balance sheet.

In order to effect the separation and govern our relationship with Phillips 66 after the separation, we entered into a Separation and Distribution Agreement, an Indemnification and Release Agreement, an Intellectual Property Assignment and License Agreement, a Tax Sharing Agreement, an Employee Matters Agreement and a Transition Services Agreement. The Separation and Distribution Agreement governs the separation of the Downstream business, the transfer of assets and other matters related to our relationship with Phillips 66. The Indemnification and Release Agreement provides for cross-indemnities between Phillips 66 and us and established procedures for handling claims subject to indemnification and related matters. The Intellectual Property Assignment and License Agreement governs the allocation of intellectual property rights and assets between Phillips 66 and us.

The Tax Sharing Agreement governs the respective rights, responsibilities and obligations of Phillips 66 and ConocoPhillips with respect to taxes, tax attributes, tax returns, tax proceedings and certain other tax matters. In addition, the Tax Sharing Agreement imposed certain restrictions on Phillips 66 and its subsidiaries (including restrictions on share issuances, business combinations, sales of assets and similar transactions) that are designed to preserve the tax-free status of the distribution and certain related transactions. The Tax Sharing Agreement sets forth the obligations of Phillips 66 and us as to the filing of tax returns, the administration of tax proceedings and assistance and cooperation on tax matters.

The Employee Matters Agreement governs the compensation and employee benefit obligations with respect to the current and former employees and non-employee directors of Phillips 66 and ConocoPhillips, and generally allocates liabilities and responsibilities relating to employee compensation, benefit plans and programs. The Employee Matters Agreement provides that employees of Phillips 66 will no longer participate in benefit plans sponsored or maintained by ConocoPhillips. In addition, the Employee Matters Agreement provides that each of the parties will be responsible for their respective current employees and compensation plans for such current employees, and we will be responsible for liabilities relating to former employees who left prior to the separation (other than in certain instances where a plan or program was sponsored by a company that became part of the Phillips 66 group of companies at the separation). The Employee Matters

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Agreement sets forth the general principles relating to employee matters and also addresses any special circumstances during the transition period. The Employee Matters Agreement also provides that (i) the distribution does not constitute a change in control under existing plans, programs, agreements or arrangements, and (ii) the distribution and the assignment, transfer or continuation of the employment of employees with another entity will not constitute a severance event under the applicable plans, programs, agreements or arrangements.

The Transition Services Agreement sets forth the terms on which we will provide Phillips 66, and Phillips 66 will provide to us, certain services or functions Phillips 66 and ConocoPhillips historically have shared. Transition services include administrative, payroll, human resources, data processing, environmental health and safety, financial audit support, financial transaction support, and other support services, information technology systems and various other corporate services. The agreement provides for the provision of specified transition services, generally for a period of up to 12 months, with a possible extension of 6 months (an aggregate of 18 months), on a cost or a cost-plus basis.

The following table presents the carrying value of the major categories of assets and liabilities of Phillips 66, reflected on our consolidated balance sheet at December 31, 2011:

	Millions of Dollars
Assets	
Accounts and notes receivable	$ 8,353
Accounts and notes receivable related parties	1,671
Inventories	3,403
Prepaid expenses and other current assets	443
Total current assets of discontinued operations	13,870
Investments and long-term receivables	10,304
Loans and advances related parties	1
Net properties, plants and equipment	15,047
Goodwill	3,332
Intangibles	732
Other assets	121
Total assets of discontinued operations	$ 43,407
Liabilities	
Accounts payable	$ 10,007
Accounts payable related parties	785
Short-term debt	30
Accrued income and other taxes	967
Employee benefit obligations	76
Other accruals	411
Total current liabilities of discontinued operations	12,276
Long-term debt	361
Asset retirement obligations and accrued environmental costs	787
Deferred income taxes	5,533
Employee benefit obligations	1,057
Other liabilities and deferred credits	417
Total liabilities of discontinued operations	$ 20,431

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Sales and other operating revenues and income from discontinued operations related to Phillips 66 were as follows:

		Millions of Dollars		
		2012	2011	2010
Sales and other operating revenues from discontinued operations	$	**62,109**	196,068	146,542
Income from discontinued operations before-tax	$	**1,768**	6,776	1,438
Income tax expense		**534**	1,729	470
Income from discontinued operations	$	**1,234**	5,047	968

Income from discontinued operations after-tax includes transaction, information systems and other costs incurred to effect the separation of $70 million and $17 million for the years ended December 31, 2012 and 2011. No separation costs were incurred in 2010.

Prior to the separation, commodity sales to Phillips 66 were $4,973 million for the year ended December 31, 2012; $15,822 million for the year ended December 31, 2011; and $13,412 million for the year ended December 31, 2010. Commodity purchases from Phillips 66 prior to the separation were $166 million for the year ended December 31, 2012; $516 million for the year ended December 31, 2011; and $479 million for the year ended December 31, 2010. Prior to May 1, 2012, commodity sales and related costs were eliminated in consolidation between ConocoPhillips and Phillips 66. Beginning May 1, 2012, these revenues and costs represent third-party transactions with Phillips 66. Although we expect certain transactions related to the sale and purchase of crude oil, natural gas and products to continue in the future with Phillips 66, the expected continuing cash flows are not considered significant; thus, the operations and cash flows of our former Downstream business are considered to be eliminated from our ongoing operations.

Other Discontinued Operations

As part of our ongoing strategic asset disposition program, we agreed to sell our interest in the North Caspian Sea Production Sharing Agreement (Kashagan) and our Algerian and Nigerian businesses (collectively, the Disposition Group). The Disposition Group is part of the Other International operating segment.

On November 26, 2012, we notified government authorities in Kazakhstan and co-ventures of our intent to sell the Company s 8.4 percent interest in Kashagan to ONGC Videsh Limited. Expected proceeds are approximately $5 billion, which represents the purchase price plus expected working capital and customary adjustments at closing. The transaction is expected to close by mid-2013. We recorded a pre-tax impairment of $606 million in the fourth quarter of 2012 to reduce the carrying value to fair value, less costs to sell. As of December 31, 2012, the carrying value of the net assets related to our interest in Kashagan after the impairment adjustment was $5 billion.

On December 18, 2012, we entered into an agreement with Pertamina to sell our wholly owned subsidiary, ConocoPhillips Algeria Ltd., for a total of $1.75 billion plus customary adjustments. The transaction is anticipated to close by mid-2013. We received a deposit of $175 million in December 2012, which is included in the Other accruals line on our consolidated balance sheet and in the Other line of cash flows from investing activities on our consolidated statement of cash flows. The deposit is refundable in the event our co-venturer exercises its preemptive rights, which have been waived, or government approval is not received. As of December 31, 2012, the net carrying value of our Algerian assets was $669 million.

On December 20, 2012, we entered into agreements with affiliates of Oando PLC to sell our Nigerian business unit for a total of $1.79 billion plus customary adjustments. The transaction is anticipated to close by mid-2013, following appropriate consultations with stakeholders. We received a deposit of $435 million in December 2012, which is included in the Other accruals line on our consolidated balance sheet and in the Other line of cash flows from investing activities on our consolidated statement of cash flows. The deposit

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is only refundable in the event of default by us. As of December 31, 2012, the net carrying value of our Nigerian assets was $323 million.

At December 31, 2012, we classified $29 million of loans and advances to related parties in the Accounts and notes receivable related parties line and $6,905 million of noncurrent assets in the Prepaid expenses and other current assets line of our consolidated balance sheet. In addition, we classified $759 million of noncurrent liabilities in the Accrued income and other taxes line and $131 million of asset retirement obligations in the Other accruals line of our consolidated balance sheet. The carrying amounts of the major classes of assets and liabilities associated with the Disposition Group at December 31 were as follows:

	Millions of Dollars	
	2012	2011
Assets		
Accounts and notes receivable	**$ 268**	255
Accounts and notes receivable related parties	**1**	4
Inventories	**44**	48
Prepaid expenses and other current assets	**220**	279
Total current assets of discontinued operations	**533**	586
Investments and long-term receivables	**272**	261
Loans and advances related parties	**29**	13
Net properties, plants and equipment	**6,629**	6,657
Other assets	**4**	9
Total assets of discontinued operations	**$ 7,467**	7,526
Liabilities		
Accounts payable	**$ 471**	644
Accrued income and other taxes	**125**	185
Employee benefit obligations	**-**	1
Total current liabilities of discontinued operations	**596**	830
Asset retirement obligations and accrued environmental costs	**131**	138
Deferred income taxes	**759**	989
Total liabilities of discontinued operations	**$ 1,486**	1,957

Sales and other operating revenues and income from discontinued operations related to the Disposition Group during 2012, 2011 and 2010 were as follows:

	Millions of Dollars		
	2012	2011	2010
Sales and other operating revenues from discontinued operations	**$ 1,369**	1,560	1,081
Income (loss) from discontinued operations before-tax	**$ (6)**	829	437
Income tax expense	**211**	562	293

Income (loss) from discontinued operations	**$ (217)**	267	144

Note 3 Variable Interest Entities (VIEs)

We hold variable interests in VIEs that have not been consolidated because we are not considered the primary beneficiary. Information on our significant VIEs follows:

Freeport LNG Development, L.P. (Freeport LNG)

We have an agreement with Freeport LNG to participate in a liquefied natural gas (LNG) receiving terminal in Quintana, Texas. We have no ownership in Freeport LNG; however, we own a 50 percent interest in Freeport LNG GP, Inc. (Freeport GP), which serves as the general partner managing the venture. We entered into a credit agreement with Freeport LNG, whereby we agreed to provide loan financing for the construction of the terminal. We also entered into a long-term agreement with Freeport LNG to use 0.9 billion cubic feet per day of regasification capacity. The terminal became operational in June 2008, and we began making payments under the terminal use agreement. Freeport LNG began making loan repayments in September 2008, and the loan balance outstanding was $565 million at December 31, 2012. Freeport LNG is a VIE because Freeport GP holds no equity in Freeport LNG, and the limited partners of Freeport LNG do not have any substantive decision making ability. Since we do not have the unilateral power to direct the key activities which most significantly impact its economic performance, we are not the primary beneficiary of Freeport LNG. These key activities primarily involve or relate to operating and maintaining the terminal. We also performed an analysis of the expected losses and determined we are not the primary beneficiary. This expected loss analysis took into account that the credit support arrangement requires Freeport LNG to maintain sufficient commercial insurance to mitigate any loan losses. The loan to Freeport LNG is accounted for as a financial asset, and our investment in Freeport GP is accounted for as an equity investment.

Australia Pacific LNG (APLNG)

APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. We are not the primary beneficiary of APLNG because we share with Origin Energy and China Petrochemical Corporation (Sinopec) the power to direct the key activities of APLNG that most significantly impact its economic performance, which involve activities related to the production and commercialization of coalbed methane, as well as LNG processing and export marketing. As a result, we do not consolidate APLNG, and it is accounted for as an equity method investment.

As of December 31, 2012, we have not provided, nor do we expect to provide in the future, any financial support to APLNG other than amounts previously contractually required. In addition, unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of APLNG. See Note 6 Investments, Loans and Long-Term Receivables, and Note 13 Guarantees, for additional information.

Note 4 Inventories

Inventories at December 31 were:

		Millions of Dollars	
		2012	2011
Crude oil and petroleum products	$	**244**	3,633
Materials, supplies and other		**721**	998
	$	**965**	4,631

Inventories valued on the LIFO basis totaled $147 million and $3,387 million at December 31, 2012 and 2011, respectively. The estimated excess of current replacement cost over LIFO cost of inventories amounted to approximately $200 million and $8,400 million at December 31, 2012 and 2011, respectively. In 2012, a liquidation of LIFO inventory values increased net income from continuing operations by $32 million.

A significant portion of our inventories at December 31, 2011, was related to our Downstream business. See Note 2 Discontinued Operations, for additional information.

Note 5 Assets Held for Sale or Sold

Assets Held for Sale

Our interest in Kashagan and the Algerian and Nigerian business units were considered held for sale as of December 31, 2012. These assets are classified as discontinued operations. See Note 2 Discontinued Operations.

In January 2013, we entered into an agreement to sell the majority of our properties in the Cedar Creek Anticline (CCA) to Denbury Resources for $1.05 billion plus customary adjustments. The transaction is expected to close in the first quarter of 2013. CCA is included in our Lower 48 and Latin America segment. At December 31, 2012, the asset was considered held for sale. In December 2012, we recorded a pre-tax impairment of $192 million to reduce the carrying value to fair value. We also reclassified $1.08 billion of related noncurrent assets, primarily PP&E, to Prepaid expenses and other current assets and $426 million of noncurrent liabilities, comprised of deferred tax liabilities and asset retirement obligations (ARO), to Accrued income and other taxes and Other accruals .

Assets Sold

All gains are reported before-tax and are included in the Gain on dispositions line on the consolidated income statement.

2012

In March 2012, we sold our Vietnam business for $1,095 million, including customary working capital adjustments, and recognized a gain of $931 million. At the time of the disposition, the net carrying value of the business, which was included in the Asia Pacific and Middle East segment, was approximately $164 million, which included $352 million of PP&E, $69 million of ARO and $145 million of deferred income taxes.

In April 2012, we sold our interest in the Statfjord Field and associated satellites, all of which are located in the North Sea, for $228 million and recognized a gain of $429 million. At the time of disposition, the carrying value of our interest, which was included in the Europe segment, was negative $201 million, which included $205 million of PP&E and $445 million of ARO.

In May 2012, we sold our interest in the North Sea Alba Field for $220 million, and recognized a gain of $155 million. At the time of disposition, the carrying value of our interest, which was included in the Europe segment, was $65 million, which included $160 million of PP&E and $86 million of ARO.

In August 2012, we sold our 30 percent interest in Naryanmarneftegaz (NMNG) and certain related assets for $450 million, and recognized a gain of $206 million. At the time of the disposition, the carrying value of our equity investment in NMNG, which was included in the Other International segment, was $244 million.

2011

In the first quarter of 2011, we sold the remainder of our interest in LUKOIL for cash proceeds of $1,243 million, and recognized a gain of $360 million.

2010

During 2010, we sold a portion of our interest in LUKOIL, consisting of 151 million shares, for $8,345 million, and recognized a gain of $1,749 million. The cost basis for the shares, which were classified as available-for-sale, was average cost.

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In June 2010, we sold our 9.03 percent interest in the Syncrude Canada Ltd. joint venture for $4.6 billion, and recognized a gain of $2.9 billion. At the time of disposition, Syncrude had a net carrying value of $1.75 billion, which included $1.97 billion of PP&E.

Note 6 Investments, Loans and Long-Term Receivables

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

		Millions of Dollars	
		2012	2011
Equity investments	$	**22,431**	30,985
Loans and advances related parties		**1,517**	1,675
Long-term receivables		**609**	559
Other investments		**449**	564
	$	**25,006**	33,783

Equity Investments

Affiliated companies in which we had a significant equity investment at December 31, 2012, included:

- Australia Pacific LNG Pty Ltd (APLNG) 37.5 percent owned joint venture with Origin Energy (37.5 percent) and China Petrochemical Corporation (Sinopec) (25 percent) to develop coalbed methane production from the Bowen and Surat basins in Queensland, Australia, as well as process and export LNG.
- FCCL Partnership 50 percent owned business venture with Cenovus Energy Inc. produces bitumen in the Athabasca oil sands in northeastern Alberta and sells the bitumen blend.
- Qatar Liquefied Gas Company Limited 3 (QG3) 30 percent owned joint venture with affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent) produces and liquefies natural gas from Qatar s North Field.

Prior to the separation of the Downstream business, we also had significant equity investments in the following affiliated companies:

- WRB Refining LP 50 percent owned business venture with Cenovus owns the Wood River and Borger refineries, which process crude oil into refined products.
- DCP Midstream, LLC 50 percent owned joint venture with Spectra Energy owns and operates gas plants, gathering systems, storage facilities and fractionation plants.
- Chevron Phillips Chemical Company LLC 50 percent owned joint venture with Chevron Corporation manufactures and markets petrochemicals and plastics.

We no longer hold significant equity investments in these affiliated companies as a result of the separation of the Downstream business. See Note 2 Discontinued Operations, for additional information.

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Summarized 100 percent earnings information for equity method investments in affiliated companies, combined, was as follows (information includes LUKOIL until loss of significant influence as well as equity investments disposed of in connection with the separation of the Downstream business until the date of the separation):

	Millions of Dollars		
	2012	2011	2010
Revenues	$ **17,903**	77,263	105,589
Income before income taxes	**5,986**	11,958	11,250
Net income	**5,767**	11,089	9,495

Summarized 100 percent balance sheet information for equity method investments in affiliated companies, combined, was as follows (information includes equity investments disposed of in connection with the separation of the Downstream business until the date of the separation):

	Millions of Dollars	
	2012	2011
Current assets	$ **11,510**	21,530
Noncurrent assets	**46,743**	76,300
Current liabilities	**3,721**	9,708
Noncurrent liabilities	**9,698**	22,993

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, 2012, retained earnings included $803 million related to the undistributed earnings of affiliated companies. Dividends received from affiliates were $1,351 million, $3,670 million and $2,282 million in 2012, 2011 and 2010, respectively.

APLNG

In 2008, we closed on a transaction with Origin Energy, an integrated Australian energy company, to further enhance our long-term Australasian natural gas business. APLNG is focused on coalbed methane production from the Bowen and Surat basins in Queensland, Australia, and LNG processing and export sales. This transaction gives us access to coalbed methane resources in Australia and enhances our LNG position with the expected creation of an additional LNG hub targeting the Asia Pacific markets. Origin is the operator of APLNG s production and pipeline system, while we will operate the LNG facility.

In April 2011, APLNG and Sinopec signed definitive agreements for APLNG to supply up to 4.3 million tonnes of LNG per year for 20 years. The agreements also specified terms under which Sinopec subscribed for a 15 percent equity interest in APLNG, with both our ownership interest and Origin Energy s ownership interest diluting to 42.5 percent. The Subscription Agreement was completed in August 2011, and we recorded a loss on disposition of $279 million before- and after-tax from the dilution. The book value of our investment in APLNG was reduced by $795 million, and we reduced the currency translation adjustment associated with our investment by $516 million.

In January 2012, APLNG and Sinopec signed an amendment to their existing LNG sales agreement for the sale and purchase of an additional 3.3 million tonnes of LNG per year through 2035. This agreement, in combination with the execution of an LNG sale and purchase agreement with The Kansai Electric Power Co. Inc., in June 2012 for approximately 1.0 million tonnes of LNG per year through 2035, finalized the marketing of the second train.

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In July 2012, the APLNG co-venturers sanctioned the development of a second 4.5-million-tonnes-per-year LNG production train. Upon sanctioning of the second train in July and in conjunction with the LNG sales agreement, Sinopec subscribed to additional shares in APLNG, which increased its equity interest from 15 percent to 25 percent. As a result, on July 12, 2012, both our ownership interest and Origin s ownership interest diluted from 42.5 percent to 37.5 percent. We recorded a before- and after-tax loss of $133 million from the dilution in the third quarter of 2012. The book value of our investment in APLNG was reduced by $453 million, and we reduced the foreign currency translation adjustment associated with our investment by $320 million.

In addition, APLNG executed project financing agreements for an $8.5 billion project finance facility during the third quarter of 2012. The $8.5 billion project finance facility is composed of financing agreements executed by APLNG with the Export-Import Bank of the United States for approximately $2.9 billion, the Export-Import Bank of China for approximately $2.7 billion, and a syndicate of Australian and international commercial banks for approximately $2.9 billion. In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility which will be released upon meeting certain completion milestones. See Note 13 Guarantees, for additional information.

APLNG is considered a VIE, as it has entered into certain contractual arrangements that provide it with additional forms of subordinated financial support. See Note 3 Variable Interest Entities (VIEs) for additional information.

At December 31, 2012, the book value of our equity method investment in APLNG was $10,394 million, which includes $2,568 million of cumulative translation effects due to a strengthening Australian dollar relative to the U.S. dollar. The historical cost basis of our 37.5 percent share of net assets on the books of APLNG under U.S. generally accepted accounting principles was $3,961 million, resulting in a basis difference of $6,433 million on our books. The amortizable portion of the basis difference, $4,686 million associated with PP&E, has been allocated on a relative fair value basis to individual exploration and production license areas owned by APLNG, most of which are not currently in production. Any future additional payments are expected to be allocated in a similar manner. Each exploration license area will periodically be reviewed for any indicators of potential impairment, which, if required, would result in acceleration of basis difference amortization. As the joint venture begins producing natural gas from each license, we amortize the basis difference allocated to that license using the unit-of-production method. Included in net income attributable to ConocoPhillips for 2012, 2011 and 2010 was after-tax expense of $19 million, $17 million and $5 million, respectively, representing the amortization of this basis difference on currently producing licenses.

FCCL

FCCL Partnership, a Canadian upstream 50/50 general partnership with Cenovus Energy Inc., produces bitumen in the Athabasca oil sands in northeastern Alberta and sells the bitumen blend. We account for our investment in FCCL under the equity method of accounting, with the operating results of our investment in FCCL converted to reflect the use of the successful efforts method of accounting for oil and gas exploration and development activities.

At December 31, 2012, the book value of our investment in FCCL was $9,972 million. FCCL s operating assets consist of the Foster Creek and Christina Lake steam-assisted gravity drainage bitumen projects, both located in the eastern flank of the Athabasca oil sands in northeastern Alberta. Cenovus is the operator and managing partner of FCCL. We are obligated to contribute $7.5 billion, plus accrued interest, to FCCL over a 10-year period that began in 2007. For additional information on this obligation, see Note 12 Joint Venture Acquisition Obligation.

QG3

QG3 is a joint venture that owns an integrated large-scale LNG project located in Qatar. We provided project financing, with a current outstanding balance of $1,092 million as described below under Loans and Long-term Receivables. At December 31, 2012, the book value of our equity method investment in QG3 excluding the project financing was $984 million. We have terminal and pipeline use agreements with Golden Pass LNG

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Terminal and affiliated Golden Pass Pipeline near Sabine Pass, Texas, in which we have a 12.4 percent interest, intended to provide us with terminal and pipeline capacity for the receipt, storage and regasification of LNG purchased from QG3. However, currently the LNG from QG3 is being sold to markets outside of the United States.

Loans and Long-term Receivables

As part of our normal ongoing business operations and consistent with industry practice, we enter into numerous agreements with other parties to pursue business opportunities. Included in such activity are loans and long-term receivables to certain affiliated and non-affiliated companies. Loans are recorded when cash is transferred or seller financing is provided to the affiliated or non-affiliated company pursuant to a loan agreement. The loan balance will increase as interest is earned on the outstanding loan balance and will decrease as interest and principal payments are received. Interest is earned at the loan agreement s stated interest rate. Loans and long-term receivables are assessed for impairment when events indicate the loan balance may not be fully recovered.

At December 31, 2012, significant loans to affiliated companies include the following:

- $565 million in loan financing to Freeport LNG Development, L.P. for the construction of an LNG receiving terminal that became operational in June 2008. Freeport began making repayments in 2008 and is required to continue making repayments through full repayment of the loan in 2026. Repayment by Freeport is supported by process-or-pay capacity service payments made by us to Freeport under our terminal use agreement.

- $1,092 million in project financing to QG3. We own a 30 percent interest in QG3, for which we use the equity method of accounting. The other participants in the project are affiliates of Qatar Petroleum and Mitsui. QG3 secured project financing of $4.0 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. On December 15, 2011, QG3 achieved financial completion and all project loan facilities became nonrecourse to the project participants. Semi-annual repayments began in January 2011 and will extend through July 2022.

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

Note 7 Suspended Wells

The following table reflects the net changes in suspended exploratory well costs during 2012, 2011, and 2010:

	Millions of Dollars		
	2012	2011	2010
Beginning balance at January 1	$ **1,037**	1,013	908
Additions pending the determination of proved reserves	**185**	96	216
Reclassifications to proved properties	**(144)**	(72)	(106)
Sales of suspended well investment	**(18)**	-	(4)
Charged to dry hole expense	**(22)**	-	(1)
Ending balance at December 31	$ **1,038** *	1,037	1,013

**Includes $190 million of assets held for sale $133 million in Kazakhstan and $57 million in Nigeria.*

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The following table provides an aging of suspended well balances at December 31, 2012, 2011 and 2010:

	Millions of Dollars		
	2012	2011	2010
Exploratory well costs capitalized for a period of one year or less	**$ 186**	115	220
Exploratory well costs capitalized for a period greater than one year	**852**	922	793
Ending balance	**$ 1,038 ***	1,037	1,013
Number of projects with exploratory well costs capitalized for a period greater than one year	**35**	40	40

**Includes $190 million of assets held for sale $133 million in Kazakhstan and $57 million in Nigeria.*

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, 2012:

	Millions of Dollars			
		Suspended Since		
	Total	2009-2011	2006-2008	2001-2005
Aktote Kazakhstan(2)(3)	$ 19	-	-	19
Alpine Satellite Alaska(2)	23	-	-	23
Browse Basin Australia(1)	216	216	-	-
Caldita/Barossa Australia(1)	78	-	44	34
Clair SW UK(1)	14	14	-	-
Fiord West Alaska(2)	16	-	16	-
Kairan Kazakhstan(2)(3)	27	-	14	13
Kalamkas Kazakhstan(2)(3)	14	5	5	4
Kashagan II Kazakhstan(2)(3)	45	9	26	10
Muskwa Canada(1)	56	56	-	-
NPR-A Alaska(2)	17	17	-	-
Pisagan Malaysia(2)	10	-	-	10
Saleski Canada(1)	18	-	18	-
Shenandoah Lower 48(1)	43	43	-	-
Sunrise 3 Australia(2)	13	-	13	-
Surmont 3 and beyond Canada(1)	45	21	22	2
Thornbury Canada(1)	21	-	21	-
Tiber Lower 48(1)	40	40	-	-
Titan Norway(2)	12	12	-	-
Ubah Malaysia(2)	36	11	25	-
Uge Nigeria(2)(3)	30	-	16	14
Other of $10 million or less each(1)(2)	59	17	40	2
Total	$ 852	461	260	131

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

(3) Assets held for sale as of December 31, 2012.

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Note 8 Goodwill and Intangibles

Goodwill

Changes in the carrying amount of goodwill, all associated with the Downstream business, were as follows:

		Millions of Dollars	
		2012	2011
Goodwill balance as of January 1	$	**3,332**	3,633
Goodwill allocated to assets held for sale or sold		**-**	(273)
Tax and other adjustments		**(2)**	(28)
Separation of Downstream business		**(3,330)**	-
Goodwill balance as of December 31	$	**-**	3,332

Intangible Assets

At year-end 2012, our intangible asset balance was $4 million, compared with $745 million at year-end 2011. Intangible assets of $730 million related to our Downstream business and were transferred to Phillips 66 upon the separation.

Note 9 Impairments

During 2012, 2011 and 2010, we recognized the following before-tax impairment charges:

		Millions of Dollars		
		2012	2011	2010
Alaska	$	**3**	2	6
Lower 48 and Latin America		**192**	71	19
Canada		**262**	253	13
Europe		**211**	(37)	43
Asia Pacific and Middle East		**4**	-	-
Corporate		**8**	32	-
	$	**680**	321	81

_2012_

In 2012, we recorded a $192 million property impairment in the Lower 48 and Latin America segment related to the planned disposition of Cedar Creek Anticline, located in southwestern North Dakota and eastern Montana.

The Canada segment included a $213 million property impairment for the carrying value of capitalized project development costs associated with our Mackenzie Gas Project. Advancement of the project was suspended indefinitely in the first quarter of 2012 due to a continued decline in market conditions and the lack of acceptable commercial terms. We also recorded a $481 million impairment for the undeveloped leasehold costs associated with the project, which was included in the Exploration expenses line on our consolidated income statement. Additionally, we recorded impairments on various producing and non-producing properties.

In Europe, we recorded impairments of $211 million, mainly related to ARO revisions for properties which have ceased production or are nearing the end of their useful lives.

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2011

During 2011, we recorded property impairments of $289 million, primarily in our Lower 48 and Latin America and Canada segments, largely as a result of lower natural gas price assumptions and reduced volume forecasts.

2010

During 2010, we recorded various property impairments of $81 million, primarily in our Europe and Lower 48 and Latin America segments.

Note 10 Asset Retirement Obligations and Accrued Environmental Costs

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

	Millions of Dollars	
	2012	2011
Asset retirement obligations	$ **9,164**	8,920
Accrued environmental costs	**364**	922
Total asset retirement obligations and accrued environmental costs	**9,528**	9,842
Asset retirement obligations and accrued environmental costs due within one year*	**(581)**	(513)
Long-term asset retirement obligations and accrued environmental costs	$ **8,947**	9,329

* *Classified as a current liability on the balance sheet under Other accruals and includes $158 million of liabilities associated with assets held for sale at December 31, 2012.*

Asset Retirement Obligations

We record the fair value of a liability for an asset retirement obligation when it is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize the associated asset retirement cost by increasing the carrying amount of the related PP&E. If, in subsequent periods, our estimate of this liability changes, we will record an adjustment to both the liability and PP&E. Over time, the liability increases for the change in its present value, while the capitalized cost depreciates over the useful life of the related asset.

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

During 2012 and 2011, our overall asset retirement obligation changed as follows:

	Millions of Dollars	
	2012	2011
Balance at January 1	$ **8,920**	8,776
Accretion of discount	**412**	435
New obligations	**315**	153
Changes in estimates of existing obligations	**543**	29

Spending on existing obligations	**(319)**	(327)
Property dispositions	**(607)**	(60)
Foreign currency translation	**281**	(86)
Separation of Downstream business	**(381)**	-
Balance at December 31	**$ 9,164**	8,920

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Accrued Environmental Costs

Total accrued environmental costs at December 31, 2012 and 2011, were $364 million and $922 million, respectively. A significant portion of our environmental contingencies at December 31, 2011, related to our Downstream business. See Note 2 Discontinued Operations, for additional information. The remaining 2012 decrease in total accrued environmental costs is due to payments and settlements during the year exceeding new accruals, accrual adjustments and accretion.

We had accrued environmental costs of $279 million and $571 million at December 31, 2012 and 2011, respectively, related to remediation activities required by Canada and various states within the U.S. at operated sites. We had also accrued in Corporate and Other $70 million and $274 million of environmental costs associated with nonoperator sites at December 31, 2012 and 2011, respectively. In addition, $15 million and $77 million were included at both December 31, 2012 and 2011, respectively, where the company has been named a potentially responsible party under the Federal Comprehensive Environmental Response, Compensation and Liability Act, or similar state laws. Accrued environmental liabilities are expected to be paid over periods extending up to 30 years.

Because a large portion of the accrued environmental costs were acquired in various business combinations, they are discounted obligations. Expected expenditures for acquired environmental obligations are discounted using a weighted-average 5 percent discount factor, resulting in an accrued balance for acquired environmental liabilities of $142 million at December 31, 2012. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $20 million in 2013, $16 million in 2014, $14 million in 2015, $8 million in 2016, $7 million in 2017, and $98 million for all future years after 2017.

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Note 11 Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2012	2011
9.125% Debentures due 2021	**$ 150**	150
8.20% Debentures due 2025	**150**	150
8.125% Notes due 2030	**600**	600
7.9% Debentures due 2047	**100**	100
7.8% Debentures due 2027	**300**	300
7.68% Notes due 2012	**-**	7
7.65% Debentures due 2023	**88**	88
7.625% Debentures due 2013	**100**	100
7.40% Notes due 2031	**500**	500
7.375% Debentures due 2029	**92**	92
7.25% Notes due 2031	**500**	500
7.20% Notes due 2031	**575**	575
7% Debentures due 2029	**200**	200
6.95% Notes due 2029	**1,549**	1,549
6.875% Debentures due 2026	**67**	67
6.65% Debentures due 2018	**297**	297
6.50% Notes due 2039	**2,250**	2,250
6.50% Notes due 2039	**500**	500
6.00% Notes due 2020	**1,000**	1,000
5.951% Notes due 2037	**645**	645
5.95% Notes due 2036	**500**	500
5.90% Notes due 2032	**505**	505
5.90% Notes due 2038	**600**	600
5.75% Notes due 2019	**2,250**	2,250
5.625% Notes due 2016	**1,250**	1,250
5.50% Notes due 2013	**750**	750
5.20% Notes due 2018	**500**	500
4.75% Notes due 2012	**-**	897
4.75% Notes due 2014	**400**	1,500
4.60% Notes due 2015	**1,500**	1,500
4.40% Notes due 2013	**-**	400
2.4% Notes due 2022	**1,000**	-
1.05% Notes due 2017	**1,000**	-
Commercial paper at 0.15% 0.252% at year-end 2012 and 0.34% 0.341% at year-end 2011	**1,055**	1,128
Industrial Development Bonds due 2012 through 2038 at 0.04% 0.11% at year-end 2012 and 0.08% 5.75% at year-end 2011	**18**	252
Guarantee of savings plan bank loan payable due 2015 at 2.29% at year-end 2011	**-**	15
Note payable to Merey Sweeny, L.P. due 2020 at 7% (related party)	**-**	133
Marine Terminal Revenue Refunding Bonds due 2031 at 0.08% 0.2% at year-end 2012 and 0.08% 0.15% at year-end 2011	**265**	265
Other	**24**	28
Debt at face value	**21,280**	22,143
Capitalized leases	**16**	31
Net unamortized premiums and discounts	**429**	449

Total debt	**21,725**	22,623
Short-term debt	**(955)**	(1,013)
Long-term debt	**$ 20,770**	21,610

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Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2013 through 2017 are: $955 million, $414 million, $1,538 million, $2,254 million and $1,020 million, respectively. At December 31, 2012, we classified $964 million of short-term debt as long-term debt, based on our ability and intent to refinance the obligation on a long-term basis under our revolving credit facilities.

During 2012, the following new debt instruments were issued:

- The $1,000 million 1.05% Notes due 2017.
- The $1,000 million 2.40% Notes due 2022.

During 2012, the following debt instruments were repaid:

- The $400 million 4.40% Notes due 2013, repaid before maturity.
- $1,100 million of the $1,500 million 4.75% Notes due 2014, repaid before maturity.
- The $897 million of 4.75% Notes due 2012, repaid at maturity.

We incurred a before-tax loss on redemption of $79 million related to the two debt instruments we repaid before maturity, consisting of a make-whole premium and unamortized issuance costs.

In May 2012, we decreased our total revolving credit facilities from $8.0 billion to $7.5 billion by terminating all commitments under the $500 million credit facility which was due to expire in July 2012. Our revolving credit facility may be used as direct bank borrowings, as support for issuances of letters of credit totaling up to $750 million, or as support for our commercial paper programs. The revolving credit 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 facility 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.

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

We have two commercial paper programs: the ConocoPhillips $6.35 billion program, primarily a funding source for short-term working capital needs, and the ConocoPhillips Qatar Funding Ltd. $1.15 billion commercial paper program, which is used to fund commitments relating to the QG3 Project. Commercial paper maturities are generally limited to 90 days. At both December 31, 2012 and 2011, we had no direct outstanding borrowings under the revolving credit facilities, with no letters of credit as of December 31, 2012, and $40 million as of December 31, 2011. In addition, under the ConocoPhillips Qatar Funding Ltd. commercial paper program, there was $1,055 million of commercial paper outstanding at December 31, 2012, compared with $1,128 million at December 31, 2011. Since we had $1,055 million of commercial paper outstanding and had issued no letters of credit, we had access to $6.4 billion in borrowing capacity under our revolving credit facilities at December 31, 2012.

Note 12 Joint Venture Acquisition Obligation

We are obligated to contribute $7.5 billion, plus interest, over a 10-year period that began in 2007, to FCCL. 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, $772 million was short-term and was included in the Accounts payable related parties line on our December 31, 2012 consolidated balance sheet. The principal portion of these payments, which totaled $733 million in 2012, is included in the Other line in the financing activities section of our consolidated statement of cash flows. Interest accrues at a fixed annual rate of 5.3 percent on the unpaid principal balance. Fifty percent of the quarterly interest payment is reflected as a capital contribution and is included in the Capital expenditures and investments line on our consolidated statement of cash flows.

Note 13 Guarantees

At December 31, 2012, we were liable for certain contingent obligations under various contractual arrangements as described below. We recognize a liability at inception for the fair value of our obligation as a guarantor for newly issued or modified guarantees. Unless the carrying amount of the liability is noted below, we have not recognized a liability either because the guarantees were issued prior to December 31, 2002, or because the fair value of the obligation is immaterial. In addition, unless otherwise stated, we are not currently performing with any significance under the guarantee and expect future performance to be either immaterial or have only a remote chance of occurrence.

APLNG Guarantees

At December 31, 2012, we have outstanding multiple guarantees in connection with our 37.5 percent ownership interest in APLNG. The following is a description of the guarantees with values calculated utilizing December 2012 exchange rates:

We have guaranteed APLNG s performance with regard to a construction contract executed in connection with APLNG s issuance of the Train 1 and Train 2 Notices to Proceed. We estimate the remaining term of this guarantee is 4 years. Our maximum potential amount of future payments related to this guarantee is approximately $180 million and would become payable if APLNG cancels the applicable construction contract and does not perform with respect to the amounts owed to the contractor.

We have issued a construction completion guarantee related to the third-party project financing secured by APLNG. Our maximum potential amount of future payments under the guarantee is estimated to be $3.2 billion, which could be payable if the full debt financing capacity is utilized and completion of the project is not achieved. Our guarantee of the project financing will be released upon meeting certain completion milestones, which we estimate would occur beginning in 2016. Our maximum exposure at December 31, 2012, is $860 million based upon our pro-rata share of the facility used at that date. At December 31, 2012, the carrying value of this guarantee is approximately $114 million.

In conjunction with our original purchase of an ownership interest in APLNG from Origin Energy in October 2008, we agreed to guarantee an existing obligation of APLNG to deliver natural gas under several sales agreements with remaining terms of 4 to 19 years. Our maximum potential amount of future payments, or cost of volume delivery, under these guarantees is estimated to be $1.0 billion ($2.4 billion in the event of intentional or reckless breach) and would become payable if APLNG fails to meet its obligations under these agreements and the obligations cannot otherwise be mitigated. Future payments are considered unlikely, as the payments, or cost of volume delivery, would only be triggered if APLNG does not have enough natural gas to meet these sales commitments and if the co-venturers do not make necessary equity contributions into APLNG.

We have guaranteed the performance of APLNG with regard to certain other contracts executed in connection with the project s continued development. The guarantees have remaining terms of up to 33 years or the life of the venture. Our maximum potential amount of future payments related to these guarantees is approximately $150 million and would become payable if APLNG does not perform.

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Guarantees of Joint Venture Debt

At December 31, 2012, we had guarantees outstanding for our portion of joint venture debt obligations, which have remaining terms of up to 23 years. The maximum potential amount of future payments under the guarantees is approximately $60 million. Payment would be required if a joint venture defaults on its debt obligations.

Other Guarantees

We have other guarantees with maximum future potential payment amounts totaling approximately $270 million, which consist primarily of guarantees of the residual value of leased corporate aircraft, guarantees to fund the short-term cash liquidity deficit of two joint ventures and a guarantee of minimum charter revenue for an LNG vessel. These guarantees have remaining terms of up to 11 years or life of the venture.

Indemnifications

Over the years, we have entered into various agreements to sell ownership interests in certain corporations, joint ventures and assets that gave rise to qualifying indemnifications. Agreements associated with these sales include indemnifications for taxes, environmental liabilities, permits and licenses, employee claims, real estate indemnity against tenant defaults, and litigation. The terms of these indemnifications vary greatly. The majority of these indemnifications are related to environmental issues, the term is generally indefinite and the maximum amount of future payments is generally unlimited. The carrying amount recorded for these indemnifications at December 31, 2012, was approximately $70 million. We amortize the indemnification liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of indemnity. In cases where the indemnification term is indefinite, we will reverse the liability when we have information the liability is essentially relieved or amortize the liability over an appropriate time period as the fair value of our indemnification exposure declines. Although it is reasonably possible future payments may exceed amounts recorded, due to the nature of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. Included in the recorded carrying amount were approximately $50 million of environmental accruals for known contamination that are included in the Asset retirement obligations and accrued environmental costs line on our consolidated balance sheet. For additional information about environmental liabilities, see Note 14 Contingencies and Commitments.

In connection with the separation of the Downstream business, the Company entered into an Indemnification and Release Agreement with Phillips 66. See Note 2 Discontinued Operations, for additional information. This agreement provides for cross-indemnities between Phillips 66 and ConocoPhillips and established procedures for handling claims subject to indemnification and related matters. We evaluated the impact of the indemnifications given and the Phillips 66 indemnifications received as of the separation date and concluded those fair values were immaterial.

Note 14 Contingencies and Commitments

A number of lawsuits involving a variety of claims have been made against ConocoPhillips that arise in the ordinary course of business. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the case of income tax-related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain. See Note 20 Income Taxes, for additional information about income tax-related contingencies.

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

Environmental

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

Although liability of those potentially responsible for environmental remediation costs is generally joint and several for federal sites and frequently so for state sites, we are usually only one of many companies cited at a particular site. Due to the joint and several liabilities, we could be responsible for all cleanup costs related to any site at which we have been designated as a potentially responsible party. We have been successful to date in sharing cleanup costs with other financially sound companies. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess the site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or may attain a settlement of liability. Where it appears that other potentially responsible parties may be financially unable to bear their proportional share, we consider this inability in estimating our potential liability, and we adjust our accruals accordingly. As a result of various acquisitions in the past, we assumed certain environmental obligations. Some of these environmental obligations are mitigated by indemnifications made by others for our benefit, and some of the indemnifications are subject to dollar limits and time limits.

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and comparable state sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except those acquired in a purchase business combination, which we record on a discounted basis) for planned investigation and remediation activities for sites where it is probable future costs will be incurred and these costs can be reasonably estimated. We have not reduced these accruals for possible insurance recoveries. In the future, we may be involved in additional environmental assessments, cleanups and proceedings. See Note 10 Asset Retirement Obligations and Accrued Environmental Costs, for a summary of our accrued environmental liabilities.

Legal Proceedings

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required.

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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, 2012, we had performance obligations secured by letters of credit of $852 million (issued as direct bank letters of credit) related to various purchase commitments for materials, supplies, commercial activities and services incident to the ordinary conduct of business.

In 2007, we announced we had been unable to reach agreement with respect to our migration to an *empresa mixta* structure mandated by the Venezuelan government s Nationalization Decree. As a result, Venezuela s national oil company, Petróleos de Venezuela S.A. (PDVSA), or its affiliates, directly assumed control over ConocoPhillips interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project. In response to this expropriation, we filed a request for international arbitration on November 2, 2007, with the World Bank s International Centre for Settlement of Investment Disputes (ICSID). An arbitration hearing was held before an ICSID tribunal during the summer of 2010, and we anticipate an interim decision on key legal and factual issues in 2013. In a separate commercial arbitration from the Company s ICSID claim discussed above, an International Chamber of Commerce (ICC) tribunal issued a decision in favor of the Company in September 2012, finding PDVSA owed $67 million for pre-expropriation breaches of the Petrozuata project agreements. In November 2012, based on the ICC tribunal ruling, PDVSA paid ConocoPhillips $68 million, including post-judgment interest, which resulted in a $61 million after-tax earnings increase. The Company also recognized additional income of $173 million after-tax, associated with the reversal of a related contingent liability accrual, which is recorded in the Other income line on our consolidated income statement.

In 2008, Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, initiated arbitration before ICSID against The Republic of Ecuador, as a result of the newly enacted Windfall Profits Tax Law and government-mandated renegotiation of our production sharing contracts. Despite a restraining order issued by ICSID, Ecuador confiscated the crude oil production of Burlington and its co-venturer and sold the illegally seized crude oil. In 2009, Ecuador took over operations in Blocks 7 and 21, fully expropriating our assets. In June 2010, the ICSID tribunal concluded it has jurisdiction to hear the expropriation claim. On April 24, 2012, Ecuador filed a supplemental counterclaim asserting environmental damages, which we believe are not material. The ICSID tribunal issued a decision on liability on December 14, 2012, in favor of Burlington, finding that Ecuador s seizure of Blocks 7 and 21 was an unlawful expropriation in violation of the Ecuador-U.S. Bilateral Investment Treaty. An additional arbitration phase will take place to determine the damages owed to ConocoPhillips for Ecuador s actions.

ConocoPhillips served a Notice of Arbitration on the Timor-Leste Minister of Finance in October 2012 for outstanding disputes related to a series of tax assessments. Between 2010 and 2012, ConocoPhillips has paid, under protest, tax assessments totaling approximately $227 million, which are primarily recorded in the Investments and long-term receivables line on our December 31, 2012, consolidated balance sheet. The arbitration will be conducted in Singapore under the United Nations Commission on International Trade Laws (UNCITRAL) arbitration rules, pursuant to the terms of the Tax Stability Agreement with the Timor-Leste Government. The arbitration process is currently underway. Future impacts on our business are not known at this time.

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

We have certain throughput agreements and take-or-pay agreements in support of financing arrangements. The agreements typically provide for natural gas or crude oil transportation to be used in the ordinary course of the Company s business. The aggregate amounts of estimated payments under these various agreements are: 2013 $137 million; 2014 $136 million; 2015 $127 million; 2016 $28 million; 2017 $28 million; and 2018 and after $158 million. Total payments under the agreements were $130 million in 2012, $429 million in 2011 and $216 million in 2010.

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Note 15 Derivative and Financial Instruments

We use futures, forwards, swaps and options in various markets to meet our customer needs and capture market opportunities. Our commodity business primarily consists of natural gas, crude oil, bitumen, LNG and natural gas liquids. Under our current business model, we are not required to register as a Swap Dealer or Major Swap Participant.

Our derivative instruments are held at fair value on our consolidated balance sheet. Where these balances have the right of setoff, they are presented net. Related cash flows are recorded as operating activities on the consolidated statement of cash flows. On the consolidated income statement, realized and unrealized gains and losses are recognized either on a gross basis if directly related to our physical business or a net basis if held for trading. Gains and losses related to contracts that meet and are designated with the normal purchase normal sale exception are recognized upon settlement. We generally apply this exception to eligible crude contracts. We do not use hedge accounting for our commodity derivatives.

The following table presents the gross fair values of our commodity derivatives, excluding collateral, and the line items where they appear on our consolidated balance sheet:

	Millions of Dollars	
	2012	2011
Assets		
Prepaid expenses and other current assets	**$ 1,538**	4,433
Other assets	**105**	415
Liabilities		
Other accruals	**1,509**	4,350
Other liabilities and deferred credits	**99**	374

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

	Millions of Dollars		
	2012	2011	2010
Sales and other operating revenues	**$ (291)**	907	(964)
Other income	**(1)**	(9)	(5)
Purchased commodities	**214**	(729)	915

The table below summarizes our material net exposures resulting from outstanding commodity derivative contracts.

	Open Position Long/(Short)	
	2012	2011
Commodity		
Crude oil, refined products and natural gas liquids (millions of barrels)	**-**	(13)

Natural gas and power (billions of cubic feet equivalent)		
Fixed price	**(48)**	(57)
Basis	**125**	(25)

Foreign Currency Exchange Derivatives

We have foreign currency exchange rate risk resulting from international operations. Our foreign currency exchange derivative activity primarily consists of transactions designed to mitigate our cash-related and

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foreign currency exchange rate exposures, such as firm commitments for capital programs or local currency tax payments, dividends, and cash returns from net investments in foreign affiliates. We do not elect hedge accounting on our foreign currency exchange derivatives.

The following table presents the gross fair values of our foreign currency exchange derivatives, excluding collateral, and the line items where they appear on our consolidated balance sheet:

	Millions of Dollars	
	2012	2011
Assets		
Prepaid expenses and other current assets	**$ 32**	12
Other assets	**-**	1
Liabilities		
Other accruals	**2**	23
Other liabilities and deferred credits	**1**	-

The (gains) losses from foreign currency exchange derivatives incurred, and the line items where they appear on our consolidated income statement were:

	Millions of Dollars		
	2012	2011	2010
Foreign currency transaction (gains) losses	**$ (138)**	(9)	115

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

		In Millions Notional Currency	
		2012	2011
Foreign Currency Exchange Derivatives			
Sell U.S. dollar, buy other currencies*	USD	**2,573**	1,949
Sell euro, buy other currencies**	EUR	**-**	61
Buy U.S. dollar, sell other currencies***	USD	**140**	-
Buy euro, sell British pound	EUR	**96**	-

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

Financial Instruments

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

- Time deposits: Interest bearing deposits placed with approved financial institutions.
- Commercial paper: Unsecured promissory notes issued by a corporation, commercial bank, or government agency purchased at a discount, maturing at par.

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

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	Millions of Dollars			
	Carrying Amount			
	Cash and Cash Equivalents		Short-Term Investments	
	2012	2011	**2012**	2011
Cash	**$ 829**	1,169	**-**	-
Time Deposits				
Remaining maturities from 1 to 90 days	**2,789**	4,318	**-**	349
Commercial Paper				
Remaining maturities from 1 to 90 days	**-**	293	**-**	232
	$ 3,618	5,780	**-**	581

In conjunction with the separation of our Downstream business, we received a special cash distribution from Phillips 66 of $7,818 million. See Note 2 Discontinued Operations, for additional information. At December 31, 2012, the unused amount of the special cash distribution was $748 million and is designated as Restricted cash on our consolidated balance sheet. At December 31, 2012, the funds in the restricted cash account were invested in money market funds with maturities within 90 days from December 31, 2012.

Credit Risk

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

The credit risk from our OTC derivative contracts, such as forwards and swaps, derives from the counterparty to the transaction. Individual counterparty exposure is managed within predetermined credit limits and includes the use of cash-call margins when appropriate, thereby reducing the risk of significant nonperformance. We also use futures, swaps and option contracts that have a negligible credit risk because these trades are cleared with an exchange clearinghouse and subject to mandatory margin requirements until settled; however, we are exposed to the credit risk of those exchange brokers for receivables arising from daily margin cash calls, as well as for cash deposited to meet initial margin requirements.

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

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

The aggregate fair value of all derivative instruments with such credit risk-related contingent features that were in a liability position on December 31, 2012, was $130 million, for which no collateral was posted. If our credit rating were lowered one level from its A rating (per Standard and Poor s) on December 31, 2012, we

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would be required to post no additional collateral to our counterparties. If we were downgraded below investment grade, we would be required to post $130 million of additional collateral, either with cash or letters of credit.

Note 16 Fair Value Measurement

We carry a portion of our assets and liabilities at fair value that are measured at a reporting date using an exit price (i.e., the price that would be received to sell an asset or paid to transfer a liability) and disclosed according to the quality of valuation inputs under the following hierarchy:

Level 1: Quoted prices (unadjusted) in an active market for identical assets or liabilities.
Level 2: Inputs other than quoted prices that are directly or indirectly observable.
Level 3: Unobservable inputs that are significant to the fair value of assets or liabilities.

The classification of an asset or liability is based on the lowest level of input significant to its fair value. Those that are initially classified as Level 3 are subsequently reported as Level 2 when the fair value derived from unobservable inputs is inconsequential to the overall fair value, or if corroborated market data becomes available. Assets and liabilities that are initially reported as Level 2 are subsequently reported as Level 3 if corroborated market data is no longer available. Transfers occur at the end of the reporting period. There were no material transfers in or out of Level 1.

Recurring Fair Value Measurement

Financial assets and liabilities reported at fair value on a recurring basis primarily include commodity derivatives and certain investments to support nonqualified deferred compensation plans. The deferred compensation investments are measured at fair value using unadjusted prices available from national securities exchanges; therefore, these assets are categorized as Level 1 in the fair value hierarchy. Level 1 derivative assets and liabilities primarily represent exchange-traded futures and options that are valued using unadjusted prices available from the underlying exchange. Level 2 derivative assets and liabilities primarily represent OTC swaps, options and forward purchase and sale contracts that are valued using adjusted exchange prices, prices provided by brokers or pricing service companies that are all corroborated by market data. Level 3 derivative assets and liabilities consist of OTC swaps, options and forward purchase and sale contracts that are long term in nature and where a significant portion of fair value is calculated from underlying market data that is not readily available. The derived value uses industry standard methodologies that may consider the historical relationships among various commodities, modeled market prices, time value, volatility factors and other relevant economic measures. The use of these inputs results in management s best estimate of fair value. Level 3 activity was not material.

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The following table summarizes the fair value hierarchy for gross financial assets and liabilities (i.e., unadjusted where the right of setoff exists for commodity derivatives accounted for at fair value on a recurring basis):

	Millions of Dollars								
	December 31, 2012				December 31, 2011				
	Level 1	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	Total
Assets								
Deferred compensation investments	**$ 305**	**-**	**-**	**305**	336	-	-	336
Commodity derivatives	**1,052**	**567**	**18**	**1,637**	2,807	1,947	72	4,826
Total assets	**$ 1,357**	**567**	**18**	**1,942**	3,143	1,947	72	5,162
Liabilities								
Commodity derivatives	**$ 1,031**	**567**	**4**	**1,602**	2,970	1,722	10	4,702
Total liabilities	**$ 1,031**	**567**	**4**	**1,602**	2,970	1,722	10	4,702

Non-Recurring Fair Value Measurement

The following table summarizes the fair value hierarchy by major category for assets accounted for at fair value on a non-recurring basis:

	Millions of Dollars			
		Fair Value Measurements Using		
	Fair Value*	Level 1 Inputs	Level 3 Inputs	Before-Tax Loss
Year ended December 31, 2012				
Net PP&E (held for sale)	**$ 6,116**	**6,116**	**-**	**798**
Net PP&E (held for use)	**95**	**-**	**95**	**134**
Year ended December 31, 2011				
Net PP&E (held for use) **	$ 162	-	162	265
Equity method investments ***	274	-	274	399
Cost method investments	2	2	-	8

**Represents the fair value at the time of the impairment.*
***Before-tax loss includes $1 million related to discontinued operations.*
****Before-tax loss includes $4 million related to discontinued operations.*

<u>2012</u>

Net PP&E held for sale was written down to fair value, less costs to sell. The fair value of each asset was determined by its binding negotiated selling price.

Net PP&E held for use is comprised of various producing properties impaired to their individual fair values. The fair values were determined by the use of internal discounted cash flow models using estimates of future production, prices from futures exchanges and pricing service companies, costs and a discount rate believed to be consistent with those used by principal market participants.

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2011

During 2011, net PP&E held for use with a carrying amount of $427 million was written down to a fair value of $162 million, resulting in a before-tax loss of $265 million. The fair values were determined by the use of internal discounted cash flow models using estimates of future production, prices, costs and a discount rate believed to be consistent with those used by principal market participants and cash flow multiples for similar assets and alternative use.

Also during 2011, certain equity method investments were determined to have fair values below their carrying amount, and the impairments were considered to be other than temporary. This primarily included an investment associated with our Other International segment with a book value of $651 million, which was written down to its fair value of $256 million, resulting in a charge of $395 million before-tax. This was included in the Equity in earnings of affiliates line of our consolidated income statement. The fair value was determined by the application of an internal discounted cash flow model using estimates of future production, prices, costs and a discount rate believed to be consistent with those used by principal market participants. In addition, the fair value was determined by the comparison of market data for certain similar undeveloped properties.

Reported Fair Values of Financial Instruments

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

- Cash and cash equivalents, restricted cash and short-term investments: The carrying amount reported on the balance sheet approximates fair value.
- Accounts and notes receivable (including long-term and related parties): The carrying amount reported on the balance sheet approximates fair value. The valuation technique and methods used to estimate the fair value of the current portion of fixed-rate related party loans is consistent with Loans and advances related parties.
- Loans and advances related parties: The carrying amount of floating-rate loans approximates fair value. The fair value of fixed-rate loan activity is measured using market observable data and is categorized as Level 2 in the fair value hierarchy. See Note 6 Investments, Loans and Long-Term Receivables, for additional information.
- Accounts payable (including related parties) and floating-rate debt: The carrying amount of accounts payable and floating-rate debt reported on the balance sheet approximates fair value. The valuation technique and methods used to estimate the fair value of the current portion of the joint venture acquisition obligation is consistent with the methodology below.
- Fixed-rate debt: The estimated fair value of fixed-rate debt is measured using prices available from a pricing service that is corroborated by market data; therefore, these liabilities are categorized as Level 2 in the fair value hierarchy.
- Joint venture acquisition obligation related party: Fair value is estimated based on the net present value of the future cash flows as a Level 2 fair value, discounted at December 31, 2012, and December 31, 2011, effective yield rates of 0.7 percent and 1.24 percent, respectively, 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 12 Joint Venture Acquisition Obligation, for additional information.

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The following table summarizes the net fair value of financial instruments (i.e., adjusted where the right of setoff exists for commodity derivatives):

		Millions of Dollars			
		Carrying Amount		Fair Value	
		2012	2011	**2012**	2011
Financial assets					
Deferred compensation investments	**$**	**305**	336	**305**	336
Commodity derivatives		**221**	814	**221**	814
Total loans and advances related parties		**1,697**	1,793	**1,916**	1,994
Financial liabilities					
Total debt, excluding capital leases		**21,709**	22,592	**26,349**	27,065
Total joint venture acquisition obligation		**3,582**	4,314	**3,968**	4,820
Commodity derivatives		**199**	446	**199**	446

At December 31, 2012, commodity derivative assets and liabilities appear net of $29 million of obligations to return cash collateral and $16 million of rights to reclaim cash collateral, respectively. At December 31, 2011, commodity derivative assets and liabilities appear net of no obligations to return cash collateral and $244 million of rights to reclaim cash collateral.

Note 17 Equity

Common Stock

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

	Shares		
	2012	2011	2010
Issued			
Beginning of year	**1,749,550,587**	1,740,529,279	1,733,345,558
Distributed under benefit plans	**12,697,362**	9,021,308	7,183,721
End of year	**1,762,247,949**	1,749,550,587	1,740,529,279
Held in Treasury			
Beginning of year	**463,880,628**	272,873,537	208,346,815
Repurchase of common stock	**79,904,400**	155,453,382	64,526,722
Distributed under benefit plans	**(1,554,355)**	(475,696)	-
Transfer from grantor trust	**-**	36,029,405	-
End of year	**542,230,673**	463,880,628	272,873,537
Held in Grantor Trusts			
Beginning of year	**-**	36,890,375	38,742,261
Repurchase of common stock	**-**	(157,470)	-
Distributed under benefit plans	**-**	(703,500)	(1,776,873)
Transfer to treasury stock	**-**	(36,029,405)	-
Other	**-**	-	(75,013)

End of year	**-**	-	36,890,375

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Preferred Stock

We have authorized 500 million shares of preferred stock, par value $.01 per share, none of which was issued or outstanding at December 31, 2012 or 2011.

Noncontrolling Interests

At December 31, 2012 and 2011, we had outstanding $440 million and $510 million, respectively, of equity in less-than-wholly owned consolidated subsidiaries held by noncontrolling interest owners. At December 31, 2012, the entire amount was related to Darwin LNG, an operating joint venture we control, located in Australia s Northern Territory. At December 31, 2011, $482 million was related to Darwin LNG and $28 million was related to discontinued operations.

Note 18 Non-Mineral Leases

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

At December 31, 2012, future minimum rental payments due under noncancelable leases were:

		Millions of Dollars
2013	$	477
2014		580
2015		380
2016		314
2017		110
Remaining years		290
Total		2,151
Less income from subleases		24
Net minimum operating lease payments	$	2,127

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

		Millions of Dollars		
		2012	2011	2010
Total rentals*	**$**	**282**	304	267
Less sublease rentals		**(15)**	(14)	(14)
	$	**267**	290	253

**Includes $3 million, $29 million and $16 million of contingent rentals in 2012, 2011 and 2010, respectively. Contingent rentals primarily are related to drilling equipment and are based on usage or volume of product sold.*

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Note 19 Employee Benefit Plans

Pension and Postretirement Plans

In connection with the separation of the Downstream business, ConocoPhillips entered into an Employee Matters Agreement with Phillips 66, see Note 2 Discontinued Operations, which provides that employees of Phillips 66 no longer participate in benefit plans sponsored or maintained by ConocoPhillips as of the separation date. Upon separation, the ConocoPhillips pension and postretirement plans transferred assets and obligations to the Phillips 66 plans resulting in a net decrease in sponsored pension and postretirement plan obligations of $1,127 million. Additionally, as a result of the transfer of unrecognized losses to Phillips 66, deferred income taxes and other comprehensive income decreased $335 million and $570 million, respectively.

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	
		2012		2011		**2012**	2011
		U.S.	**Int l.**	U.S.	Int l.		
Change in Benefit Obligation							
Benefit obligation at January 1	$	**6,175**	**3,484**	5,539	3,206	**926**	862
Service cost		**170**	**91**	225	98	**6**	10
Interest cost		**186**	**152**	247	178	**33**	42
Plan participant contributions		**-**	**7**	-	5	**23**	23
Government subsidy		**-**	**-**	-	-	**-**	4
Separation of Downstream business		**(2,464)**	**(653)**	-	-	**(199)**	-
Plan amendments		**-**	**-**	-	(53)	**-**	35
Actuarial loss		**735**	**297**	642	195	**47**	20
Benefits paid		**(577)**	**(113)**	(478)	(116)	**(72)**	(68)
Foreign currency exchange rate change		**-**	**173**	-	(29)	**1**	(2)
Benefit obligation at December 31*	$	**4,225**	**3,438**	6,175	3,484	**765**	926
**Accumulated benefit obligation portion of above at December 31:*	*$*	***3,710***	***2,972***	*5,363*	*2,939*		
Change in Fair Value of Plan Assets							
Fair value of plan assets at January 1	$	**4,149**	**2,722**	3,890	2,581	**-**	-
Actual return on plan assets		**509**	**267**	64	53	**-**	-
Company contributions		**363**	**204**	673	226	**49**	41
Plan participant contributions		**-**	**7**	-	5	**23**	23
Government subsidy		**-**	**-**	-	-	**-**	4
Separation of Downstream business		**(1,712)**	**(479)**	-	-	**-**	-
Benefits paid		**(577)**	**(113)**	(478)	(116)	**(72)**	(68)
Foreign currency exchange rate change		**-**	**152**	-	(27)	**-**	-
Fair value of plan assets at December 31	$	**2,732**	**2,760**	4,149	2,722	**-**	-
Funded Status	$	**(1,493)**	**(678)**	(2,026)	(762)	**(765)**	(926)

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	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2012		2011		**2012**	2011
	U.S.	**Int l.**	U.S.	Int l.		
Amounts Recognized in the Consolidated Balance Sheet at December 31						
Noncurrent assets	$ **-**	**94**	-	94	**-**	-
Current liabilities	**(21)**	**(8)**	(118)	(5)	**(54)**	(62)
Noncurrent liabilities	**(1,472)**	**(764)**	(1,908)	(851)	**(711)**	(864)
Total recognized	$ **(1,493)**	**(678)**	(2,026)	(762)	**(765)**	(926)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**3.55 %**	**4.50**	4.30	4.90	**3.55**	4.40
Rate of compensation increase	**4.75**	**4.45**	4.25	4.30	**-**	-
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount rate	**4.00 %**	**4.95**	4.65	5.40	**4.25**	5.00
Expected return on plan assets	**7.00**	**6.10**	7.00	6.40	**-**	-
Rate of compensation increase	**4.50**	**4.50**	4.00	4.10	**-**	-

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

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

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2012		2011		**2012**	2011
	U.S.	**Int l.**	U.S.	Int l.		
Unrecognized net actuarial loss (gain)	$ **1,509**	**758**	2,240	705	**29**	(26)
Unrecognized prior service cost (credit)	**28**	**(60)**	52	(78)	**(12)**	(13)

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		Millions of Dollars					
		Pension Benefits				Other Benefits	
		2012		2011		**2012**	2011
		U.S.	**Int l.**	U.S.	Int l.		
Sources of Change in Other Comprehensive Income							
Net loss arising during the period	$	**(450)**	**(206)**	(858)	(307)	**(48)**	(20)
Separation of Downstream business		**810**	**94**	-	-	**(7)**	-
Amortization of (gain) loss included in income*		**371**	**59**	185	46	**-**	(5)
Net change during the period	$	**731**	**(53)**	(673)	(261)	**(55)**	(25)
Prior service (cost) credit arising during the period	$	**-**	**2**	-	53	**-**	(34)
Separation of Downstream business		**17**	**(12)**	-	-	**3**	-
Amortization of prior service cost (credit) included in income		**7**	**(8)**	9	-	**(4)**	(7)
Net change during the period	$	**24**	**(18)**	9	53	**(1)**	(41)

** Includes settlement losses recognized during the period.*

Amounts included in accumulated other comprehensive income at December 31, 2012, that are expected to be amortized into net periodic postretirement cost during 2013 are provided below:

	Millions of Dollars		
	Pension Benefits		Other Benefits
	U.S.	**Int l.**	
Unrecognized net actuarial loss	**$ 151**	**76**	**3**
Unrecognized prior service cost (credit)	**6**	**(8)**	**(4)**

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 $6,278 million, $5,602 million, and $4,537 million, respectively, at December 31, 2012, and $8,481 million, $7,377 million, and $6,098 million, respectively, at December 31, 2011.

For our unfunded nonqualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $525 million and $382 million, respectively, at December 31, 2012, and were $499 million and $374 million, respectively, at December 31, 2011.

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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		
	2012		2011		2010		**2012**	2011	2010
	U.S.	**Int l.**	U.S.	Int l.	U.S.	Int l.			
Components of Net Periodic Benefit Cost									
Service cost	**$ 170**	**91**	225	98	229	90	**6**	10	11
Interest cost	**186**	**152**	247	178	260	169	**33**	42	46
Expected return on plan assets	**(223)**	**(158)**	(280)	(175)	(224)	(147)	**-**	-	-
Amortization of prior service cost (credit)	**7**	**(8)**	9	-	10	2	**(4)**	(7)	3
Recognized net actuarial loss (gain)	**191**	**59**	165	46	167	55	**-**	(5)	(7)
Net periodic benefit cost	**$ 331**	**136**	366	147	442	169	**35**	40	53

In addition to the above, we recognized pension settlement losses of $181 million (including $24 million in discontinued operations) in 2012 and $21 million in 2011. None was recognized in 2010. In 2012, lump-sum benefit payments from the U.S. qualified pension plan exceeded the sum of service and interest costs for that plan and led to an increase in settlement losses.

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

We have multiple nonpension postretirement benefit plans for health and life insurance. The health care plans are contributory and subject to various cost sharing features, with participant and company contributions adjusted annually; the life insurance plans are noncontributory. The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 7.5 percent in 2012 that declines to 5 percent by 2023. A one-percentage-point change in the assumed health care cost trend rate would be immaterial to ConocoPhillips.

Plan Assets We follow a policy of broadly diversifying pension plan assets across asset classes, investment managers, and individual holdings. As a result, our plan assets have no significant concentrations of credit risk. Asset classes that are considered appropriate include U.S. equities, non-U.S. equities, U.S. fixed income, non-U.S. fixed income, real estate and private equity investments. Plan fiduciaries may consider and add other asset classes to the investment program from time to time. The target allocations for plan assets are 59 percent equity securities, 37 percent debt securities and 4 percent real estate. Generally, the plan investments are publicly traded, therefore minimizing liquidity risk in the portfolio.

The following is a description of the valuation methodologies used for the pension plan assets. There have been no changes in the methodologies used at December 31, 2012 and 2011.

Fair values of equity securities and government debt securities categorized in Level 1 are primarily based on quoted market prices. Fair values of corporate debt securities, agency and mortgage-backed securities and government debt securities categorized in Level 2 are estimated using recently executed transactions and quoted market prices. If there have been no market transactions in a particular fixed income security, its fair value is calculated by pricing models that benchmark the security against other securities with actual market prices. When observable quoted market prices are not available, fair value is based on

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pricing models that use something other than actual market prices (e.g., observable inputs such as benchmark yields, reported trades and issuer spreads for similar securities), and these securities are categorized in Level 3 of the fair value hierarchy.
Fair values of investments in common/collective trusts are determined by the issuer of each fund based on the fair value of the underlying assets.
Fair values of mutual funds are based on quoted market prices, which represent the net asset value of shares held.
Cash is valued at cost, which approximates fair value. Fair values of international cash equivalents categorized in Level 2 are valued using observable yield curves, discounting and interest rates. U.S. cash balances held in the form of short-term fund units that are redeemable at the measurement date are categorized as Level 2.
Fair values of exchange-traded derivatives classified in Level 1 are based on quoted market prices. For other derivatives classified in Level 2, the values are generally calculated from pricing models with market input parameters from third-party sources.
Private equity funds are valued at net asset value as determined by the issuer based on the fair value of the underlying assets.
Fair values of insurance contracts are valued at the present value of the future benefit payments owed by the insurance company to the plans participants.
Fair values of real estate investments are valued using real estate valuation techniques and other methods that include reference to third-party sources and sales comparables where available.
A portion of U.S. pension plan assets is held as a participating interest in an insurance annuity contract, which is calculated as the market value of investments held under this contract, less the accumulated benefit obligation covered by the contract. The participating interest is classified as Level 3 in the fair value hierarchy, as the fair value is determined via a combination of quoted market prices, recently executed transactions, and an actuarial present value computation for contract obligations. At December 31, 2012, the participating interest in the annuity contract was valued at $133 million and consisted of $358 million in debt securities, less $225 million for the accumulated benefit obligation covered by the contract. At December 31, 2011, the participating interest in the annuity contract was valued at $144 million and consisted of $391 million in debt securities, less $247 million for the accumulated benefit obligation covered by the contract. The net change from 2011 to 2012 is due to a decrease in the fair value of the underlying investments of $33 million and a decrease in the present value of the contract obligation of $22 million. The participating interest is not available for meeting general pension benefit obligations in the near term. No future company contributions are required and no new benefits are being accrued under this insurance annuity contract.

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

	Millions of Dollars							
	U.S.				International			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
2012								
Equity Securities								
U.S.	**$ 875**	**-**	**-**	**875**	**443**	**-**	**-**	**443**
International	**587**	**-**	**-**	**587**	**381**	**-**	**-**	**381**
Common/collective trusts	**-**	**472**	**-**	**472**	**-**	**195**	**-**	**195**
Mutual funds	**-**	**-**	**-**	**-**	**319**	**-**	**-**	**319**
Debt Securities								
Government	**146**	**54**	**-**	**200**	**496**	**-**	**-**	**496**
Corporate	**-**	**306**	**2**	**308**	**-**	**155**	**1**	**156**
Agency and mortgage-backed securities	**-**	**59**	**-**	**59**	**-**	**29**	**-**	**29**
Common/collective trusts	**-**	**-**	**-**	**-**	**-**	**314**	**-**	**314**
Mutual funds	**-**	**-**	**-**	**-**	**155**	**-**	**-**	**155**
Cash and cash equivalents	**-**	**94**	**-**	**94**	**22**	**18**	**-**	**40**
Private equity funds	**-**	**-**	**4**	**4**	**-**	**-**	**18**	**18**
Derivatives	**-**	**1**	**-**	**1**	**10**	**13**	**-**	**23**
Real estate	**-**	**-**	**-**	**-**	**-**	**-**	**183**	**183**
Total*	**$ 1,608**	**986**	**6**	**2,600**	**1,826**	**724**	**202**	**2,752**

** Excludes the participating interest in the insurance annuity contract with a net asset value of $133 million and net receivables related to security transactions of $7 million.*

	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
2011								
Equity Securities								
U.S.	$ 1,251	-	-	1,251	413	-	-	413
International	803	-	-	803	413	-	-	413
Common/collective trusts	-	634	-	634	-	234	-	234
Mutual funds	-	-	-	-	246	-	-	246
Debt Securities								
Government	311	81	-	392	532	-	-	532
Corporate	-	551	3	554	-	122	1	123
Agency and mortgage-backed securities	-	105	-	105	-	43	-	43
Common/collective trusts	-	-	-	-	-	346	-	346
Mutual funds	-	-	-	-	130	-	-	130
Cash and cash equivalents	-	249	-	249	32	26	-	58
Private equity funds	-	-	4	4	-	-	13	13
Derivatives	-	-	-	-	-	11	-	11
Insurance contracts	-	-	-	-	-	-	15	15
Real estate	-	-	-	-	-	-	139	139
Total*	$ 2,365	1,620	7	3,992	1,766	782	168	2,716

**Excludes the participating interest in the insurance annuity contract with a net asset value of $144 million and net receivables related to security transactions of $19 million.*

Level 3 activity was not material.

Our funding policy for U.S. plans is to contribute at least the minimum required by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code of 1986, as amended. Contributions to foreign plans are dependent upon local laws and tax regulations. In 2013, we expect to contribute approximately $275

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million to our domestic qualified and nonqualified pension and postretirement benefit plans and $210 million to our international qualified and nonqualified pension and postretirement benefit plans.

The following benefit payments, which are exclusive of amounts to be paid from the insurance 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.	
2013	$ 375	118	62
2014	370	126	63
2015	366	137	63
2016	370	141	63
2017	399	146	63
2018-2022	2,067	897	291

Defined Contribution Plans

Most U.S. employees are eligible to participate in the ConocoPhillips Savings Plan (CPSP). Employees can deposit up to 75 percent of their eligible pay up to the statutory limit ($17,000 in 2012) in the thrift feature of the CPSP to a choice of approximately 38 investment funds. Through 2012, ConocoPhillips matched contribution deposits, up to 1.25 percent of eligible pay. Company contributions charged to expense related to continuing and discontinued operations for the CPSP and predecessor plans, excluding the stock savings feature (discussed below), were $16 million in 2012, $25 million in 2011, and $24 million in 2010.

The stock savings feature of the CPSP is a leveraged employee stock ownership plan. Through 2012, employees could elect to participate in the stock savings feature by contributing 1 percent of eligible pay and receiving an allocation of shares of common stock proportionate to the amount of contribution.

In 1990, the Long-Term Stock Savings Plan of Phillips Petroleum Company (now the stock savings feature of the CPSP) borrowed funds that were used to purchase previously unissued shares of company common stock. Since the Company guarantees the CPSP s borrowings, the unpaid balance is reported as a liability of the Company and unearned compensation is shown as a reduction of common stockholders equity. Dividends on all shares are charged against retained earnings. The debt is serviced by the CPSP from company contributions and dividends received on certain shares of common stock held by the plan, including all unallocated shares. The shares held by the stock savings feature of the CPSP are released for allocation to participant accounts based on debt service payments on CPSP borrowings. In 2012, the final debt service payment was made and all remaining unallocated shares were released for allocation to participant accounts.

We recognize interest expense as incurred and compensation expense based on the fair 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 continuing and discontinued operations to the stock savings feature of $104 million, $77 million and $92 million in 2012, 2011 and 2010, respectively, all of which was compensation expense. In 2012 and 2011, we made cash contributions to the CPSP of $5 million and $4 million, respectively. No cash contributions were made in 2010. In 2011 and 2010, we contributed 660,755 shares and 1,776,873 shares, respectively, of company common stock from the Compensation and Benefits Trust. The shares had a fair value of $84 million and $103 million, respectively. In 2012 and 2011, we contributed 1,554,355 and 475,696 shares, respectively, of company common stock from treasury stock. Dividends used to service debt were $10 million, $45 million and $41 million in 2012, 2011 and 2010, respectively. These dividends reduced the amount of compensation expense recognized each period. Interest incurred on the CPSP debt in 2012, 2011 and 2010 was $0.1 million, $1 million and $2 million, respectively.

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

	2012	2011
Unallocated shares	**-**	811,963
Allocated shares	**11,246,660**	19,315,372
Total shares	**11,246,660**	20,127,335

The fair value of unallocated shares at December 31, 2011 was $59 million.

Starting in 2013, employees who participate in the CPSP and contribute 1 percent of their eligible pay will receive a 9 percent company cash match. CPSP will no longer have a stock savings feature.

We have several defined contribution plans for our international employees, each with its own terms and eligibility depending on location. Total compensation expense related to continuing and discontinued operations recognized for these international plans was approximately $56 million in 2012 and 2011 and $52 million in 2010.

Share-Based Compensation Plans

The 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (the Plan) was approved by shareholders in May 2011. Over its 10-year life, the Plan allows the issuance of up to 100 million shares of our common stock for compensation to our employees and directors; however, as of the effective date of the Plan, (i) any shares of common stock available for future awards under the prior plans and (ii) any shares of common stock represented by awards granted under the prior plans that are forfeited, expire or are canceled without delivery of shares of common stock or which result in the forfeiture of shares of common stock back to the company shall be available for awards under the Plan, and no new awards shall be granted under the prior plans. Of the 100 million shares available for issuance under the Plan, no more than 40 million shares of common stock are available for incentive stock options, and no more than 40 million shares are available for awards in stock.

Our share-based compensation programs generally provide accelerated vesting (i.e., a waiver of the remaining period of service required to earn an award) for awards held by employees at the time of their retirement. We recognize share-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award); or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement, but not less than six months, as this is the minimum period of time required for an award to not be subject to forfeiture. Some of our share-based awards vest ratably (i.e., portions of the award vest at different times) while some of our awards cliff vest (i.e., all of the award vests at the same time). 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.

Separation-Related Adjustments In connection with the separation of the Downstream business on April 30, 2012, ConocoPhillips entered into an Employee Matters Agreement with Phillips 66, see Note 2 Discontinued Operations, which provides that employees of Phillips 66 no longer participate in benefit plans sponsored or maintained by ConocoPhillips. Pursuant to the Employee Matters Agreement, we made certain adjustments, using volumetric weighted-average prices for the 4-day period immediately prior to and immediately following the separation, to the exercise price and number of our share-based compensation awards, with the intention of preserving the intrinsic value of the awards immediately prior to the separation. These adjustments are summarized as follows and are reflected in the activity tables below:

Outstanding options to purchase common shares of ConocoPhillips stock that were exercisable prior to the separation were adjusted so that the holders of the options would then hold one option to purchase common shares of Phillips 66 stock for every two adjusted stock options to purchase common shares of ConocoPhillips stock following the separation.

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Nonexercisable stock options and restricted stock units were converted to those of the entity where the employee holding them is working immediately post-separation. Therefore, nonexercisable stock options to purchase common shares of ConocoPhillips stock and ConocoPhillips restricted stock units held by an employee who separated with the Downstream business were surrendered as a result of the separation.

In addition, former employee holders and a specified group of holders of stock options and restricted stock units who retired or terminated employment upon or shortly after the separation received both adjusted ConocoPhillips awards and Philips 66 awards.

ConocoPhillips restricted stock and performance share units awarded for completed performance periods under the Performance Share Program, as well as vested restricted stock units held by current or former directors, were adjusted to provide holders one restricted share or restricted stock unit of Phillips 66 stock for every two restricted shares or restricted stock units of ConocoPhillips stock.

The separation-related adjustments did not have a material impact on either compensation expense or the potentially dilutive securities to be considered in the calculation of diluted earnings per share of common stock.

Compensation Expense Total share-based compensation expense recognized in income related to continuing and discontinued operations and the associated tax benefit for the years ended December 31 were as follows:

		Millions of Dollars		
		2012	2011	2010
Compensation cost	$	**321**	246	211
Tax benefit		**118**	86	78

Stock Options Stock options granted under the provisions of the Plan and prior 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 certain employees already eligible for retirement vest within 6 months of the grant date, but those options do not become exercisable until the end of the normal vesting period.

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The following summarizes our stock option activity for the year ended December 31, 2012:

	Options	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Millions of Dollars Aggregate Intrinsic Value
Outstanding at December 31, 2011	24,372,051	$ 45.73		
Granted	**2,335,600**	**71.87**	**$ 15.69**	
Exercised	**(9,735,269)**	**25.34**		**$ 469**
Forfeited	**(462,862)**	**55.76**		
Expired or canceled	**(32,048)**	**65.65**		
Options surrendered, as a result of the separation	**(1,045,820)**	**68.01**		
Options granted in conversion, as a result of the separation	**865,353**	**45.92**		
Outstanding at December 31, 2012	**16,297,005**	**$ 43.67**		
Vested at December 31, 2012	**14,348,278**	**$ 42.58**		**$ 219**
Exercisable at December 31, 2012	**12,725,857**	**$ 41.90**		**$ 204**

The weighted-average remaining contractual term of vested options and exercisable options at December 31, 2012, was 4.92 years and 4.52 years, respectively. The weighted-average grant date fair value of stock option awards granted during 2011 and 2010 was $16.70 and $11.70, respectively. The aggregate intrinsic value of options exercised during 2011 and 2010 was $416 million and $183 million, respectively.

During 2012, we received $294 million in cash and realized a tax benefit related to continuing and discontinued operations of $153 million from the exercise of options. At December 31, 2012, the remaining unrecognized compensation expense from unvested options was $9 million, which will be recognized over a weighted-average period of 1.66 years, the longest period being 2.11 years.

The fair market values of the options granted over the past three years were measured on the date of grant using the Black-Scholes option-pricing model. During 2012, all stock option grants occurred prior to the separation of the Downstream business. The weighted-average assumptions used were as follows:

	2012	2011	2010
Assumptions used			
Risk-free interest rate	**1.62 %**	3.10	3.23
Dividend yield	**4.00 %**	4.00	4.00
Volatility factor	**33.30 %**	33.40	33.80
Expected life (years)	**7.42**	6.87	6.65

The ranges in the assumptions used were as follows:

	2012		2011		2010	
	High	**Low**	High	Low	High	Low

Ranges used						
Risk-free interest rate	**1.62 %**	**1.62**	3.10	3.10	3.23	3.23
Dividend yield	**4.00**	**4.00**	4.00	4.00	4.00	4.00
Volatility factor	**33.30**	**33.30**	33.40	33.40	33.80	33.80

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Expected volatility above was based on historical volatility of the company s stock using ConocoPhillips end-of-week closing stock prices over a period commensurate with 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. Due to the separation of our Downstream business, our calculation of expected volatility for grants of options in 2013 will be based on a three-year average historical stock price volatility of a group of peer companies.

Stock Unit Program Generally, restricted stock units are granted annually under the provisions of the Plan and 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. Beginning with restricted stock units granted in 2013, the general vesting schedule will accelerate with units vesting 36 months from the date of grant. In addition, beginning in 2012, restricted stock units are granted under the Plan for a variable long-term incentive program, with one-third of units vesting in 12 months, one-third vesting in 24 months, and the final one-third vesting 36 months from the date of grant. Restricted stock units are also granted ad hoc to attract or retain key personnel, and the terms and conditions under which these restricted stock units vest vary by award. Upon vesting, the units are settled by issuing one share of ConocoPhillips common stock per unit. Units awarded to certain employees already eligible for retirement vest six months from 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 retained earnings. The grant date fair value of these units is deemed equal to the average ConocoPhillips stock price on the date of grant. The grant date fair market value of units that do not receive a dividend equivalent while unvested is deemed equal to the average ConocoPhillips stock price on the grant date, less the net present value of the dividends that will not be received.

The following summarizes our stock unit activity for the year ended December 31, 2012:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2011	8,728,958	$ 55.41	
Granted	**5,911,369**	**60.62**	
Forfeited	**(319,691)**	**52.70**	
Issued	**(2,755,134)**		**$ 187**
Awards surrendered, as a result of the separation	**(2,368,520)**	**59.56**	
Awards granted in conversion, as a result of the separation	**2,280,140**	**45.00**	
Outstanding at December 31, 2012	**11,477,122**	**$ 46.58**	
Not Vested at December 31, 2012	**8,659,344**	**$ 47.63**	

At December 31, 2012, the remaining unrecognized compensation cost from the unvested units was $279 million, which will be recognized over a weighted-average period of 2.54 years, the longest period being 7.34 years. The weighted-average grant date fair value of stock unit awards granted during 2011 and 2010 was $67.54 and $46.38, respectively. The total fair value of stock units issued during 2011 and 2010 was $109 million and $79 million, respectively.

Performance Share Program Under the Plan, we also annually grant to senior management restricted performance share units (PSUs) that do not vest until either (i) with respect to awards for performance periods beginning before 2009, the employee becomes eligible for retirement by reaching age 55 with five years of service or (ii) with respect to awards for performance periods beginning in 2009, five years after the grant date of the award (although recipients can elect to defer the lapsing of restrictions until retirement after reaching age 55 with five years of service), so we recognize compensation expense for these awards beginning on the date of grant and ending on the date the PSUs are scheduled to vest. Since these awards are authorized three years prior to the grant date, for employees eligible for such retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. These PSUs are settled by issuing one share of ConocoPhillips common stock per unit. Until issued as stock, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to retained earnings. In its current form, the first grant of PSUs under this program was in 2006.

During 2012, performance share awards previously authorized but not yet granted prior to the separation with our Downstream business were granted and a pro-rata number of performance share stock units were awarded to the employee participants.

The following summarizes our Performance Share Program activity for the year ended December 31, 2012:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2011	3,517,761	$ 64.35	
Granted	**2,812,828**	**74.16**	
Forfeited	**(4,893)**	**63.18**	
Issued	**(1,141,412)**		**$ 71**
Outstanding at December 31, 2012	**5,184,284**	**$ 51.54**	
Not Vested at December 31, 2012	**1,628,706**	**$ 52.79**	

At December 31, 2012, the remaining unrecognized compensation cost from unvested performance share awards was $45 million, which includes $11 million related to unvested performance share awards tied to Phillips 66 stock held by ConocoPhillips employees, which will be recognized over a weighted-average period of 3.83 years, the longest period being 8.19 years. The weighted-average grant date fair value of performance share units granted during 2011 and 2010 was $70.57 and $48.39, respectively. The total fair value of performance share units issued during 2011 and 2010 was $37 million and $12 million, respectively.

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 year ended December 31, 2012:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2011	2,587,915	$ 33.49	
Granted	**86,701**	**63.54**	
Forfeited	**(205,701)**	**24.20**	
Issued	**(1,336,359)**		**$ 73**
Outstanding at December 31, 2012	**1,132,556**	**$ 27.34**	
Not Vested at December 31, 2012	**-**		

At December 31, 2012, all outstanding restricted stock and restricted stock units were fully vested and there was no remaining compensation cost to be recorded. The weighted-average grant date fair value of restricted shares and units granted during 2011 and 2010 was $70.25 and $53.33, respectively. The total fair value of restricted shares and units issued during 2011 and 2010 was $10 million and $9 million, respectively.

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Note 20 Income Tax

Income taxes charged to income from continuing operations were:

	Millions of Dollars		
	2012	2011	2010
Income Taxes			
Federal			
Current	$ **63**	1,066	1,231
Deferred	**624**	285	148
Foreign			
Current	**6,255**	6,400	7,050
Deferred	**744**	48	(1,120)
State and local			
Current	**231**	308	255
Deferred	**25**	101	6
	$ **7,942**	8,208	7,570

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	
	2012	2011
Deferred Tax Liabilities		
PP&E and intangibles	$ **18,826**	21,159
Investment in joint ventures	**872**	2,943
Inventory	**76**	-
Partnership income deferral	**343**	363
Other	**793**	703
Total deferred tax liabilities	**20,910**	25,168
Deferred Tax Assets		
Benefit plan accruals	**1,760**	2,063
Asset retirement obligations and accrued environmental costs	**3,954**	4,254
Inventory	**-**	43
Deferred state income tax	**77**	299
Other financial accruals and deferrals	**544**	618
Loss and credit carryforwards	**2,062**	1,608
Other	**398**	692
Total deferred tax assets	**8,795**	9,577
Less valuation allowance	**(1,345)**	(1,487)
Net deferred tax assets	**7,450**	8,090
Net deferred tax liabilities	$ **13,460**	17,078

Current assets, long-term assets, current liabilities and long-term liabilities included deferred taxes of $461 million, $222 million, $958 million and $13,185 million, respectively, at December 31, 2012, and $788 million, $183 million, $9 million and $18,040 million, respectively, at December 31, 2011. The reduction in net deferred tax liabilities from 2011 to 2012 was primarily due to the separation of our Downstream business. See Note 2 Discontinued Operations for more information.

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We have loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2013 and 2032 with some carryovers having indefinite carryforward periods.

Valuation allowances have been established to reduce deferred tax assets to an amount that will, more likely than not, be realized. During 2012, valuation allowances decreased a total of $142 million. This reflects decreases of $516 million primarily related to the separation of our Downstream business, asset relinquishment and utilization of loss carryforwards, partially offset by increases of $374 million, primarily related to U.S. foreign tax credit and foreign and state loss carryforwards. Based on our historical taxable income, expectations for the future, and available tax-planning strategies, management expects remaining net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as offsets to the tax consequences of future taxable income.

At December 31, 2012 and 2011, income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $2,286 million and $4,227 million, respectively. Deferred income taxes have not been provided on this income, as we do not plan to initiate any action that would require the payment of income taxes. It is not practicable to estimate the amount of additional tax that might be payable on this foreign income if distributed.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2012, 2011 and 2010:

	Millions of Dollars		
	2012	2011	2010
Balance at January 1	**$ 1,071**	1,125	1,208
Additions based on tax positions related to the current year	**98**	46	63
Additions for tax positions of prior years	**48**	145	344
Reductions for tax positions of prior years	**(206)**	(35)	(199)
Settlements	**(108)**	(206)	(215)
Lapse of statute	**(31)**	(4)	(76)
Balance at December 31	**$ 872**	1,071	1,125

Included in the balance of unrecognized tax benefits for 2012, 2011 and 2010 were $650 million, $815 million and $914 million, respectively, which, if recognized, would impact our effective tax rate.

At December 31, 2012, 2011 and 2010, accrued liabilities for interest and penalties totaled $129 million, $141 million and $171 million, respectively, net of accrued income taxes. Interest and penalties resulted in a benefit to earnings in 2012 of $9 million, a charge to earnings in 2011 of $10 million, and a benefit to earnings in 2010 of $2 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 are generally complete as follows: United Kingdom (2009), Canada (2005), United States (2008) and Norway (2011). Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion in the many jurisdictions in which we operate around the world. As a consequence, the balance in unrecognized tax benefits can be expected to fluctuate from period to period. It is reasonably possible such changes could be significant when compared with our total unrecognized tax benefits, but the amount of change is not estimable.

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The amounts of U.S. and foreign income from continuing income 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		
	2012	2011	2010	**2012**	2011	2010
Income before income taxes from continuing operations						
United States	$ **4,070**	4,762	3,872	**26.4%**	30.9	21.7
Foreign	**11,353**	10,634	14,003	**73.6**	69.1	78.3
	$ **15,423**	15,396	17,875	**100.0%**	100.0	100.0
Federal statutory income tax	$ **5,398**	5,389	6,256	**35.0%**	35.0	35.0
Foreign taxes in excess of federal statutory rate	**2,878**	2,658	1,238	**18.6**	17.3	6.9
Capital loss benefit	**(461)**	-	-	**(3.0)**	-	-
Federal manufacturing deduction	**(52)**	(73)	(75)	**(0.3)**	(0.5)	(0.4)
State income tax	**166**	266	170	**1.1**	1.7	0.9
Other	**13**	(32)	(19)	**0.1**	(0.2)	(0.1)
	$ **7,942**	8,208	7,570	**51.5%**	53.3	42.3

The change in the effective tax rate from 2011 to 2012 was primarily due to the effect of the Company s asset disposition program, partially offset by higher income in high tax jurisdictions in 2012. The change in the effective tax rate from 2010 to 2011 was primarily due to tax benefits associated with asset dispositions occurring in 2010.

In the United Kingdom, legislation was enacted on July 17, 2012, restricting corporate tax relief on decommissioning costs to 50 percent, retroactively effective from March 21, 2012. Our 2012 earnings were reduced by $192 million due to remeasurement of deferred tax balances as of the effective date.

In the United Kingdom, legislation was enacted on July 19, 2011, which increased the supplementary corporate tax rate applicable to U.K. Upstream activity from 20 to 32 percent, retroactively effective from March 24, 2011. This resulted in the overall U.K. corporate rate increasing from 50 percent to 62 percent. The enactment resulted in increased U.K. corporate income tax expense of $316 million in 2011. This is comprised of $106 million due to remeasurement of U.K. deferred tax liabilities, and $210 million to reflect the new rate from March 24, 2011, through December 31, 2011.

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

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Note 21 Accumulated Other Comprehensive Income

Accumulated other comprehensive income in the equity section of the balance sheet included:

	Millions of Dollars				
	Defined Benefit Plans	Net Unrealized Gain on Securities	Foreign Currency Translation	Hedging	Accumulated Other Comprehensive Income (Loss)
December 31, 2009	$ (1,504)	-	4,736	(7)	3,225
Other comprehensive income	146	158	1,404	-	1,708
December 31, 2010	(1,358)	158	6,140	(7)	4,933
Other comprehensive income (loss)	(613)	(158)	(917)	1	(1,687)
December 31, 2011	(1,971)	-	5,223	(6)	3,246
Other comprehensive income (loss)	**(137)**	**-**	**758**	**6**	**627**
Separation of Downstream business	**683**	**-**	**(469)**	**-**	**214**
December 31, 2012	**$ (1,425)**	**-**	**5,512**	**-**	**4,087**

Note 22 Cash Flow Information

Amounts included in continuing operations for the years ended December 31 were:

	Millions of Dollars		
	2012	2011	2010
Noncash Investing and Financing Activities			
Increase in PP&E related to an increase in asset retirement obligations	**$ 1,010***	182	808
Cash Payments			
Interest	**$ 724**	919	1,120
Income taxes	**8,568**	10,285	8,262
Net Sales (Purchases) of Short-Term Investments			
Short-term investments purchased	**$ (497)**	(6,744)	(982)
Short-term investments sold	**1,094**	7,144	-
	$ 597	400	(982)

**Includes $152 million primarily related to U.K. tax law changes on the deductibility of decommissioning costs.*

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Note 23 Other Financial Information

Amounts included in continuing operations for the years ended December 31 were:

	Millions of Dollars Except Per Share Amounts		
	2012	2011	2010
Interest and Debt Expense			
Incurred			
Debt	**$ 1,170**	1,230	1,401
Other	**154**	212	237
	1,324	1,442	1,638
Capitalized	**(615)**	(488)	(471)
Expensed	**$ 709**	954	1,167
Other Income			
Interest income	**$ 163**	170	135
Other, net	**306**	94	46
	$ 469	264	181
Research and Development Expenditures expensed	**$ 221**	193	172
Shipping and Handling Costs*	**$ 1,338**	1,394	1,369

**Amounts included in production and operating expenses.*

Foreign Currency Transaction (Gains) Losses after-tax			
Alaska	**$ -**	-	-
Lower 48 and Latin America	**-**	-	1
Canada	**5**	(3)	10
Europe	**21**	7	20
Asia Pacific and Middle East	**29**	(23)	(96)
Other International	**1**	3	4
LUKOIL Investment	**-**	(1)	15
Corporate and Other	**2**	(16)	7
	$ 58	(33)	(39)

	Millions of Dollars	
	2012	2011
Properties, Plants and Equipment		
Proved properties	**$ 111,458***	111,044
Unproved properties	**8,257***	7,846
Discontinued operations Downstream business	**-**	23,566

Other	**6,464**	6,753
Gross properties, plants and equipment	**126,179**	149,209
Accumulated depreciation	**(58,916)**	(65,029)
Net properties, plants and equipment	**$ 67,263**	84,180

**Excludes assets held for sale reclassified to prepaid expenses and other current assets, including proved properties of $11,075 million and unproved properties of $234 million.*

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Note 24 Related Party Transactions

We consider our equity method investments to be related parties. Significant transactions with related parties were:

		Millions of Dollars		
		2012	2011	2010
Operating revenues and other income	$	**59**	49	18
Gains on dispositions*		**-**	-	1,149
Purchases		**261**	327	656
Operating expenses and selling, general and administrative expenses		**183**	233	238
Net interest expense**		**38**	61	75

* *During 2010, we sold a portion of our LUKOIL shares under a stock purchase and option agreement with a wholly owned subsidiary of LUKOIL, resulting in a before-tax gain of $1,149 million. Beginning in the fourth quarter of 2010, transactions with LUKOIL and its subsidiaries were no longer considered related party transactions. See Note 5 Assets Held for Sale or Sold, for additional information.*

** *We paid interest to, or received interest from, various affiliates, including FCCL Partnership. See Note 6 Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.*

Note 25 Segment Disclosures and Related Information

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. We manage our operations through six operating segments, which are defined by geographic region: Alaska, Lower 48 and Latin America, Canada, Europe, Asia Pacific and Middle East, and Other International.

On April 30, 2012, our Downstream business was separated into a stand-alone, publicly traded corporation, Phillips 66. In 2012, we also agreed to sell our Nigerian and Algerian businesses and our interest in Kashagan. As such, results for these operations have been reported as discontinued operations in all periods presented. Commodity sales to Phillips 66, which were previously eliminated in consolidation prior to the separation, are now reported as third-party sales. For additional information, see Note 2 Discontinued Operations.

Our LUKOIL Investment represents our prior investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. We completed the divestiture of our entire interest in LUKOIL in the first quarter of 2011.

Corporate and Other represents costs not directly associated with an operating segment, such as most interest expense, corporate overhead, ongoing costs associated with the separation and certain technology activities, net of licensing revenues. Corporate assets include all cash and cash equivalents, short-term investments and restricted cash.

We evaluate performance and allocate resources based on net income attributable to ConocoPhillips. Segment accounting policies are the same as those in Note 1 Accounting Policies. Intersegment sales are at prices that approximate market.

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Analysis of Results by Operating Segment

	Millions of Dollars		
	2012	2011	2010
Sales and Other Operating Revenues			
Alaska	$ **9,502**	9,533	7,462
Lower 48 and Latin America	**19,600**	23,507	21,980
Intersegment eliminations	**(230)**	(283)	(180)
Lower 48 and Latin America	**19,370**	23,224	21,800
Canada	**5,028**	6,270	6,147
Intersegment eliminations	**(475)**	(944)	(797)
Canada	**4,553**	5,326	5,350
Europe	**14,709**	17,119	12,819
Intersegment eliminations	**(72)**	(50)	(17)
Europe	**14,637**	17,069	12,802
Asia Pacific and Middle East	**7,705**	8,665	7,161
Intersegment eliminations	**(41)**	(1)	(1)
Asia Pacific and Middle East	**7,664**	8,664	7,160
Other International	**2,088**	221	1,543
LUKOIL Investment	**-**	-	-
Corporate and Other	**153**	159	98
Consolidated sales and other operating revenues	$ **57,967**	64,196	56,215
Depreciation, Depletion, Amortization and Impairments			
Alaska	$ **520**	578	626
Lower 48 and Latin America	**2,796**	2,228	2,286
Canada	**1,600**	1,758	1,680
Europe	**1,203**	1,405	2,049
Asia Pacific and Middle East	**1,002**	1,063	1,329
Other International	**45**	8	44
LUKOIL Investment	**-**	-	-
Corporate and Other	**94**	108	71
Consolidated depreciation, depletion, amortization and impairments	$ **7,260**	7,148	8,085

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		Millions of Dollars	
	2012	2011	2010
Equity in Earnings of Affiliates			
Alaska	$ **10**	(77)	8
Lower 48 and Latin America	**86**	99	80
Canada	**726**	677	505
Europe	**29**	46	41
Asia Pacific and Middle East	**1,057**	819	(17)
Other International	**6**	(324)	(532)
LUKOIL Investment	**-**	-	1,295
Corporate and Other	**(3)**	(1)	(4)
Consolidated equity in earnings of affiliates	$ **1,911**	1,239	1,376
Income Taxes			
Alaska	$ **1,266**	1,171	1,017
Lower 48 and Latin America	**133**	741	595
Canada	**(252)**	(45)	215
Europe	**4,012**	4,459	3,118
Asia Pacific and Middle East	**1,578**	1,887	1,340
Other International	**1,485**	162	1,170
LUKOIL Investment	**-**	123	505
Corporate and Other	**(280)**	(290)	(390)
Consolidated income taxes	$ **7,942**	8,208	7,570
Net Income Attributable to ConocoPhillips			
Alaska	$ **2,276**	1,984	1,727
Lower 48 and Latin America	**1,029**	1,288	1,029
Canada	**(684)**	91	2,902
Europe	**1,498**	1,830	1,703
Asia Pacific and Middle East	**3,928**	3,032	2,099
Other International	**359**	(377)	(418)
LUKOIL Investment	**-**	239	2,513
Corporate and Other	**(993)**	(960)	(1,304)
Discontinued operations	**1,015**	5,309	1,107
Consolidated net income attributable to ConocoPhillips	$ **8,428**	12,436	11,358
Investments In and Advances To Affiliates			
Alaska	$ **56**	58	143
Lower 48 and Latin America	**1,133**	1,168	1,190
Canada	**9,973**	9,045	8,675
Europe	**242**	195	211
Asia Pacific and Middle East	**12,468**	11,571	11,335
Other International	**61**	339	813
LUKOIL Investment	**-**	-	-
Corporate and Other	**15**	9	-
Discontinued operations	**-**	10,275	9,868
Consolidated investments in and advances to affiliates	$ **23,948**	32,660	32,235

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		Millions of Dollars		
		2012	2011	2010
Total Assets				
Alaska	$	**10,950**	10,723	10,832
Lower 48 and Latin America		**28,895**	25,872	24,213
Canada		**22,308**	20,847	21,168
Europe		**15,562**	12,452	11,335
Asia Pacific and Middle East		**23,721**	22,374	21,853
Other International		**1,418**	1,542	2,050
LUKOIL Investment		**-**	-	1,129
Corporate and Other		**6,823**	8,485	11,974
Discontinued operations		**7,467**	50,935	51,760
Consolidated total assets	$	**117,144**	153,230	156,314
Capital Expenditures and Investments				
Alaska	$	**828**	774	729
Lower 48 and Latin America		**5,251**	3,882	1,790
Canada		**2,184**	1,761	1,356
Europe		**2,860**	2,222	1,190
Asia Pacific and Middle East		**2,430**	2,325	2,157
Other International		**415**	8	127
LUKOIL Investment		**-**	-	-
Corporate and Other		**204**	242	186
Consolidated capital expenditures and investments	$	**14,172**	11,214	7,535
Interest Income and Expense				
Interest income				
Corporate	$	**96**	94	54
Lower 48 and Latin America		**47**	51	54
Asia Pacific and Middle East		**11**	7	8
Other International		**9**	18	19
Interest and debt expense				
Corporate	$	**606**	832	1,027
Canada		**103**	122	140
Sales and Other Operating Revenues by Product				
Crude oil	$	**26,302**	24,237	20,840
Natural gas		**25,163**	29,915	28,550
Natural gas liquids		**2,416**	3,101	2,817
Other*		**4,086**	6,943	4,008
Consolidated sales and other operating revenues by product	$	**57,967**	64,196	56,215

** Includes LNG and bitumen.*

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Geographic Information

	Millions of Dollars					
	Sales and Other Operating Revenues*			Long-Lived Assets**		
	2012	2011	2010	**2012**	2011	2010
United States	$ **28,901**	32,790	29,305	**35,443**	33,750	32,246
Australia***	**3,371**	3,458	2,789	**13,483**	12,572	12,461
Canada	**4,553**	5,326	5,350	**21,304**	20,083	20,439
China	**1,499**	2,154	1,870	**2,408**	2,449	2,656
Indonesia	**2,198**	2,076	1,696	**1,662**	1,726	1,745
Norway	**5,059**	5,755	4,692	**7,288**	5,918	5,664
United Kingdom	**9,578**	11,314	8,110	**4,480**	3,257	2,975
Other foreign countries	**2,808**	1,323	2,403	**5,143**	5,107	5,231
Discontinued operations	**-**	-	-	**-**	31,978	31,372
Worldwide consolidated	$ **57,967**	64,196	56,215	**91,211**	116,840	114,789

**Sales and other operating revenues are attributable to countries based on the location of the operations generating the revenues.*
***Defined as net PP&E plus investments in and advances to affiliated companies.*
****Includes amounts related to the joint petroleum development area with shared ownership held by Australia and Timor-Leste.*

Oil and Gas Operations (Unaudited)

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas, and regulations of the U.S. Securities and Exchange Commission (SEC), we are making certain supplemental disclosures about our oil and gas exploration and production operations.

These disclosures include information about our consolidated oil and gas activities and our proportionate share of our equity affiliates oil and gas activities, covering both those in our operating segments, as well as in our LUKOIL Investment segment. As a result, for periods prior to 2011, amounts reported as equity affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report.

Our proved reserves include estimated quantities related to production sharing contracts (PSCs), which are reported under the economic interest method and are subject to fluctuations in commodity prices; recoverable operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices increase, then our applicable reserve quantities would decline. At December 31, 2012, approximately 9 percent of our total proved reserves were under PSCs, primarily in our Asia Pacific/Middle East geographic reporting area.

Our disclosures by geographic area include the United States, Canada, Europe (primarily Norway and the United Kingdom), Russia, Asia Pacific/Middle East, Africa and Other Areas. Other Areas primarily consists of the Caspian Region.

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

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

During the fourth quarter of 2012, we agreed to sell our interest in Kashagan, and the Algeria and Nigeria businesses, with closing on all three transactions expected by mid-2013. These businesses were considered held for sale at December 31, 2012, and have been reported as discontinued operations. Accordingly, the Results of Operations, Average Sales Prices and Net Production tables included within the supplemental oil and gas disclosures reflect the associated earnings and production as discontinued operations.

In January 2013, we entered into an agreement to sell the majority of our properties in the Cedar Creek Anticline, with closing expected in the first quarter of 2013. At December 31, 2012, the asset was considered held for sale.

The proved reserves associated with all these assets held for sale at December 31, 2012, totaled 364 million barrels of oil equivalent (BOE) and are reflected in the following reserves tables.

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Reserves Governance

The recording and reporting of proved reserves are governed by criteria established by regulations of the SEC and FASB. Proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Proved reserves are further classified as either developed or undeveloped. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

We have a companywide, comprehensive, SEC-compliant internal policy that governs the determination and reporting of proved reserves. This policy is applied by the geologists and reservoir engineers in our Exploration and Production (E&P) business units around the world. As part of our internal control process, each business unit s reserve processes and controls are reviewed annually by an internal team which is headed by the Company s Manager of Reserves Compliance and Reporting. This team, composed of internal reservoir engineers, geologists, finance personnel and a senior representative from DeGolyer and MacNaughton (D&M), reviews the business units reserves for adherence to SEC guidelines and company policy through on-site visits and review of documentation. In addition to providing independent reviews, this internal team also ensures reserves are calculated using consistent and appropriate standards and procedures. This team is independent of business unit line management and is responsible for reporting its findings to senior management and our internal audit group. The team is responsible for communicating our reserves policy and procedures and is available for internal peer reviews and consultation on major projects or technical issues throughout the year. All of our proved reserves held by consolidated companies and our share of equity affiliates have been estimated by ConocoPhillips.

During 2012, our processes and controls used to assess over 90 percent of proved reserves as of December 31, 2012, were reviewed by D&M, a third-party petroleum engineering consulting firm. The purpose of their review was to assess whether the adequacy and effectiveness of our internal processes and controls used to determine estimates of proved reserves are in accordance with SEC regulations. In such review, ConocoPhillips technical staff presented D&M with an overview of the reserves data, as well as the methods and assumptions used in estimating reserves. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, reservoir simulation models, well performance data, operating procedures and relevant economic criteria. Management s intent in retaining D&M to review its processes and controls was to provide objective third-party input on these processes and controls. D&M s opinion was that the general processes and controls employed by ConocoPhillips in estimating its December 31, 2012, proved reserves for the properties reviewed are in accordance with the SEC reserves definitions. D&M s report is included as Exhibit 99 of this Annual Report on Form 10-K.

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The technical person primarily responsible for overseeing the processes and internal controls used in the preparation of the company s reserve estimates is the Manager of Reserves Compliance and Reporting. This individual is a petroleum engineer with a bachelor s degree in civil engineering. He is a member of the Society of Petroleum Engineers (SPE) with over 30 years of oil and gas industry experience, including drilling and production engineering assignments in several field locations. He has held positions of increasing responsibility in reservoir engineering, reserves reporting and compliance, and business management.

Engineering estimates of the quantities of proved reserves are inherently imprecise. See the Critical Accounting Estimates section of Management s Discussion and Analysis of Financial Condition and Results of Operations for additional discussion of the sensitivities surrounding these estimates.

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Proved Reserves

Years Ended December 31	Crude Oil Millions of Barrels									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed and Undeveloped										
Consolidated operations										
End of 2009	1,104	253	1,357	29	469	-	289	267	108	2,519
Revisions	60	14	74	3	26	-	10	2	-	115
Improved recovery	51	2	53	-	-	-	1	-	-	54
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	17	27	44	1	14	-	7	10	-	76
Production	(79)	(30)	(109)	(5)	(72)	-	(44)	(27)	-	(257)
Sales	-	(5)	(5)	(6)	-	-	-	-	-	(11)
End of 2010	1,153	261	1,414	22	437	-	263	252	108	2,496
Revisions	69	18	87	4	(5)	-	(6)	4	-	84
Improved recovery	14	3	17	1	49	-	13	-	-	80
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	21	56	77	2	99	-	8	-	-	186
Production	(73)	(34)	(107)	(4)	(60)	-	(36)	(13)	-	(220)
Sales	-	(8)	(8)	(1)	-	-	-	-	-	(9)
End of 2011	1,184	296	1,480	24	520	-	242	243	108	2,617
Revisions	(2)	11	9	2	28	-	13	2	-	54
Improved recovery	12	4	16	-	-	-	-	-	-	16
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	22	183	205	3	3	-	32	7	-	250
Production	(68)	(47)	(115)	(5)	(49)	-	(25)	(23)	-	(217)
Sales	-	-	-	-	(15)	-	(21)	-	-	(36)
End of 2012	1,148	447	1,595	24	487	-	241	229	108	2,684
Equity affiliates										
End of 2009	-	-	-	-	-	1,586	68	-	-	1,654
Revisions	-	-	-	-	-	6	35	-	-	41
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(114)	(1)	-	-	(115)
Sales	-	-	-	-	-	(1,403)	-	-	-	(1,403)
End of 2010	-	-	-	-	-	75	102	-	-	177
Revisions	-	-	-	-	-	(37)	-	-	-	(37)
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(11)	(5)	-	-	(16)
Sales	-	-	-	-	-	-	-	-	-	-

End of 2011	-	-	-	-	-	27	97	-	-	124
Revisions	-	-	-	-	-	1	-	-	-	1
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	(6)	-	-	(11)
Sales	-	-	-	-	-	(19)	-	-	-	(19)
End of 2012	-	-	-	-	-	4	91	-	-	95
Total company										
End of 2009	1,104	253	1,357	29	469	1,586	357	267	108	4,173
End of 2010	1,153	261	1,414	22	437	75	365	252	108	2,673
End of 2011	1,184	296	1,480	24	520	27	339	243	108	2,741
End of 2012	1,148	447	1,595	24	487	4	332	229	108	2,779

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Years Ended December 31	Crude Oil Millions of Barrels									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed										
Consolidated operations										
End of 2009	1,015	226	1,241	28	287	-	180	246	-	1,982
End of 2010	1,024	223	1,247	21	270	-	181	235	-	1,954
End of 2011	1,056	234	1,290	22	296	-	156	232	-	1,996
End of 2012	1,017	271	1,288	23	267	-	136	217	-	1,931
Equity affiliates										
End of 2009	-	-	-	-	-	1,199	-	-	-	1,199
End of 2010	-	-	-	-	-	73	102	-	-	175
End of 2011	-	-	-	-	-	27	97	-	-	124
End of 2012	-	-	-	-	-	4	91	-	-	95
Undeveloped										
Consolidated operations										
End of 2009	89	27	116	1	182	-	109	21	108	537
End of 2010	129	38	167	1	167	-	82	17	108	542
End of 2011	128	62	190	2	224	-	86	11	108	621
End of 2012	131	176	307	1	220	-	105	12	108	753
Equity affiliates										
End of 2009	-	-	-	-	-	387	68	-	-	455
End of 2010	-	-	-	-	-	2	-	-	-	2
End of 2011	-	-	-	-	-	-	-	-	-	-
End of 2012	-	-	-	-	-	-	-	-	-	-

Notable changes in proved crude oil reserves in the three years ended December 31, 2012, included:

Extensions and discoveries: In 2012, extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford and Bakken. In 2011, extensions and discoveries in Europe were primarily due to the sanctioning of the Ekofisk South and Clair Ridge developments in the North Sea.

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

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Years Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
					Natural Gas Liquids Millions of Barrels					
Developed and Undeveloped										
Consolidated operations										
End of 2009	116	432	548	52	32	-	43	-	-	675
Revisions	21	(6)	15	12	2	-	(3)	19	-	45
Improved recovery	-	-	-	-	-	-	4	-	-	4
Purchases	-	1	1	-	-	-	-	-	-	1
Extensions and discoveries	-	3	3	3	4	-	-	-	-	10
Production	(5)	(25)	(30)	(9)	(6)	-	(7)	(1)	-	(53)
Sales	-	(17)	(17)	-	-	-	-	-	-	(17)
End of 2010	132	388	520	58	32	-	37	18	-	665
Revisions	1	27	28	6	2	-	(1)	1	-	36
Improved recovery	-	-	-	-	2	-	-	-	-	2
Purchases	-	1	1	-	-	-	-	-	-	1
Extensions and discoveries	-	12	12	2	3	-	-	-	-	17
Production	(6)	(26)	(32)	(9)	(4)	-	(5)	(1)	-	(51)
Sales	-	-	-	-	-	-	-	-	-	-
End of 2011	127	402	529	57	35	-	31	18	-	670
Revisions	1	(10)	(9)	1	(2)	-	(3)	-	-	(13)
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	1	1	-	-	-	-	-	-	1
Extensions and discoveries	-	40	40	3	-	-	-	-	-	43
Production	(6)	(30)	(36)	(9)	(2)	-	(6)	(1)	-	(54)
Sales	-	-	-	-	(1)	-	-	-	-	(1)
End of 2012	122	403	525	52	30	-	22	17	-	646
Equity affiliates										
End of 2009	-	-	-	-	-	18	38	-	-	56
Revisions	-	-	-	-	-	-	16	-	-	16
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	(18)	-	-	-	(18)
End of 2010	-	-	-	-	-	-	54	-	-	54
Revisions	-	-	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	(3)	-	-	(3)
Sales	-	-	-	-	-	-	-	-	-	-
End of 2011	-	-	-	-	-	-	51	-	-	51
Revisions	-	-	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-	-

Production	-	-	-	-	-	-	(3)	-	-	(3)
Sales	-	-	-	-	-	-	-	-	-	-
End of 2012	-	-	-	-	-	-	48	-	-	48
Total company										
End of 2009	116	432	548	52	32	18	81	-	-	731
End of 2010	132	388	520	58	32	-	91	18	-	719
End of 2011	127	402	529	57	35	-	82	18	-	721
End of 2012	122	403	525	52	30	-	70	17	-	694

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Years Ended December 31	Natural Gas Liquids Millions of Barrels									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed										
Consolidated operations										
End of 2009	115	332	447	49	25	-	41	-	-	562
End of 2010	131	311	442	54	20	-	37	16	-	569
End of 2011	126	330	456	52	21	-	31	16	-	576
End of 2012	121	335	456	49	17	-	22	15	-	559
Equity affiliates										
End of 2009	-	-	-	-	-	14	-	-	-	14
End of 2010	-	-	-	-	-	-	54	-	-	54
End of 2011	-	-	-	-	-	-	51	-	-	51
End of 2012	-	-	-	-	-	-	48	-	-	48
Undeveloped										
Consolidated operations										
End of 2009	1	100	101	3	7	-	2	-	-	113
End of 2010	1	77	78	4	12	-	-	2	-	96
End of 2011	1	72	73	5	14	-	-	2	-	94
End of 2012	1	68	69	3	13	-	-	2	-	87
Equity affiliates										
End of 2009	-	-	-	-	-	4	38	-	-	42
End of 2010	-	-	-	-	-	-	-	-	-	-
End of 2011	-	-	-	-	-	-	-	-	-	-
End of 2012	-	-	-	-	-	-	-	-	-	-

Notable changes in proved natural gas liquids reserves in the three years ended December 31, 2012, included:

Extensions and discoveries: In 2012, extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford, Barnett and Bakken.

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

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Years Ended December 31	Natural Gas Billions of Cubic Feet									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed and Undeveloped										
Consolidated operations										
End of 2009	2,780	7,962	10,742	2,296	2,009	-	2,912	950	56	18,965
Revisions	155	365	520	309	86	-	(39)	36	-	912
Improved recovery	24	1	25	-	-	-	-	-	-	25
Purchases	-	9	9	-	-	-	-	-	-	9
Extensions and discoveries	4	122	126	84	89	-	24	-	-	323
Production	(101)	(663)	(764)	(358)	(323)	-	(289)	(60)	-	(1,794)
Sales	-	(179)	(179)	(26)	-	-	-	-	-	(205)
End of 2010	2,862	7,617	10,479	2,305	1,861	-	2,608	926	56	18,235
Revisions	186	15	201	134	70	-	(8)	9	-	406
Improved recovery	1	5	6	-	53	-	-	-	-	59
Purchases	-	7	7	1	-	-	-	-	-	8
Extensions and discoveries	3	171	174	78	158	-	192	-	-	602
Production	(92)	(616)	(708)	(338)	(246)	-	(277)	(63)	-	(1,632)
Sales	-	(11)	(11)	(67)	-	-	-	-	-	(78)
End of 2011	2,960	7,188	10,148	2,113	1,896	-	2,515	872	56	17,600
Revisions	(24)	(459)	(483)	(111)	96	-	113	109	2	(274)
Improved recovery	20	7	27	-	-	-	-	-	-	27
Purchases	-	9	9	2	-	-	-	-	-	11
Extensions and discoveries	4	447	451	75	36	-	14	2	-	578
Production	(90)	(595)	(685)	(313)	(208)	-	(263)	(70)	-	(1,539)
Sales	-	-	-	(2)	(14)	-	(31)	-	-	(47)
End of 2012	2,870	6,597	9,467	1,764	1,806	-	2,348	913	58	16,356
Equity affiliates										
End of 2009	-	-	-	-	-	2,705	2,577	-	-	5,282
Revisions	-	-	-	-	-	19	683	-	-	702
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	269	-	-	269
Production	-	-	-	-	-	(91)	(65)	-	-	(156)
Sales	-	-	-	-	-	(2,616)	-	-	-	(2,616)
End of 2010	-	-	-	-	-	17	3,464	-	-	3,481
Revisions	-	-	-	-	-	(11)	(76)	-	-	(87)
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	259	-	-	259
Production	-	-	-	-	-	(2)	(184)	-	-	(186)
Sales	-	-	-	-	-	-	(151)	-	-	(151)
End of 2011	-	-	-	-	-	4	3,312	-	-	3,316
Revisions	-	-	-	-	-	-	(75)	-	-	(75)
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	330	-	-	330

Production	-	-	-	-	-	(1)	(182)	-	-	(183)
Sales	-	-	-	-	-	(3)	(127)	-	-	(130)
End of 2012	-	-	-	-	-	-	3,258	-	-	3,258
Total company										
End of 2009	2,780	7,962	10,742	2,296	2,009	2,705	5,489	950	56	24,247
End of 2010	2,862	7,617	10,479	2,305	1,861	17	6,072	926	56	21,716
End of 2011	2,960	7,188	10,148	2,113	1,896	4	5,827	872	56	20,916
End of 2012	2,870	6,597	9,467	1,764	1,806	-	5,606	913	58	19,614

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Years Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
	Natural Gas Billions of Cubic Feet									
Developed										
Consolidated operations										
End of 2009	2,744	6,633	9,377	2,173	1,772	-	2,537	889	-	16,748
End of 2010	2,785	6,399	9,184	2,134	1,529	-	2,136	865	-	15,848
End of 2011	2,907	6,194	9,101	1,932	1,439	-	1,932	738	-	15,142
End of 2012	2,805	5,737	8,542	1,684	1,290	-	1,696	846	-	14,058
Equity affiliates										
End of 2009	-	-	-	-	-	1,506	307	-	-	1,813
End of 2010	-	-	-	-	-	17	3,114	-	-	3,131
End of 2011	-	-	-	-	-	4	2,943	-	-	2,947
End of 2012	-	-	-	-	-	-	2,723	-	-	2,723
Undeveloped										
Consolidated operations										
End of 2009	36	1,329	1,365	123	237	-	375	61	56	2,217
End of 2010	77	1,218	1,295	171	332	-	472	61	56	2,387
End of 2011	53	994	1,047	181	457	-	583	134	56	2,458
End of 2012	65	860	925	80	516	-	652	67	58	2,298
Equity affiliates										
End of 2009	-	-	-	-	-	1,199	2,270	-	-	3,469
End of 2010	-	-	-	-	-	-	350	-	-	350
End of 2011	-	-	-	-	-	-	369	-	-	369
End of 2012	-	-	-	-	-	-	535	-	-	535

Natural gas production in the reserves table may differ from gas production (delivered for sale) in our statistics disclosure, primarily because the quantities above include gas consumed at the lease.

Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

Notable changes in proved natural gas reserves in the three years ended December 31, 2012, included:

Revisions: In 2012, revisions in Lower 48 were primarily due to lower prices in 2012, versus 2011. In 2012, revisions in Canada were primarily due to lower prices in 2012, versus 2011, as well as improved well performance. In our consolidated operations in Asia Pacific/Middle East, revisions in 2012 were primarily due to development activities in various fields. Revisions in Africa in 2012 were primarily due the execution of a gas sales agreement. In 2010, revisions in Alaska, Lower 48 and Canada were primarily due to higher prices in 2010, versus 2009, as well as improved well performance.

Extensions and discoveries: In 2012, 2011 and 2010, extensions and discoveries in Lower 48 were primarily due to continued drilling success in various fields. In 2012 and 2011, for our equity affiliate operations in Asia Pacific/Middle East, extensions and discoveries were primarily due to APLNG s ongoing development drilling onshore Australia. In 2010, extensions and discoveries in Canada were primarily due to continued drilling success in various fields.

Sales: In 2012, for our equity affiliates in Asia Pacific/Middle East, sales were primarily due to the dilution of our interest in APLNG. In 2010, for our equity affiliates in Russia, sales were primarily due to the disposition of our interest in LUKOIL.

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Years Ended December 31	Other Products Millions of Barrels	
	Synthetic Oil	**Bitumen**
	Canada	Canada
Developed and Undeveloped		
Consolidated operations		
End of 2009	248	417
Revisions	-	42
Improved recovery	-	-
Purchases	-	-
Extensions and discoveries	-	-
Production	(4)	(4)
Sales	(244)	-
End of 2010	-	455
Revisions	-	(1)
Improved recovery	-	-
Purchases	-	-
Extensions and discoveries	-	79
Production	-	(3)
Sales	-	-
End of 2011	-	530
Revisions	-	(20)
Improved recovery	-	-
Purchases	-	-
Extensions and discoveries	-	-
Production	-	(4)
Sales	-	-
End of 2012	-	506
Equity affiliates		
End of 2009	-	716
Revisions	-	13
Improved recovery	-	-
Purchases	-	-
Extensions and discoveries	-	133
Production	-	(18)
Sales	-	-
End of 2010	-	844
Revisions	-	(101)
Improved recovery	-	-
Purchases	-	-
Extensions and discoveries	-	187
Production	-	(21)
Sales	-	-
End of 2011	-	909
Revisions	-	207
Improved recovery	-	-
Purchases	-	-
Extensions and discoveries	-	307
Production	-	(29)
Sales	-	-

End of 2012	-	1,394
Total company		
End of 2009	248	1,133
End of 2010	-	1,299
End of 2011	-	1,439
End of 2012	-	1,900

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Years Ended December 31	Other Products Millions of Barrels	
	Synthetic Oil	**Bitumen**
	Canada	Canada
Developed		
Consolidated operations		
End of 2009	248	24
End of 2010	-	34
End of 2011	-	29
End of 2012	-	25
Equity affiliates		
End of 2009	-	116
End of 2010	-	142
End of 2011	-	131
End of 2012	-	170
Undeveloped		
Consolidated operations		
End of 2009	-	393
End of 2010	-	421
End of 2011	-	501
End of 2012	-	481
Equity affiliates		
End of 2009	-	600
End of 2010	-	702
End of 2011	-	778
End of 2012	-	1,224

Notable changes in proved synthetic oil and bitumen reserves in the three years ended December 31, 2012, included:

Revisions: In 2012, for our bitumen equity operations, revisions were primarily due to well performance and denser well spacing at Foster Creek and Christina Lake. In 2011, for our bitumen equity operations, revisions were primarily due to new subsurface interpretations, as well as the effects of higher prices on sliding scale royalty provisions.

Extensions and discoveries: In 2012, for our bitumen equity operations, extensions and discoveries were primarily related to the sanctioning of Christina Lake Phase F and Narrows Lake Phase A. In 2011, for our consolidated operations, extensions and discoveries were related to continued development of Surmont. In 2011 and 2010, for our equity affiliate operations, extensions and discoveries mainly reflect the continued development of FCCL.

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

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Years Ended December 31	Total Proved Reserves Millions of Barrels of Oil Equivalent									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed and Undeveloped										
Consolidated operations										
End of 2009	1,684	2,012	3,696	1,129	836	-	817	425	117	7,020
Revisions	107	68	175	109	42	-	1	27	-	354
Improved recovery	55	2	57	-	-	-	5	-	-	62
Purchases	-	2	2	-	-	-	-	-	-	2
Extensions and discoveries	17	51	68	18	33	-	11	10	-	140
Production	(101)	(165)	(266)	(82)	(132)	-	(99)	(38)	-	(617)
Sales	-	(52)	(52)	(254)	-	-	-	-	-	(306)
End of 2010	1,762	1,918	3,680	920	779	-	735	424	117	6,655
Revisions	101	48	149	31	8	-	(9)	7	-	186
Improved recovery	14	4	18	1	60	-	13	-	-	92
Purchases	-	2	2	-	-	-	-	-	-	2
Extensions and discoveries	21	97	118	97	128	-	40	-	-	383
Production	(94)	(163)	(257)	(73)	(105)	-	(86)	(25)	-	(546)
Sales	-	(10)	(10)	(12)	-	-	-	-	-	(22)
End of 2011	1,804	1,896	3,700	964	870	-	693	406	117	6,750
Revisions	(5)	(75)	(80)	(36)	42	-	29	20	-	(25)
Improved recovery	16	5	21	-	-	-	-	-	-	21
Purchases	-	3	3	-	-	-	-	-	-	3
Extensions and discoveries	22	297	319	19	10	-	34	7	-	389
Production	(89)	(176)	(265)	(71)	(86)	-	(74)	(35)	-	(531)
Sales	-	-	-	-	(18)	-	(27)	-	-	(45)
End of 2012	1,748	1,950	3,698	876	818	-	655	398	117	6,562
Equity affiliates										
End of 2009	-	-	-	716	-	2,055	535	-	-	3,306
Revisions	-	-	-	13	-	9	165	-	-	187
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	133	-	-	45	-	-	178
Production	-	-	-	(18)	-	(129)	(12)	-	-	(159)
Sales	-	-	-	-	-	(1,857)*	-	-	-	(1,857)
End of 2010	-	-	-	844	-	78	733	-	-	1,655
Revisions	-	-	-	(101)	-	(39)	(12)	-	-	(152)
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	187	-	-	43	-	-	230
Production	-	-	-	(21)	-	(11)	(39)	-	-	(71)
Sales	-	-	-	-	-	-	(25)	-	-	(25)
End of 2011	-	-	-	909	-	28	700	-	-	1,637
Revisions	-	-	-	207	-	1	(13)	-	-	195
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	307	-	-	55	-	-	362

Production	-	-	-	(29)	-	(5)	(39)	-	-	(73)
Sales	-	-	-	-	-	(20)	(21)	-	-	(41)
End of 2012	-	-	-	1,394	-	4	682	-	-	2,080
Total company										
End of 2009	1,684	2,012	3,696	1,845	836	2,055	1,352	425	117	10,326
End of 2010	1,762	1,918	3,680	1,764	779	78	1,468	424	117	8,310
End of 2011	1,804	1,896	3,700	1,873	870	28	1,393	406	117	8,387
End of 2012	1,748	1,950	3,698	2,270	818	4	1,337	398	117	8,642

**Includes 594 million BOE due to the cessation of equity accounting.*

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Years Ended December 31	Total Proved Reserves Millions of Barrels of Oil Equivalent									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed										
Consolidated operations										
End of 2009	1,588	1,663	3,251	711	608	-	644	394	-	5,608
End of 2010	1,619	1,601	3,220	465	545	-	574	396	-	5,200
End of 2011	1,666	1,597	3,263	425	556	-	510	371	-	5,125
End of 2012	1,606	1,562	3,168	377	499	-	441	373	-	4,858
Equity affiliates										
End of 2009	-	-	-	116	-	1,464	51	-	-	1,631
End of 2010	-	-	-	142	-	76	675	-	-	893
End of 2011	-	-	-	131	-	28	638	-	-	797
End of 2012	-	-	-	170	-	4	593	-	-	767
Undeveloped										
Consolidated operations										
End of 2009	96	349	445	418	228	-	173	31	117	1,412
End of 2010	143	317	460	455	234	-	161	28	117	1,455
End of 2011	138	299	437	539	314	-	183	35	117	1,625
End of 2012	142	388	530	499	319	-	214	25	117	1,704
Equity affiliates										
End of 2009	-	-	-	600	-	591	484	-	-	1,675
End of 2010	-	-	-	702	-	2	58	-	-	762
End of 2011	-	-	-	778	-	-	62	-	-	840
End of 2012	-	-	-	1,224	-	-	89	-	-	1,313

Natural gas reserves are converted to BOE based on a 6:1 ratio: six thousand cubic feet of natural gas converts to one BOE.

Proved Undeveloped Reserves

We had 3,017 million BOE of proved undeveloped reserves at year-end 2012, compared with 2,465 million BOE at year-end 2011. We converted 247 million BOE of undeveloped reserves to developed during 2012 as we achieved startup of major development projects. In addition, we added 799 million BOE of undeveloped reserves in 2012 mainly through extensions and discoveries from ongoing development progress and exploration success, as well as through revisions. As a result, at December 31, 2012, our proved undeveloped reserves represented 35 percent of total proved reserves, compared with 29 percent at December 31, 2011. Costs incurred for the year ended December 31, 2012, relating to the development of proved undeveloped reserves were $7.7 billion.

Approximately 70 percent of our proved undeveloped reserves at year-end 2012 were associated with seven major development areas. Five of the major development areas are currently producing and are expected to have proved undeveloped reserves convert to developed over time as development activities continue and/or production facilities are expanded or upgraded, and include:

- FCCL oil sands Foster Creek and Christina Lake in Canada.
- The Surmont oil sands project in Canada.
- The Ekofisk Field in the North Sea.
- The Eagle Ford area in the Lower 48.

The remaining major projects include the Kashagan Field in Kazakhstan and Narrows Lake in our FCCL oil sands in Canada. In November, we announced our intention to sell our interest in Kashagan, and the transaction is expected to close by mid-2013. Narrows Lake was sanctioned for development in 2012.

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At the end of 2012, we did not have any material amounts of proved undeveloped reserves in individual fields or countries that have remained undeveloped for five years or more. However, our largest concentrations of proved undeveloped reserves at year-end 2012 are located in the Athabasca oil sands in Canada, consisting of the FCCL and Surmont steam-assisted gravity drainage (SAGD) projects. The majority of our remaining proved undeveloped reserves in this area were recorded beginning in 2007, and we expect a material portion of these reserves will remain undeveloped for more than five years.

Our SAGD projects are large, multi-year projects with steady, long-term production at consistent levels. The associated reserves are expected to be developed over many years as additional well pairs are drilled across the extensive resource base to maintain throughput at the central processing facilities.

Results of Operations

The Company s results of operations from oil and gas activities for the years 2012, 2011 and 2010 are shown in the following tables. Additional information about selected line items within the results of operations tables is shown below:

Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income.

Taxes other than income taxes include production, property and other non-income taxes.

Depreciation of support equipment is reclassified as applicable.

Transportation costs include costs to transport our produced hydrocarbons to their points of sale, as well as processing fees paid to process natural gas to natural gas liquids. The profit element of transportation operations in which we have an ownership interest is deemed to be outside oil and gas producing activities. The net income of the transportation operations is included in other earnings.

Other related expenses include foreign currency transaction gains and losses and other miscellaneous expenses.

Other earnings include non-oil and gas activities, such as pipeline and marine operations, liquefied natural gas operations, and crude oil and gas marketing activities.

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Results of Operations

Year Ended December 31, 2012	Millions of Dollars										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Disc Ops	Total
Consolidated operations											
Sales	$ 8,306	6,386	14,692	1,722	7,630	-	4,802	1,739	-	1,124	31,709
Transfers	38	309	347	-	-	-	867	-	-	-	1,214
Other revenues	(1)	70	69	107	568	-	930	258	27	1	1,960
Total revenues	8,343	6,765	15,108	1,829	8,198	-	6,599	1,997	27	1,125	34,883
Production costs excluding taxes	1,108	1,460	2,568	788	978	-	754	56	-	240	5,384
Taxes other than income taxes	2,477	513	2,990	65	24	1	321	2	5	21	3,429
Exploration expenses	34	343	377	633	102	1	70	55	210	20	1,468
Depreciation, depletion and amortization	421	2,561	2,982	1,335	958	1	883	44	-	181	6,384
Impairments	-	192	192	162	211	-	4	-	-	606	1,175
Transportation costs	680	368	1,048	113	233	-	113	3	-	22	1,532
Other related expenses	133	136	269	79	(14)	18	107	8	6	58	531
Accretion	55	66	121	57	186	-	21	-	-	8	393
	3,435	1,126	4,561	(1,403)	5,520	(21)	4,326	1,829	(194)	(31)	14,587
Provision for income taxes	1,229	209	1,438	(391)	3,980	6	1,514	1,728	(23)	183	8,435
Results of operations	2,206	917	3,123	(1,012)	1,540	(27)	2,812	101	(171)	(214)	6,152
Other earnings	67	(175)	(108)	(209)	9	8	253	-	76	10	39
Net income (loss) attributable to ConocoPhillips	$ 2,273	742	3,015	(1,221)	1,549	(19)	3,065	101	(95)	(204)	6,191
Equity affiliates											
Sales	$ -	-	-	1,566	-	443	930	-	-	-	2,939
Transfers	-	-	-	-	-	-	1,387	-	-	-	1,387
Other revenues	-	-	-	16	-	206	(117)	-	201	-	306
Total revenues	-	-	-	1,582	-	649	2,200	-	201	-	4,632
Production costs excluding taxes	-	-	-	470	-	45	135	-	-	-	650
Taxes other than income taxes	-	-	-	9	-	293	1,153	-	-	-	1,455
Exploration expenses	-	-	-	36	2	4	1	-	-	-	43
Depreciation, depletion and amortization	-	-	-	325	-	15	109	-	-	-	449
Impairments	-	-	-	-	-	-	-	-	-	-	-
Transportation costs	-	-	-	-	-	74	21	-	-	-	95
Other related expenses	-	-	-	11	-	1	16	-	-	-	28
Accretion	-	-	-	6	-	1	4	-	-	-	11
	-	-	-	725	(2)	216	761	-	201	-	1,901
Provision for income taxes	-	-	-	181	-	(233)	(29)	-	-	-	(81)
Results of operations	-	-	-	544	(2)	449	790	-	201	-	1,982
Other earnings	-	-	-	-	-	1	100	-	-	-	101
Net income (loss) attributable to ConocoPhillips	$ -	-	-	544	(2)	450	890	-	201	-	2,083

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Year Ended December 31, 2011	Millions of Dollars										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East*	Africa	Other Areas	Disc Ops	Total
Consolidated operations											
Sales**	$ 8,143	6,396	14,539	2,299	9,087	-	6,024	185	-	1,355	33,489
Transfers**	45	400	445	-	-	-	809	-	-	-	1,254
Other revenues	(46)	303	257	138	(16)	-	15	21	16	9	440
Total revenues	8,142	7,099	15,241	2,437	9,071	-	6,848	206	16	1,364	35,183
Production costs excluding taxes	1,023	1,286	2,309	781	956	-	742	41	-	225	5,054
Taxes other than income taxes	2,721	520	3,241	65	4	1	543	2	-	21	3,877
Exploration expenses	36	368	404	177	201	-	192	36	40	29	1,079
Depreciation, depletion and amortization	468	2,113	2,581	1,504	1,407	1	940	8	-	180	6,621
Impairments	2	71	73	253	(38)	-	-	-	-	-	288
Transportation costs	609	432	1,041	128	273	-	120	4	-	23	1,589
Other related expenses	48	105	153	59	43	26	74	-	7	54	416
Accretion	59	58	117	50	203	-	23	-	-	3	396
	3,176	2,146	5,322	(580)	6,022	(28)	4,214	115	(31)	829	15,863
Provision for income taxes	1,167	755	1,922	(194)	4,355	3	1,844	160	(6)	545	8,629
Results of operations	2,009	1,391	3,400	(386)	1,667	(31)	2,370	(45)	(25)	284	7,234
Other earnings	(46)	(217)	(263)	(37)	189	16	201	14	101	(17)	204
Net income (loss) attributable to ConocoPhillips	$ 1,963	1,174	3,137	(423)	1,856	(15)	2,571	(31)	76	267	7,438
Equity affiliates											
Sales	$ -	-	-	1,295	-	1,107	956	-	-	-	3,358
Transfers	-	-	-	-	-	-	900	-	-	-	900
Other revenues	-	-	-	6	-	-	(273)	-	-	-	(267)
Total revenues	-	-	-	1,301	-	1,107	1,583	-	-	-	3,991
Production costs excluding taxes	-	-	-	367	-	72	108	-	-	-	547
Taxes other than income taxes	-	-	-	5	-	750	881	-	-	-	1,636
Exploration expenses	-	-	-	36	-	1	2	-	-	-	39
Depreciation, depletion and amortization	-	-	-	209	-	52	112	-	-	-	373
Impairments	-	-	-	-	-	395	-	-	-	-	395
Transportation costs	-	-	-	-	-	139	15	-	-	-	154
Other related expenses	-	-	-	3	-	-	(4)	-	-	-	(1)
Accretion	-	-	-	4	-	1	3	-	-	-	8
	-	-	-	677	-	(303)	466	-	-	-	840
Provision for income taxes	-	-	-	159	-	18	32	-	-	-	209
Results of operations	-	-	-	518	-	(321)	434	-	-	-	631
Other earnings	-	-	-	-	-	238	99	-	-	-	337
	$ -	-	-	518	-	(83)	533	-	-	-	968

Net income (loss)
attributable to
ConocoPhillips

* *Certain amounts have been restated to reflect revised natural gas prices, reclassify amounts previously considered non-oil and gas producing activities and reclassify amounts between consolidated and equity affiliates .*

** *Commodity sales to Phillips 66, reported as transfers prior to the separation, are now reported as third-party sales.*

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Year Ended					Millions of Dollars						
December 31, 2010	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Disc Ops	Total
Consolidated operations											
Sales*	$ 6,270	5,685	11,955	2,625	8,245	-	5,090	1,286	-	907	30,108
Transfers*	68	304	372	-	-	-	638	-	-	-	1,010
Other revenues	-	559	559	3,216	142	-	55	167	18	5	4,162
Total revenues	6,338	6,548	12,886	5,841	8,387	-	5,783	1,453	18	912	35,280
Production costs excluding taxes	849	1,230	2,079	873	1,004	-	538	57	-	239	4,790
Taxes other than income taxes	1,570	498	2,068	74	6	1	355	3	1	15	2,523
Exploration expenses	37	292	329	295	146	2	260	19	81	30	1,162
Depreciation, depletion and amortization	529	2,231	2,760	1,666	1,972	2	1,206	44	-	158	7,808
Impairments	4	19	23	13	43	-	-	-	-	-	79
Transportation costs	528	424	952	134	281	-	119	4	-	19	1,509
Other related expenses	(38)	138	100	31	3	21	(60)	27	3	48	173
Accretion	58	55	113	50	192	-	24	-	-	4	383
	2,801	1,661	4,462	2,705	4,740	(26)	3,341	1,299	(67)	399	16,853
Provision for income taxes	1,014	555	1,569	108	3,066	(23)	1,361	1,177	(10)	263	7,511
Results of operations	1,787	1,106	2,893	2,597	1,674	(3)	1,980	122	(57)	136	9,342
Other earnings	(75)	(136)	(211)	(56)	51	31	215	(9)	89	8	118
Net income (loss) attributable to ConocoPhillips	$ 1,712	970	2,682	2,541	1,725	28	2,195	113	32	144	9,460
Equity affiliates											
Sales	$ -	-	-	955	-	5,189	249	-	-	-	6,393
Transfers	-	-	-	-	-	1,876	-	-	-	-	1,876
Other revenues	-	-	-	7	-	1,219	10	-	-	-	1,236
Total revenues	-	-	-	962	-	8,284	259	-	-	-	9,505
Production costs excluding taxes	-	-	-	265	-	544	59	-	-	-	868
Taxes other than income taxes	-	-	-	4	-	3,463	42	-	-	-	3,509
Exploration expenses	-	-	-	-	-	61	(2)	-	-	-	59
Depreciation, depletion and amortization	-	-	-	190	-	568	55	-	-	-	813
Impairments	-	-	-	-	-	645	-	-	-	-	645
Transportation costs	-	-	-	-	-	784	25	-	-	-	809
Other related expenses	-	-	-	(3)	-	-	44	-	-	-	41
Accretion	-	-	-	2	-	7	2	-	-	-	11
	-	-	-	504	-	2,212	34	-	-	-	2,750
Provision for income taxes	-	-	-	128	-	647	(25)	-	-	-	750
Results of operations	-	-	-	376	-	1,565	59	-	-	-	2,000
Other earnings	-	-	-	-	-	405	(86)	-	-	-	319
Net income (loss) attributable to ConocoPhillips	$ -	-	-	376	-	1,970	(27)	-	-	-	2,319

* *Commodity sales to Phillips 66, reported as transfers prior to the separation, are now reported as third-party sales.*

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Statistics

Net Production	**2012**	2011	2010
	Thousands of Barrels Daily		
Crude Oil			
Consolidated operations			
Alaska	**188**	200	215
Lower 48	**123**	94	85
United States	**311**	294	300
Canada	**13**	12	15
Europe	**135**	164	196
Asia Pacific/Middle East	**68**	99	122
Africa	**40**	8	46
Total consolidated operations	**567**	577	679
Equity affiliates			
Russia	**13**	29	336
Asia Pacific/Middle East	**15**	16	2
Total equity affiliates	**28**	45	338
Total continuing operations	**595**	622	1,017
Discontinued operations	**23**	28	30
Total company	**618**	650	1,047
Natural Gas Liquids			
Consolidated operations			
Alaska	**16**	15	15
Lower 48	**85**	74	75
United States	**101**	89	90
Canada	**24**	26	23
Europe	**7**	11	15
Asia Pacific/Middle East	**16**	12	18
Total consolidated operations	**148**	138	146
Equity affiliates Asia Pacific/Middle East	**8**	7	1
Total continuing operations	**156**	145	147
Discontinued operations	**4**	4	3
Total company	**160**	149	150
Synthetic Oil			
Consolidated operations Canada	**-**	-	12

Bitumen			
Consolidated operations Canada	**12**	10	10
Equity affiliates Canada	**81**	57	49
Total company	**93**	67	59
Natural Gas	Millions of Cubic Feet Daily		
Consolidated operations			
Alaska	**55**	61	82
Lower 48	**1,493**	1,556	1,695
United States	**1,548**	1,617	1,777
Canada	**857**	928	984
Europe	**516**	626	815
Asia Pacific/Middle East	**672**	695	712
Africa	**18**	1	8
Total consolidated operations	**3,611**	3,867	4,296
Equity affiliates			
Russia	-	-	254
Asia Pacific/Middle East	**485**	492	169
Total equity affiliates	**485**	492	423
Total continuing operations	**4,096**	4,359	4,719
Discontinued operations	**149**	157	141
Total company	**4,245**	4,516	4,860

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Average Sales Prices		**2012**	2011	2010
Crude Oil Per Barrel				
Consolidated operations				
Alaska	$	**109.62**	105.95	78.65
Lower 48		**91.67**	92.79	73.52
United States		**102.90**	101.89	77.19
Canada		**78.26**	86.04	67.99
Europe		**113.08**	111.82	79.74
Asia Pacific/Middle East		**108.20**	109.84	77.69
Africa		**110.75**	98.30	79.22
Total international		**109.64**	109.76	78.57
Total consolidated operations		**105.86**	105.68	77.96
Equity affiliates				
Russia		**96.50**	101.62	56.65
Asia Pacific/Middle East		**108.07**	106.96	89.24
Total equity affiliates		**102.80**	103.42	56.86
Total continuing operations		**105.72**	105.52	70.94
Discontinued operations		**112.90**	113.43	80.15
Natural Gas Liquids Per Barrel				
Consolidated operations				
Lower 48	$	**35.45**	50.55	39.92
United States		**35.45**	50.55	39.92
Canada		**48.64**	56.84	47.68
Europe		**61.53**	59.19	46.75
Asia Pacific/Middle East		**79.26**	72.87	60.57
Total international		**61.01**	61.27	51.43
Total consolidated operations		**44.62**	54.79	45.91
Equity affiliates Asia Pacific/Middle East		**77.30**	70.62	65.16
Total continuing operations		**46.36**	55.73	46.00
Discontinued operations		**13.30**	13.63	11.26
Synthetic Oil Per Barrel				
Consolidated operations Canada	$	**-**	-	77.56
Bitumen Per Barrel				
Consolidated operations Canada	$	**57.58**	55.16	51.10
Equity affiliates Canada		**53.39**	63.93	53.43
Natural Gas Per Thousand Cubic Feet				
Consolidated operations				
Alaska	$	**4.22**	4.56	4.62
Lower 48		**2.67**	3.99	4.25
United States		**2.72**	4.01	4.27
Canada		**2.13**	3.46	3.74
Europe		**9.76**	9.26	6.94
Asia Pacific/Middle East		**10.63**	9.82	7.39
Africa		**5.55**	0.09	0.09
Total international		**6.84**	7.04	5.80
Total consolidated operations		**5.07**	5.78	5.17
Equity affiliates				
Russia		**-**	-	1.18
Asia Pacific/Middle East*		**8.54**	5.93	1.91
Total equity affiliates		**8.54**	5.93	1.47
Total continuing operations		**5.48**	5.80	4.84
Discontinued operations		**2.57**	2.25	1.86

* *Prior periods have been restated to reflect revised equity affiliates natural gas prices.*

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		2012	2011	2010
Average Production Costs Per Barrel of Oil Equivalent*				
Consolidated operations				
Alaska	$	**14.20**	12.45	9.55
Lower 48		**8.73**	8.24	7.62
United States		**10.47**	9.70	8.30
Canada		**11.22**	10.56	10.68
Europe		**11.72**	9.38	7.93
Asia Pacific/Middle East		**10.46**	8.96	5.70
Africa		**3.56**	13.75	3.30
Total international		**10.67**	9.63	7.72
Total consolidated continuing operations		**10.57**	9.66	7.98
Equity affiliates				
Canada		**15.85**	17.64	14.82
Russia		**9.48**	6.80	3.94
Asia Pacific/Middle East		**3.59**	2.82	5.19
Total equity affiliates		**9.02**	7.85	5.19
Discontinued operations		**12.90**	10.60	11.59
Average Production Costs Per Barrel Bitumen				
Consolidated operations Canada	$	**27.09**	27.12	19.45
Equity affiliates Canada		**15.85**	17.64	14.82
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**31.75**	33.11	17.65
Lower 48		**3.07**	3.33	3.08
United States		**12.19**	13.61	8.26
Canada		**0.93**	0.88	0.91
Europe		**0.29**	0.04	0.05
Asia Pacific/Middle East		**4.45**	6.56	3.76
Africa		**0.13**	0.67	0.17
Total international		**1.73**	2.35	1.37
Total consolidated continuing operations		**7.00**	7.71	4.40
Equity affiliates				
Canada		**0.30**	0.24	0.22
Russia		**61.75**	70.85	25.08
Asia Pacific/Middle East**		**30.63**	22.99	3.69
Total equity affiliates		**20.20**	23.47	20.97
Discontinued operations		**1.13**	0.99	0.73
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**5.40**	5.69	5.95
Lower 48		**15.32**	13.55	13.81
United States		**12.16**	10.84	11.02
Canada		**19.01**	20.33	20.38
Europe		**11.47**	13.80	15.58
Asia Pacific/Middle East		**12.25**	11.35	12.77
Africa		**2.80**	2.68	2.55
Total international		**13.33**	14.75	15.28
Total consolidated continuing operations		**12.74**	12.89	13.41
Equity affiliates				
Canada		**10.96**	10.05	10.62
Russia		**3.16**	4.91	4.11
Asia Pacific/Middle East**		**2.90**	2.92	4.83
Total equity affiliates		**6.23**	5.35	4.86
Discontinued operations		**9.73**	8.48	7.66

* *Includes bitumen.*

** *Certain amounts have been restated to reflect revised Results of Operations.*

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Development and Exploration Activities

The following two tables summarize our net interest in productive and dry exploratory and development wells in the years ended December 31, 2012, 2011 and 2010. A development well is a well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive. An exploratory well is a well drilled to find and produce crude oil or natural gas in an unknown field or a new reservoir within a proven field. Excluded from the exploratory well count are stratigraphic-type exploratory wells, primarily relating to oil sands delineation wells located in Canada and coalbed methane test wells located in Asia Pacific/Middle East.

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Net Wells Completed[1]

	Productive			Dry		
	2012	2011	2010	**2012**	2011	2010
Exploratory[2][3]						
Consolidated operations						
Alaska	*	-	-	-	-	-
Lower 48	**92**	98	23	**2**	5	1
United States	**92**	98	23	**2**	5	1
Canada	**5**	8	15	**-**	3	7
Europe	*	1	1	*	*	*
Asia Pacific/Middle East	*	1	3	**-**	1	1
Africa	*	*	1	**-**	*	*
Other areas	*	-	-	*	-	-
Total consolidated operations	**97**	108	43	**2**	9	9
Equity affiliates						
Russia	**-**	-	-	*	-	-
Asia Pacific/Middle East	**-**	*	-	**-**	-	-
Total equity affiliates	**-**	-	-	**-**	-	-
Includes extension wells of:	*82*	*98*	*23*	*-*	*3*	*1*

	Productive			Dry		
	2012	2011	2010	**2012**	2011	2010
Development						
Consolidated operations						
Alaska	**21**	26	28	**-**	-	*
Lower 48	**377**	350	269	*	4	2
United States	**398**	376	297	**-**	4	2
Canada	**119**	146	186	**3**	1	12
Europe	**4**	4	6	**-**	-	-
Asia Pacific/Middle East	**11**	30	59	**-**	-	*
Africa	**4**	5	9	**-**	-	-
Total consolidated operations	**536**	561	557	**3**	5	14
Equity affiliates						
Canada	**30**	20	35	**-**	-	-
Russia	**1**	3	2	**-**	-	-
Asia Pacific/Middle East	**13**	9	25	**-**	1	-
Total equity affiliates	**44**	32	62	**-**	1	-

(1) Restated to conform to current year presentation.
(2) Excludes net stratigraphic-type exploratory wells of 213, 210 and 191 for the years ended December 31, 2012, 2011 and 2010, respectively.
(3) Includes wells drilled in areas near or offsetting current production, or in areas where well density or production history have not achieved statistical certainty of results, primarily located in the Lower 48.
** Our total proportionate interest was less than one.*

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The table below represents the status of our wells drilling at December 31, 2012, and includes wells in the process of drilling or in active completion.

Wells at December 31, 2012			Productive*			
	In Progress		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
Consolidated operations						
Alaska	6	3	1,741	769	37	22
Lower 48	327	191	9,613	4,563	24,833	15,523
United States	333	194	11,354	5,332	24,870	15,545
Canada	82	46	1,647	967	12,731	7,462
Europe	19	5	485	89	275	113
Asia Pacific/Middle East	34	15	353	155	112	52
Africa	52	8	1,169	205	62	12
Other areas	35	3	-	-	-	-
Total consolidated operations	555	271	15,008	6,748	38,050	23,184
Equity affiliates						
Canada	9	5	282	141	-	-
Russia	-	-	29	14	-	-
Asia Pacific/Middle East	770	153	-	-	617	137
Total equity affiliates	779	158	311	155	617	137

* *Includes 415 gross and 204 net multiple completion wells.*

Acreage at December 31, 2012	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Consolidated operations				
Alaska	655	332	1,403	1,204
Lower 48	7,091	5,165	11,362	9,683
United States	7,746	5,497	12,765	10,887
Canada	6,615	4,313	6,327	4,379
Europe	824	243	2,045	831
Asia Pacific/Middle East	4,096	1,771	27,463	17,753
Africa	528	132	17,254	3,474
Other areas	-	-	9,225	3,607
Total consolidated operations	19,809	11,956	75,079	40,931
Equity affiliates				
Canada	38	15	653	278
Europe	-	-	506	355
Russia	16	8	619	309

Asia Pacific/Middle East	1,129	222	7,681	2,348
Total equity affiliates	1,183	245	9,459	3,290

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Costs Incurred

Year Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
	Millions of Dollars									
2012										
Consolidated operations										
Unproved property acquisition	$ 2	562	564	14	2	-	-	333	-	913
Proved property acquisition	-	33	33	3	-	-	-	-	-	36
	2	595	597	17	2	-	-	333	-	949
Exploration	104	1,272	1,376	218	91	1	248	94	141	2,169
Development	644	3,917	4,561	2,062	3,515	-	1,113	208	585	12,044
	$ 750	5,784	6,534	2,297	3,608	1	1,361	635	726	15,162
Equity affiliates										
Unproved property acquisition	$ -	-	-	12	-	-	-	-	-	12
Proved property acquisition	-	-	-	-	-	-	-	-	-	-
	-	-	-	12	-	-	-	-	-	12
Exploration	-	-	-	77	11	-	52	-	-	140
Development	-	-	-	1,332	-	13	1,163	-	-	2,508
	$ -	-	-	1,421	11	13	1,215	-	-	2,660
2011										
Consolidated operations										
Unproved property acquisition	$ 1	577	578	145	-	-	-	-	-	723
Proved property acquisition	-	10	10	-	-	-	36	-	-	46
	1	587	588	145	-	-	36	-	-	769
Exploration*	84	1,330	1,414	269	201	1	226	63	88	2,262
Development*	499	2,334	2,833	1,347	2,123	-	949	263	726	8,241
	$ 584	4,251	4,835	1,761	2,324	1	1,211	326	814	11,272
Equity affiliates										
Unproved property	$ -	-	-	-	-	-	484	-	-	484
Proved property acquisition	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	484	-	-	484
Exploration	-	-	-	64	-	1	100	-	-	165
Development**	-	-	-	911	-	43	478	-	-	1,432
	$ -	-	-	975	-	44	1,062	-	-	2,081

* *Amounts in Lower 48 were reclassified between Exploration and Development. Total costs were unchanged.*
** *Asia Pacific/Middle East equity affiliates Development costs were restated to reflect amounts considered to be non-oil and gas producing activities.*

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Year Ended December 31	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
2010										
Consolidated operations										
Unproved property acquisition	$ (26)	286	260	113	9	-	-	-	-	382
Proved property acquisition	-	100	100	1	-	-	-	-	-	101
	(26)	386	360	114	9	-	-	-	-	483
Exploration	119	487	606	269	144	3	356	45	143	1,566
Development	588	1,439	2,027	927	1,351	-	858	375	729	6,267
	$ 681	2,312	2,993	1,310	1,504	3	1,214	420	872	8,316
Equity affiliates										
Unproved property acquisition	$ -	-	-	81	-	15	379	-	-	475
Proved property acquisition	-	-	-	-	-	173	-	-	-	173
	-	-	-	81	-	188	379	-	-	648
Exploration	-	-	-	-	-	92	123	-	-	215
Development	-	-	-	621	-	751	403	-	-	1,775
	$ -	-	-	702	-	1,031	905	-	-	2,638

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Capitalized Costs

At December 31	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
2012										
Consolidated operations										
Proved property	$ 13,470	40,019	53,489	22,069	25,426	8	12,248	4,060	5,233	122,533
Unproved property	1,543	2,840	4,383	2,071	284	-	1,022	511	220	8,491
	15,013	42,859	57,872	24,140	25,710	8	13,270	4,571	5,453	131,024
Accumulated depreciation, depletion and amortization	6,676	18,186	24,862	12,807	14,317	7	5,460	1,787	669	59,909
	$ 8,337	24,673	33,010	11,333	11,393	1	7,810	2,784	4,784	71,115
Equity affiliates										
Proved property	$ -	-	-	7,498	-	212	4,067	-	-	11,777
Unproved property	-	-	-	1,450	53	-	6,212	-	-	7,715
	-	-	-	8,948	53	212	10,279	-	-	19,492
Accumulated depreciation, depletion and amortization	-	-	-	1,046	-	183	277	-	-	1,506
	$ -	-	-	7,902	53	29	10,002	-	-	17,986
2011										
Consolidated operations										
Proved property	$ 12,770	34,939	47,709	19,578	22,948	8	12,284	3,867	4,650	111,044
Unproved property	1,528	2,574	4,102	1,986	289	1	1,026	174	268	7,846
	14,298	37,513	51,811	21,564	23,237	9	13,310	4,041	4,918	118,890
Accumulated depreciation, depletion and amortization	6,237	15,464	21,701	10,599	14,451	7	5,626	1,559	12	53,955
	$ 8,061	22,049	30,110	10,965	8,786	2	7,684	2,482	4,906	64,935
Equity affiliates										
Proved property*	$ -	-	-	5,774	-	1,966	2,720	-	-	10,460
Unproved property*	-	-	-	1,657	-	146	7,223	-	-	9,026
	-	-	-	7,431	-	2,112	9,943	-	-	19,486
Accumulated depreciation, depletion and amortization	-	-	-	764	-	1,902	184	-	-	2,850
	$ -	-	-	6,667	-	210	9,759	-	-	16,636

* *Asia Pacific/Middle East equity affiliates Proved property was restated to reflect amounts considered to be non-oil and gas producing activities and to reclassify certain costs between Proved property and Unproved property.*

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

In accordance with SEC and FASB requirements, amounts were computed using 12-month average prices and end-of-year costs (adjusted only for existing contractual changes), appropriate statutory tax rates and a prescribed 10 percent discount factor. Twelve-month average prices are calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. For all years, continuation of year-end economic conditions was assumed. The calculations were based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, were not considered. The calculations also require assumptions as to the timing of future production of proved reserves, and the timing and amount of future development costs, including dismantlement, and future production costs, including taxes other than income taxes.

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production.

Discounted Future Net Cash Flows

	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
2012										
Consolidated operations										
Future cash inflows	$ 141,668	71,556	213,224	36,612	73,379	-	49,234	32,009	12,012	416,470
Less:										
Future production and transportation costs	82,663	28,447	111,110	20,995	16,180	-	15,202	4,342	3,653	171,482
Future development costs	12,683	10,604	23,287	12,564	15,273	-	3,851	944	1,158	57,077
Future income tax provisions	16,370	10,840	27,210	1,078	28,187	-	10,424	22,595	1,331	90,825
Future net cash flows	29,952	21,665	51,617	1,975	13,739	-	19,757	4,128	5,870	97,086
10 percent annual discount	16,511	9,461	25,972	1,170	4,936	-	6,393	1,442	3,711	43,624
Discounted future net cash flows	$ 13,441	12,204	25,645	805	8,803	-	13,364	2,686	2,159	53,462
Equity affiliates										
Future cash inflows	$ -	-	-	72,587	-	323	47,394	-	-	120,304
Less:										
Future production and transportation costs	-	-	-	23,967	-	245	23,689	-	-	47,901
Future development costs	-	-	-	9,291	-	10	1,221	-	-	10,522
Future income tax provisions	-	-	-	10,055	-	3	4,335	-	-	14,393
Future net cash flows	-	-	-	29,274	-	65	18,149	-	-	47,488
10 percent annual discount	-	-	-	18,352	-	9	8,677	-	-	27,038
Discounted future net cash flows	$ -	-	-	10,922	-	56	9,472	-	-	20,450
Total company										
Discounted future net cash flows	$ 13,441	12,204	25,645	11,727	8,803	56	22,836	2,686	2,159	73,912

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	Millions of Dollars									
	Alaska*	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East**	Africa	Other Areas	Total
2011										
Consolidated operations										
Future cash inflows	$ 143,652	73,807	217,459	40,581	78,250	-	49,936	33,017	11,891	431,134
Less:										
Future production and transportation costs	82,773	32,766	115,539	19,148	17,166	-	14,380	4,113	3,768	174,114
Future development costs	11,385	7,519	18,904	13,393	16,986	-	3,051	885	2,080	55,299
Future income tax provisions	16,845	11,771	28,616	2,060	29,853	-	11,967	23,825	990	97,311
Future net cash flows	32,649	21,751	54,400	5,980	14,245	-	20,538	4,194	5,053	104,410
10 percent annual discount	18,074	9,643	27,717	4,025	5,372	-	6,649	1,522	3,712	48,997
Discounted future net cash flows	$ 14,575	12,108	26,683	1,955	8,873	-	13,889	2,672	1,341	55,413
Equity affiliates										
Future cash inflows	$ -	-	-	53,618	-	2,786	35,439	-	-	91,843
Less:										
Future production and transportation costs	-	-	-	16,405	-	2,765	16,814	-	-	35,984
Future development costs	-	-	-	7,163	-	36	905	-	-	8,104
Future income tax provisions	-	-	-	7,574	-	3	3,705	-	-	11,282
Future net cash flows	-	-	-	22,476	-	(18)	14,015	-	-	36,473
10 percent annual discount	-	-	-	14,662	-	(39)	7,217	-	-	21,840
Discounted future net cash flows	$ -	-	-	7,814	-	21	6,798	-	-	14,633
Total company										
Discounted future net cash flows	$ 14,575	12,108	26,683	9,769	8,873	21	20,687	2,672	1,341	70,046

* *Restated to reflect revised production and income tax amounts.*

** *Equity affiliates were restated to reclassify amounts between Future cash inflows and Future production and transportation costs. Discounted future net cash flows remains unchanged.*

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	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East*	Africa	Other Areas	Total
2010										
Consolidated operations										
Future cash inflows	$ 102,743	68,949	171,692	38,083	49,270	-	37,673	24,487	8,466	329,671
Less:										
Future production and transportation costs	57,899	29,749	87,648	16,753	12,899	-	10,480	4,142	3,007	134,929
Future development costs	8,792	7,752	16,544	11,161	10,295	-	2,226	1,133	3,050	44,409
Future income tax provisions	13,383	10,953	24,336	2,416	16,765	-	9,211	16,217	384	69,329
Future net cash flows	22,669	20,495	43,164	7,753	9,311	-	15,756	2,995	2,025	81,004
10 percent annual discount	10,723	10,046	20,769	3,890	2,597	-	4,889	1,025	2,368	35,538
Discounted future net cash flows	$ 11,946	10,449	22,395	3,863	6,714	-	10,867	1,970	(343)	45,466
Equity affiliates										
Future cash inflows	$ -	-	-	47,169	-	5,610	24,225	-	-	77,004
Less:										
Future production and transportation costs	-	-	-	16,492	-	4,809	12,416	-	-	33,717
Future development costs	-	-	-	4,684	-	85	295	-	-	5,064
Future income tax provisions	-	-	-	6,649	-	(80)	2,082	-	-	8,651
Future net cash flows	-	-	-	19,344	-	796	9,432	-	-	29,572
10 percent annual discount	-	-	-	13,453	-	293	4,732	-	-	18,478
Discounted future net cash flows	$ -	-	-	5,891	-	503	4,700	-	-	11,094
Total company										
Discounted future net cash flows	$ 11,946	10,449	22,395	9,754	6,714	503	15,567	1,970	(343)	56,560

* *Equity affiliates were restated to reclassify amounts between Future cash inflows and Future production and transportation costs. Discounted future net cash flows remains unchanged.*

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Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars								
	Consolidated Operations			Equity Affiliates			Total Company		
	2012	2011*	2010	**2012**	2011**	2010	**2012**	2011	2010
Discounted future net cash flows at the beginning of the year	**$ 55,413**	45,466	30,393	**14,633**	11,094	11,881	**70,046**	56,560	42,274
Changes during the year									
Revenues less production and transportation costs for the year	**(22,578)**	(24,223)	(22,296)	**(2,126)**	(1,921)	(3,083)	**(24,704)**	(26,144)	(25,379)
Net change in prices and production and transportation costs	**(5,684)**	33,878	39,532	**912**	4,644	3,478	**(4,772)**	38,522	43,010
Extensions, discoveries and improved recovery, less estimated future costs	**11,192**	8,555	4,517	**1,963**	832	297	**13,155**	9,387	4,814
Development costs for the year	**10,944**	8,428	5,617	**2,438**	1,488	1,758	**13,382**	9,916	7,375
Changes in estimated future development costs	**(9,832)**	(8,374)	(2,917)	**(1,731)**	(1,508)	(129)	**(11,563)**	(9,882)	(3,046)
Purchases of reserves in place, less estimated future costs	**16**	19	19	**-**	-	-	**16**	19	19
Sales of reserves in place, less estimated future costs	**(913)**	(390)	(3,729)	**(139)**	(234)	(5,405)	**(1,052)**	(624)	(9,134)
Revisions of previous quantity estimates	**2,047**	(1,606)	3,062	**3,952**	491	372	**5,999**	(1,115)	3,434
Accretion of discount	**10,072**	7,710	5,000	**1,788**	1,284	1,404	**11,860**	8,994	6,404
Net change in income taxes	**2,785**	(14,050)	(13,732)	**(1,240)**	(1,537)	521	**1,545**	(15,587)	(13,211)
Total changes	**(1,951)**	9,947	15,073	**5,817**	3,539	(787)	**3,866**	13,486	14,286
Discounted future net cash flows at year end	**$ 53,462**	55,413	45,466	**20,450**	14,633	11,094	**73,912**	70,046	56,560

* *Restated to reflect revised production and income tax amounts.*

** *Certain amounts in Asia Pacific/Middle East equity affiliates have been restated to reflect revised natural gas prices and to reclassify amounts previously considered non-oil and gas producing activities.*

The net change in prices and production and transportation costs is the beginning-of-year reserve-production forecast multiplied by the net annual change in the per-unit sales price and production and transportation cost, discounted at 10 percent.

Purchases and sales of reserves in place, along with extensions, discoveries and improved recovery, are calculated using production forecasts of the applicable reserve quantities for the year multiplied by the 12-month average sales prices, less future estimated costs, discounted at 10 percent.

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*	Net Income	Net Income Attributable to ConocoPhillips	Net Income Attributable to ConocoPhillips Basic	Diluted
2012						
First	**$ 14,593**	**4,265**	**2,955**	**2,937**	**2.29**	**2.27**
Second	**13,664**	**3,945**	**2,289**	**2,267**	**1.82**	**1.80**
Third	**14,141**	**3,591**	**1,813**	**1,798**	**1.47**	**1.46**
Fourth	**15,569**	**3,622**	**1,441**	**1,426**	**1.16**	**1.16**
2011						
First	$ 15,398	4,551	3,042	3,028	2.11	2.09
Second	16,735	4,256	3,419	3,402	2.43	2.41
Third	16,108	3,401	2,631	2,616	1.93	1.91
Fourth	15,955	3,188	3,410	3,390	2.58	2.56

**Prior periods have been restated as a result of discontinued operations.*

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 100 percent owned by ConocoPhillips. ConocoPhillips Australia Funding Company, ConocoPhillips Canada Funding Company I and ConocoPhillips Canada Funding Company II are indirect, 100 percent owned subsidiaries of ConocoPhillips Company. ConocoPhillips and ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Australia Funding Company, ConocoPhillips Canada Funding Company I, and ConocoPhillips Canada Funding Company II, with respect to their publicly held debt securities. Similarly, ConocoPhillips has fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. In addition, ConocoPhillips Company has fully and unconditionally guaranteed the payment obligations of ConocoPhillips with respect to its publicly held debt securities. All guarantees are joint and several. The following condensed consolidating financial information presents the results of operations, financial position and cash flows for:

- ConocoPhillips, ConocoPhillips Company, ConocoPhillips Australia Funding Company, ConocoPhillips Canada Funding Company I, and ConocoPhillips Canada Funding Company II (in each case, reflecting investments in subsidiaries utilizing the equity method of accounting).
- All other nonguarantor subsidiaries of ConocoPhillips.
- The consolidating adjustments necessary to present ConocoPhillips results on a consolidated basis.

In February 2009, we filed a universal shelf registration statement with the SEC under which ConocoPhillips, as a well-known seasoned issuer, has the ability to issue and sell an indeterminate amount of various types of debt and equity securities, with certain debt securities guaranteed by ConocoPhillips Company. Also as part of that registration statement, ConocoPhillips Trust I and ConocoPhillips Trust II have the ability to issue and sell preferred trust securities, guaranteed by ConocoPhillips. ConocoPhillips Trust I and ConocoPhillips Trust II have not issued any trust-preferred securities under this registration statement, and thus have no assets or liabilities. Accordingly, columns for these two trusts are not included in the condensed consolidating financial information.

This condensed consolidating financial information should be read in conjunction with the accompanying consolidated financial statements and notes.

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Millions of Dollars

Year Ended December 31, 2012

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	$ -	17,768	-	-	-	40,199	-	57,967
Equity in earnings of affiliates	8,858	10,126	-	-	-	1,890	(18,963)	1,911
Gain on dispositions	-	2	-	-	-	1,655	-	1,657
Other income (loss)	(76)	177	-	-	-	368	-	469
Intercompany revenues	61	1,013	46	90	34	4,526	(5,770)	-
Total Revenues and Other Income	8,843	29,086	46	90	34	48,638	(24,733)	62,004
Costs and Expenses								
Purchased commodities	-	15,680	-	-	-	13,000	(3,448)	25,232
Production and operating expenses	-	1,304	-	-	-	5,512	(23)	6,793
Selling, general and administrative expenses	12	845	-	-	-	259	(10)	1,106
Exploration expenses	-	402	-	-	-	1,098	-	1,500
Depreciation, depletion and amortization	-	807	-	-	-	5,773	-	6,580
Impairments	-	8	-	-	-	672	-	680
Taxes other than income taxes	-	264	-	-	-	3,282	-	3,546
Accretion on discounted liabilities	-	53	-	-	-	341	-	394
Interest and debt expense	2,218	316	42	77	32	313	(2,289)	709
Foreign currency transaction (gains) losses	(19)	19	-	13	22	6	-	41
Total Costs and Expenses	2,211	19,698	42	90	54	30,256	(5,770)	46,581
Income (loss) from continuing operations before income taxes	6,632	9,388	4	-	(20)	18,382	(18,963)	15,423
Provision for income taxes	(779)	530	1	8	(2)	8,184	-	7,942
Income (Loss) From Continuing Operations	7,411	8,858	3	(8)	(18)	10,198	(18,963)	7,481
Income from discontinued operations	1,017	1,017	-	-	-	777	(1,794)	1,017
Net income (loss)	8,428	9,875	3	(8)	(18)	10,975	(20,757)	8,498
Less: net income attributable to noncontrolling interests	-	-	-	-	-	(70)	-	(70)
Net Income (Loss) Attributable to ConocoPhillips	$ 8,428	9,875	3	(8)	(18)	10,905	(20,757)	8,428
Comprehensive Income (Loss) Attributable to ConocoPhillips	$ 9,055	10,502	3	27	(4)	11,140	(21,668)	9,055

Year Ended December 31, 2011

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	$ -	20,606	-	-	-	43,590	-	64,196
Equity in earnings of affiliates	8,164	8,245	-	-	-	1,293	(16,463)	1,239
Gain on dispositions	-	261	-	-	-	109	-	370
Other income	-	98	-	-	-	166	-	264

Intercompany revenues	4	1,346	46	91	35	2,683	(4,205)	-
Total Revenues and Other Income	8,168	30,556	46	91	35	47,841	(20,668)	66,069
Costs and Expenses								
Purchased commodities	-	17,944	-	-	-	14,287	(2,434)	29,797
Production and operating expenses	-	1,126	-	-	-	5,363	(63)	6,426
Selling, general and administrative expenses	13	607	-	-	-	254	(9)	865
Exploration expenses	-	333	-	-	-	705	-	1,038
Depreciation, depletion and amortization	-	867	-	-	-	5,960	-	6,827
Impairments	-	38	-	-	-	283	-	321
Taxes other than income taxes	-	292	-	-	-	3,707	-	3,999
Accretion on discounted liabilities	-	48	-	-	-	374	-	422
Interest and debt expense	1,594	448	42	77	32	460	(1,699)	954
Foreign currency transaction (gains) losses	-	(16)	-	(10)	(35)	85	-	24
Total Costs and Expenses	1,607	21,687	42	67	(3)	31,478	(4,205)	50,673
Income from continuing operations before income taxes	6,561	8,869	4	24	38	16,363	(16,463)	15,396
Provision for income taxes	(561)	705	1	(1)	12	8,052	-	8,208
Income From Continuing Operations	7,122	8,164	3	25	26	8,311	(16,463)	7,188
Income from discontinued operations	5,314	5,314	-	-	-	4,868	(10,182)	5,314
Net income	12,436	13,478	3	25	26	13,179	(26,645)	12,502
Less: net income attributable to noncontrolling interests	-	-	-	-	-	(66)	-	(66)
Net Income Attributable to ConocoPhillips	$ 12,436	13,478	3	25	26	13,113	(26,645)	12,436
Comprehensive Income (Loss) Attributable to ConocoPhillips	$ 10,749	11,791	3	(6)	14	11,901	(23,703)	10,749

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	Millions of Dollars							
	Year Ended December 31, 2010							
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	$ -	21,531	-	-	-	34,684	-	56,215
Equity in earnings of affiliates	10,865	11,237	-	-	-	1,286	(22,012)	1,376
Gain on dispositions	-	370	-	-	-	5,193	-	5,563
Other income (loss)	1	191	-	-	(28)	17	-	181
Intercompany revenues	5	661	46	86	66	3,886	(4,750)	-
Total Revenues and Other Income	10,871	33,990	46	86	38	45,066	(26,762)	63,335
Costs and Expenses								
Purchased commodities	-	18,587	-	-	-	9,843	(3,576)	24,854
Production and operating expenses	-	1,328	-	-	-	4,923	(24)	6,227
Selling, general and administrative expenses	12	602	-	-	-	222	(27)	809
Exploration expenses	-	247	-	-	-	878	-	1,125
Depreciation, depletion and amortization	-	978	-	-	-	7,026	-	8,004
Impairments	-	-	-	-	-	81	-	81
Taxes other than income taxes	-	293	-	-	-	2,495	-	2,788
Accretion on discounted liabilities	-	41	-	-	-	368	-	409
Interest and debt expense	946	503	42	77	45	677	(1,123)	1,167
Foreign currency transaction (gains) losses	-	23	-	47	50	(124)	-	(4)
Total Costs and Expenses	958	22,602	42	124	95	26,389	(4,750)	45,460
Income (loss) from continuing operations before income taxes	9,913	11,388	4	(38)	(57)	18,677	(22,012)	17,875
Provision for income taxes	(333)	523	1	7	(6)	7,378	-	7,570
Income (Loss) From Continuing Operations	10,246	10,865	3	(45)	(51)	11,299	(22,012)	10,305
Income from discontinued operations	1,112	1,112	-	-	-	1,348	(2,460)	1,112
Net income (loss)	11,358	11,977	3	(45)	(51)	12,647	(24,472)	11,417
Less: net income attributable to noncontrolling interests	-	-	-	-	-	(59)	-	(59)
Net Income (Loss) Attributable to ConocoPhillips	$ 11,358	11,977	3	(45)	(51)	12,588	(24,472)	11,358
Comprehensive Income (Loss) Attributable to ConocoPhillips	$ 13,066	13,685	3	24	(19)	14,279	(27,972)	13,066

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Millions of Dollars

At December 31, 2012

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	$ 2	12	6	50	2	3,546	-	3,618
Restricted cash	748	-	-	-	-	-	-	748
Accounts and notes receivable	64	6,247	-	-	-	7,958	(5,087)	9,182
Inventories	-	57	-	-	-	908	-	965
Prepaid expenses and other current assets	19	847	-	1	-	8,609	-	9,476
Total Current Assets	833	7,163	6	51	2	21,021	(5,087)	23,989
Investments, loans and long-term receivables*	80,910	114,314	759	1,455	578	44,739	(217,749)	25,006
Net properties, plants and equipment	-	8,771	-	-	-	58,492	-	67,263
Intangibles	-	-	-	-	-	4	-	4
Other assets	55	216	-	2	3	606	-	882
Total Assets	$ 81,798	130,464	765	1,508	583	124,862	(222,836)	117,144
Liabilities and Stockholders Equity								
Accounts payable	$ -	9,067	-	4	1	6,028	(5,087)	10,013
Short-term debt	(5)	4	750	-	-	206	-	955
Accrued income and other taxes	-	104	-	3	-	3,259	-	3,366
Employee benefit obligations	-	485	-	-	-	257	-	742
Other accruals	209	636	9	15	4	1,494	-	2,367
Total Current Liabilities	204	10,296	759	22	5	11,244	(5,087)	17,443
Long-term debt	9,453	5,215	-	1,250	499	4,353	-	20,770
Asset retirement obligations and accrued environmental costs	-	1,250	-	-	-	7,697	-	8,947
Joint venture acquisition obligation	-	-	-	-	-	2,810	-	2,810
Deferred income taxes	15	598	-	16	7	12,549	-	13,185
Employee benefit obligations	-	2,464	-	-	-	882	-	3,346
Other liabilities and deferred credits*	30,938	19,916	-	117	50	21,174	(69,979)	2,216
Total Liabilities	40,610	39,739	759	1,405	561	60,709	(75,066)	68,717
Retained earnings	28,815	24,041	4	(78)	(73)	30,778	(48,149)	35,338
Other common stockholders equity	12,373	66,684	2	181	95	32,935	(99,621)	12,649
Noncontrolling interests	-	-	-	-	-	440	-	440
Total Liabilities and Stockholders Equity	$ 81,798	130,464	765	1,508	583	124,862	(222,836)	117,144

Balance Sheet At December 31, 2011

Assets								
Cash and cash equivalents	$ -	2,028	1	37	1	3,713	-	5,780
Short-term investments	-	-	-	-	-	581	-	581
Accounts and notes receivable	60	9,186	-	-	-	20,898	(13,618)	16,526
Inventories	-	2,239	-	-	-	2,392	-	4,631
	22	1,090	-	1	-	1,587	-	2,700

Prepaid expenses and other current assets								
Total Current Assets	82	14,543	1	38	1	29,171	(13,618)	30,218
Investments, loans and long-term receivables*	96,284	135,618	760	1,417	565	59,651	(260,512)	33,783
Net properties, plants and equipment	-	19,595	-	-	-	64,585	-	84,180
Goodwill	-	3,332	-	-	-	-	-	3,332
Intangibles	-	722	-	-	-	23	-	745
Other assets	64	301	-	2	3	602	-	972
Total Assets	$ 96,430	174,111	761	1,457	569	154,032	(274,130)	153,230
Liabilities and Stockholders Equity								
Accounts payable	$ 10	18,747	-	1	1	14,512	(13,618)	19,653
Short-term debt	892	27	-	-	-	94	-	1,013
Accrued income and other taxes	-	315	-	2	-	3,903	-	4,220
Employee benefit obligations	-	835	-	-	-	276	-	1,111
Other accruals	244	634	9	14	6	1,164	-	2,071
Total Current Liabilities	1,146	20,558	9	17	7	19,949	(13,618)	28,068
Long-term debt	10,951	3,599	749	1,250	498	4,563	-	21,610
Asset retirement obligations and accrued environmental costs	-	1,766	-	-	-	7,563	-	9,329
Joint venture acquisition obligation	-	-	-	-	-	3,582	-	3,582
Deferred income taxes	(5)	3,982	-	11	9	14,043	-	18,040
Employee benefit obligations	-	3,092	-	-	-	976	-	4,068
Other liabilities and deferred credits*	25,959	40,479	-	104	29	20,047	(83,834)	2,784
Total Liabilities	38,051	73,476	758	1,382	543	70,723	(97,452)	87,481
Retained earnings	42,550	34,921	1	(70)	(55)	29,821	(58,119)	49,049
Other common stockholders equity	15,829	65,714	2	145	81	52,978	(118,559)	16,190
Noncontrolling interests	-	-	-	-	-	510	-	510
Total Liabilities and Stockholders Equity	$ 96,430	174,111	761	1,457	569	154,032	(274,130)	153,230

** Includes intercompany loans.*

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	Millions of Dollars							
Statement of Cash Flows	Year Ended December 31, 2012							
	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 operating activities	$ 3,947	14,992	5	13	1	7,750	(13,250)	13,458
Net cash provided by (used in) discontinued operations	-	479	-	-	-	(15)	-	464
Net Cash Provided by Operating Activities	3,947	15,471	5	13	1	7,735	(13,250)	13,922
Cash Flows From Investing Activities								
Capital expenditures and investments	(317)	(5,994)	-	-	-	(12,433)	4,572	(14,172)
Proceeds from asset dispositions	14	937	-	-	-	2,126	(945)	2,132
Net purchases of short-term investments	-	-	-	-	-	597	-	597
Long-term advances/loans related parties	-	(85)	-	-	-	(2,920)	3,005	-
Collection of advances/loans related parties	-	150	-	-	-	5,884	(5,920)	114
Other	-	442	-	-	-	379	-	821
Net cash used in continuing investing activities	(303)	(4,550)	-	-	-	(6,367)	712	(10,508)
Net cash provided by (used in) discontinued operations	-	(232)	-	-	-	7,213	(8,100)	(1,119)
Net Cash Provided by (Used in) Investing Activities	(303)	(4,782)	-	-	-	846	(7,388)	(11,627)
Cash Flows From Financing Activities								
Issuance of debt	-	5,033	-	-	-	69	(3,106)	1,996
Repayment of debt	(2,474)	(14,033)	-	-	-	(179)	14,121	(2,565)
Special cash distribution from Phillips 66	7,818	-	-	-	-	-	-	7,818
Change in restricted cash	(748)	-	-	-	-	-	-	(748)
Issuance of company common stock	138	-	-	-	-	-	-	138
Repurchase of company common stock	(5,098)	-	-	-	-	-	-	(5,098)
Dividends paid on common stock	(3,278)	-	-	-	-	(7,909)	7,909	(3,278)
Other	-	118	-	-	-	(1,771)	928	(725)
Net cash used in continuing financing activities	(3,642)	(8,882)	-	-	-	(9,790)	19,852	(2,462)
Net cash provided by (used in) discontinued operations	-	(3,786)	-	-	-	981	786	(2,019)
Net Cash Used in Financing Activities	(3,642)	(12,668)	-	-	-	(8,809)	20,638	(4,481)
	-	(37)	-	-	-	61	-	24

Effect of Exchange Rate Changes on Cash and Cash Equivalents								
Net Change in Cash and Cash Equivalents	2	(2,016)	5	13	1	(167)	-	(2,162)
Cash and cash equivalents at beginning of period	-	2,028	1	37	1	3,713	-	5,780
Cash and Cash Equivalents at End of Period	$ 2	12	6	50	2	3,546	-	3,618
Statement of Cash Flows			Year Ended December 31, 2011					
Cash Flows From Operating Activities								
Net cash provided by (used in) continuing operating activities	$ 14,669	(1,805)	1	12	(7)	4,427	(3,344)	13,953
Net cash provided by (used in) discontinued operations	-	(2,359)	-	-	-	8,052	-	5,693
Net Cash Provided by (Used in) Operating Activities	14,669	(4,164)	1	12	(7)	12,479	(3,344)	19,646
Cash Flows From Investing Activities								
Capital expenditures and investments	-	(1,504)	-	-	-	(9,710)	-	(11,214)
Proceeds from asset dispositions	-	318	-	-	-	1,874	-	2,192
Net purchases of short-term investments	-	-	-	-	-	400	-	400
Long-term advances/loans related parties	-	(916)	-	(4)	-	(4,553)	5,473	-
Collection of advances/loans related parties	-	993	-	-	-	8,340	(9,235)	98
Other	-	6	-	-	-	44	-	50
Net cash used in continuing investing activities	-	(1,103)	-	(4)	-	(3,605)	(3,762)	(8,474)
Net cash provided by (used in) discontinued operations	-	2,376	-	-	-	(9,117)	8,200	1,459
Net Cash Provided by (Used in) Investing Activities	-	1,273	-	(4)	-	(12,722)	4,438	(7,015)
Cash Flows From Financing Activities								
Issuance of debt	-	12,758	-	-	4	827	(13,589)	-
Repayment of debt	-	(8,657)	-	-	-	(1,426)	9,149	(934)
Issuance of company common stock	96	-	-	-	-	-	-	96
Repurchase of company common stock	(11,123)	-	-	-	-	-	-	(11,123)
Dividends paid on common stock	(3,633)	-	-	-	-	(3,051)	3,052	(3,632)
Other	(9)	119	-	-	-	(794)	-	(684)
Net cash provided by (used in) continuing financing activities	(14,669)	4,220	-	-	4	(4,444)	(1,388)	(16,277)
Net cash used in discontinued operations	-	(18)	-	-	-	(304)	294	(28)
Net Cash Provided by (Used in) Financing Activities	(14,669)	4,202	-	-	4	(4,748)	(1,094)	(16,305)
	-	(1)	-	-	-	1	-	-

Effect of Exchange Rate Changes on Cash and Cash Equivalents									
Net Change in Cash and Cash Equivalents		-	1,310	1	8	(3)	(4,990)	-	(3,674)
Cash and cash equivalents at beginning of period		-	718	-	29	4	8,703	-	9,454
Cash and Cash Equivalents at End of Period	$	-	2,028	1	37	1	3,713	-	5,780

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Millions of Dollars

Statement of Cash Flows Year Ended December 31, 2010

	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities								
Net cash provided by (used in) continuing operating activities	$ 7,901	1,962	-	11	(3)	6,655	(2,513)	14,013
Net cash provided by discontinued operations	-	349	-	-	-	2,683	-	3,032
Net Cash Provided by (Used in) Operating Activities	7,901	2,311	-	11	(3)	9,338	(2,513)	17,045
Cash Flows From Investing Activities								
Capital expenditures and investments	-	(1,120)	-	-	-	(6,738)	323	(7,535)
Proceeds from asset dispositions	-	789	-	-	-	14,020	(99)	14,710
Net sales of short-term investments	-	-	-	-	-	(982)	-	(982)
Long-term advances/loans related parties	-	(135)	-	-	-	(2,284)	2,301	(118)
Collection of advances/loans related parties	-	87	-	-	384	1,379	(1,755)	95
Other	-	28	-	-	-	190	-	218
Net cash provided by (used in) continuing investing activities	-	(351)	-	-	384	5,585	770	6,388
Net cash used in discontinued operations	-	(931)	-	-	-	(792)	-	(1,723)
Net Cash Provided by (Used in) Investing Activities	-	(1,282)	-	-	384	4,793	770	4,665
Cash Flows From Financing Activities								
Issuance of debt	-	2,159	-	-	-	260	(2,301)	118
Repayment of debt	(990)	(2,642)	-	-	(378)	(3,039)	1,755	(5,294)
Issuance of company common stock	133	-	-	-	-	-	-	133
Repurchase of company common stock	(3,866)	-	-	-	-	-	-	(3,866)
Dividends paid	(3,175)	-	-	-	-	(2,666)	2,666	(3,175)
Other	(3)	52	-	-	-	(782)	27	(706)
Net cash used in continuing financing activities	(7,901)	(431)	-	-	(378)	(6,227)	2,147	(12,790)
Net cash provided by (used in) discontinued operations	-	(18)	-	-	-	240	(251)	(29)
Net Cash Used in Financing Activities	(7,901)	(449)	-	-	(378)	(5,987)	1,896	(12,819)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	16	-	-	-	5	-	21
	-	596	-	11	3	8,149	153	8,912

Net Change in Cash and Cash Equivalents									
Cash and cash equivalents at beginning of period		-	122	-	18	1	554	(153)	542
Cash and Cash Equivalents at End of Period	$	-	718	-	29	4	8,703	-	9,454

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

None.

Item 9A. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in reports we file or submit under the Securities Exchange Act of 1934, as amended (the Act), is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. As of December 31, 2012, with the participation of our management, our Chairman 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 Act, of ConocoPhillips disclosure controls and procedures (as defined in Rule 13a-15(e) of the Act). Based upon that evaluation, our Chairman and Chief Executive Officer and our Executive Vice President, Finance and Chief Financial Officer concluded that our disclosure controls and procedures were operating effectively as of December 31, 2012.

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Act, in the period covered by this report 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 72 and is incorporated herein by reference.

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

This report is included in Item 8 on page 74 and is incorporated herein by reference.

Item 9B. OTHER INFORMATION

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding our executive officers appears in Part I of this report on pages 28 and 29.

Code of Business Ethics and Conduct for Directors and Employees

We have a Code of Business Ethics and Conduct for Directors and Employees (Code of Ethics), including our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. We have posted a copy of our Code of Ethics on the Corporate Governance section of our Internet Web site at *www.conocophillips.com* (within the Investor Relations>Governance section). Any waivers of the Code of Ethics must be approved, in advance, by our full Board of Directors. Any amendments to, or waivers from, the Code of Ethics that apply to our executive officers and directors will be posted on the Corporate Governance section of our Internet Web site.

All other information required by Item 10 of Part III will be included in our Proxy Statement relating to our 2013 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2013, 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 2013 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2013, 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 2013 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2013, 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 2013 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2013, 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 2013 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2013, and is incorporated herein by reference.*

**Except for information or data specifically incorporated herein by reference under Items 10 through 14, other information and data appearing in our 2013 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 Supplementary Data
The financial statements and supplementary information listed in the Index to Financial Statements, which appears on page 71, are filed as part of this annual report.

2. Financial Statement Schedules
Schedule II Valuation and Qualifying Accounts, appears below. All other schedules are omitted because they are not required, not significant, not applicable or the information is shown in another schedule, the financial statements or the notes to consolidated financial statements.

3. Exhibits
The exhibits listed in the Index to Exhibits, which appears on pages 161 through 166 are filed as part of this annual report.

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS (Consolidated)

ConocoPhillips

	Millions of Dollars				
Description	Balance at January 1	Charged to Expense	Other(a)	Deductions	Balance at December 31
2012					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	**$ 30**	**(4)**	**(13)**	**(3)(b)**	**10**
Deferred tax asset valuation allowance	**1,487**	**369**	**(447)**	**(64)**	**1,345**
Included in other liabilities:					
Restructuring accruals	**48**	**9**	**(5)**	**(35)(c)**	**17**
2011					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 32	2		(4)(b)	30
Deferred tax asset valuation allowance	1,400	174	(31)	(56)	1,487
Included in other liabilities:					
Restructuring accruals	105	25	(1)	(81)(c)	48
2010					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 76	(31)	(1)	(12)(b)	32
Deferred tax asset valuation allowance	1,540	414	(12)	(542)	1,400
Included in other liabilities:					
Restructuring accruals	73	78	1	(47)(c)	105

(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	Separation and Distribution Agreement Between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
3.1	Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395).
3.2	Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips (incorporated by reference to Exhibit 3.2 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987).
3.3	Amended and Restated By-Laws of ConocoPhillips, as amended and restated as of February 10, 2012 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed on February 16, 2012; File No. 001-32395).
	ConocoPhillips and its subsidiaries are parties to several debt instruments under which the total amount of securities authorized does not exceed 10 percent of the total assets of ConocoPhillips and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, ConocoPhillips agrees to furnish a copy of such instruments to the SEC upon request.
10.1	1986 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.2	1990 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.3	Annual Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.4	Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(g) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1999; File No. 1-720).
10.5	Amendment and Restatement of ConocoPhillips Supplemental Executive Retirement Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.14 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).

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Exhibit Number	Description
10.6	Non-Employee Director Retirement Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.18 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.7	Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.19 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.8	Key Employee Missed Credited Service Retirement Plan of ConocoPhillips (incorporated by reference to Exhibit 10.10 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.9	Phillips Petroleum Company Stock Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.22 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.10	Amendment and Restatement of ConocoPhillips Key Employee Supplemental Retirement Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.13 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.11.1	Amendment and Restatement of Defined Contribution Make-Up Plan of ConocoPhillips Title I, dated April 19, 2012 (incorporated by reference to Exhibit 10.11.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.11.2	Amendment and Restatement of Defined Contribution Make-Up Plan of ConocoPhillips Title II, dated April 19, 2012 (incorporated by reference to Exhibit 10.11.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.11.3	First Amendment to the Defined Contribution Make-Up Plan of ConocoPhillips Title II, dated October 11, 2012 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2012; File No. 001-32395).
10.12	2002 Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.13	Amendment and Restatement of 1998 Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.14	Amendment and Restatement of 1998 Key Employee Stock Performance Plan of ConocoPhillips (incorporated by reference to Exhibit 10.28 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.15	Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips (incorporated by reference to Exhibit 10.17 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.16	ConocoPhillips Form Indemnity Agreement with Directors (incorporated by reference to Exhibit 10.34 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).

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Exhibit Number	Description
10.17.1	Rabbi Trust Agreement dated December 17, 1999 (incorporated by reference to Exhibit 10.11 of the Annual Report of ConocoPhillips Holding Company on Form 10-K for the year ended December 31, 1999; File No. 001-14521).
10.17.2	Amendment to Rabbi Trust Agreement dated February 25, 2002 (incorporated by reference to Exhibit 10.39.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.18.1	ConocoPhillips Directors Charitable Gift Program (incorporated by reference to Exhibit 10.40 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987).
10.18.2	First and Second Amendments to the ConocoPhillips Directors Charitable Gift Program (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395).
10.19	ConocoPhillips Matching Gift Plan for Directors and Executives (incorporated by reference to Exhibit 10.41 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987).
10.20.1	Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips Title I, dated April 19, 2012 (incorporated by reference to Exhibit 10.12.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.20.2	Amendment and Restatement of Key Employee Deferred Compensation Plan of ConocoPhillips Title II, dated April 19, 2012 (incorporated by reference to Exhibit 10.12.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.20.3	First Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips Title II (incorporated by reference to Exhibit 10.20.3 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395).
10.20.4	Second Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips Title II (incorporated by reference to Exhibit 10.20.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395).
10.21	Amendment and Restatement of ConocoPhillips Key Employee Change in Control Severance Plan, dated October 11, 2012 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2012; File No. 001-32395).
10.22	ConocoPhillips Executive Severance Plan (incorporated by reference to Exhibit 10.23 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.23.1	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).
10.23.2	Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).

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Exhibit Number	Description
10.23.3	Form of Performance Share Unit Award Agreement under the Performance Share Program under the 2004 Omnibus 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, 2008; File No. 001-32395).
10.24	Omnibus Amendments to certain ConocoPhillips employee benefit plans, adopted December 7, 2007 (incorporated by reference to Exhibit 10.30 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2007; File No. 001-32395).
10.25	2009 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips Proxy Statement on Schedule 14A relating to the 2009 Annual Meeting of Shareholders; File No. 001-32395).
10.26.1	2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips Proxy Statement on Schedule 14A relating to the 2011 Annual Meeting of Shareholders; File No. 001-32395).
10.26.2	Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective February 9, 2012 (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2012; File No. 001-32395).
10.26.3	Form of Restricted Stock Units Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective April 4, 2012 (incorporated by reference to Exhibit 10.6 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.26.4	Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective May 8, 2012 (incorporated by reference to Exhibit 10.7 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.26.5*	Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 18, 2012.
10.26.6*	Form of Performance Share Unit Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013.
10.26.7*	Form of Performance Share Unit Agreement Canada under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013.
10.26.8*	Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013.
10.26.9*	Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013.
10.27	Amendment and Restatement of Annex to Nonqualified Deferred Compensation Arrangements of ConocoPhillips, dated April 19, 2012 (incorporated by reference to Exhibit 10.8 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).

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Exhibit Number	Description
10.28	Amendment, Change of Sponsorship, and Restatement of Certain Nonqualified Deferred Compensation Plans of ConocoPhillips, dated April 19, 2012 (incorporated by reference to Exhibit 10.10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.29	Amendment and Restatement of the Burlington Resources Inc. Management Supplemental Benefits Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.9 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.30	Indemnification and Release Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
10.31	Intellectual Property Assignment and License Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.2 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
10.32	Tax Sharing Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.3 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
10.33	Employee Matters Agreement between ConocoPhillips and Phillips 66, dated April 12, 2012 (incorporated by reference to Exhibit 10.4 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
10.34	Transition Services Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.5 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
10.35	ConocoPhillips Clawback Policy dated October 3, 2012 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2012; File No. 001-32395).
12*	Computation of Ratio of Earnings to Fixed Charges.
21*	List of Subsidiaries of ConocoPhillips.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of DeGolyer and MacNaughton.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32*	Certifications pursuant to 18 U.S.C. Section 1350.
99*	Report of DeGolyer and MacNaughton.

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Exhibit Number	Description
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Labels Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.

* Filed herewith.

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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 19, 2013

/s/ Ryan M. Lance
Ryan M. Lance

Chairman of the Board of Directors

and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 19, 2013, on behalf of the registrant by the following officers in the capacity indicated and by a majority of directors.

Signature	Title
/s/ Ryan M. Lance Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer (Principal executive officer)
/s/ Jeff W. Sheets Jeff W. Sheets	Executive Vice President, Finance and Chief Financial Officer (Principal financial officer)
/s/ Glenda M. Schwarz Glenda M. Schwarz	Vice President and Controller (Principal accounting officer)

/s/ Richard L. Armitage Richard L. Armitage	Director
/s/ Richard H. Auchinleck Richard H. Auchinleck	Director
/s/ James E. Copeland, Jr. James E. Copeland, Jr.	Director
/s/ Jody L. Freeman Jody L. Freeman	Director
/s/ Mohd H. Marican Mohd H. Marican	Director
/s/ Robert A. Niblock Robert A. Niblock	Director
/s/ Harald J. Norvik Harald J. Norvik	Director
/s/ William K. Reilly William K. Reilly	Director
/s/ William E. Wade, Jr. William E. Wade, Jr.	Director