2013

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, 2013**

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, 2013, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $60.50, was $74.0 billion.

The registrant had 1,226,104,592 shares of common stock outstanding at January 31, 2014.

Documents incorporated by reference:

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 13, 2014 (Part III)

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PART I

Unless otherwise indicated, "the company," "we," "our," "us" and "ConocoPhillips" are used in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. Items 1 and 2—Business and Properties, contain forward-looking statements including, without limitation, statements relating to our plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The words "anticipate," "estimate," "believe," "budget," "continue," "could," "intend," "may," "plan," "potential," "predict," "seek," "should," "will," "would," "expect," "objective," "projection," "forecast," "goal," "guidance," "outlook," "effort," "target" and similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company's disclosures under the heading "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 71.

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 asset disposition program, in the fourth quarter of 2013, we completed the sale of our interest in the North Caspian Sea Production Sharing Agreement (Kashagan) and the sale of our Algeria business, and we have agreements to sell our Nigeria business. Results of operations related to Phillips 66, Kashagan, Algeria and Nigeria have been classified as discontinued operations in all periods presented in this Annual Report on Form 10-K. For additional information, see Note 3—Discontinued Operations, in the Notes to Consolidated Financial Statements.

Headquartered in Houston, Texas, we have operations and activities in 27 countries. Our key focus areas include safely operating producing assets, executing major developments and exploring for new resources in promising areas. Our portfolio includes resource-rich North American shale and oil sands assets; lower-risk legacy assets in North America, Europe, Asia and Australia; several major international developments; and a growing inventory of global conventional and unconventional exploration prospects.

At December 31, 2013, ConocoPhillips employed approximately 18,400 people worldwide.

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SEGMENT AND GEOGRAPHIC INFORMATION

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

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, 2013, our continuing operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, Qatar, Libya and Russia.

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.

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 83 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 following summary reserves table.

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Net Proved Reserves at December 31	Millions of Barrels of Oil Equivalent 2013	2012	2011
Crude oil			
Consolidated operations	**2,659**	2,684	2,617
Equity affiliates	**90**	95	124
Total Crude Oil	**2,749**	2,779	2,741
Natural gas liquids			
Consolidated operations	**699**	646	670
Equity affiliates	**45**	48	51
Total Natural Gas Liquids	**744**	694	721
Natural gas			
Consolidated operations	**2,710**	2,726	2,933
Equity affiliates	**688**	543	553
Total Natural Gas	**3,398**	3,269	3,486
Bitumen			
Consolidated operations	**579**	506	530
Equity affiliates	**1,451**	1,394	909
Total Bitumen	**2,030**	1,900	1,439
Total consolidated operations	**6,647**	6,562	6,750
Total equity affiliates	**2,274**	2,080	1,637
Total company	**8,921**	8,642	8,387

Total production from continuing operations, including our share of equity affiliates, for 2013 averaged 1,502 thousand barrels of oil equivalent per day (MBOED), a 2 percent decrease compared with 1,527 MBOED in 2012. The decrease was mainly due to normal field decline, asset dispositions, shut-in Libya production, due to the closure of the Es Sider crude oil export terminal, and higher unplanned downtime. These decreases were partially offset by new production from major developments, mainly from shale plays in the Lower 48, the ramp-up of production from new phases at Christina Lake in Canada, and early production in Malaysia; higher production in China; and increased conventional drilling and well performance, mostly in the Lower 48, western Canada and Norway. Adjusted for dispositions, downtime and the impact from the closure of the Es Sider Terminal in Libya, production grew by 30 MBOED, or 2 percent, compared with 2012.

Our total realized price from continuing operations remained relatively flat in 2013, from $67.68 per BOE in 2012, compared with $67.62 per BOE in 2013. Our worldwide annual average crude oil sales price from continuing operations decreased 2 percent in 2013, from $105.72 per barrel in 2012 to $103.32 per barrel in 2013. Additionally, our worldwide average annual natural gas liquids prices from continuing operations decreased 11 percent, from $46.36 per barrel in 2012 to $41.42 per barrel in 2013. Our average annual worldwide natural gas sales price from continuing operations increased 11 percent, from $5.48 per thousand cubic feet in 2012 to $6.11 per thousand cubic feet in 2013. Average annual bitumen prices decreased 1 percent, from $53.91 per barrel in 2012 to $53.27 per barrel in 2013.

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ALASKA

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids, natural gas and LNG. We are the largest crude oil and natural gas producer in Alaska and have major ownership interests in two of North America’s largest oil fields located on Alaska’s North Slope: Prudhoe Bay and Kuparuk. We also have a significant operating interest in the Alpine Field, located on the Western North Slope. Additionally, we are one of Alaska’s largest owners of state and federal exploration leases, with approximately 0.9 million net undeveloped acres at year-end 2013. Approximately 0.5 million of these acres are located in the National Petroleum Reserve—Alaska (NPRA) and 0.3 million are located in the Chukchi Sea. In 2013, Alaska operations contributed 23 percent of our worldwide liquids production and 1 percent of our natural gas production.

			2013		
	Interest	Operator	Liquids MBD*	Natural Gas MMCFD**	Total MBOED
Average Daily Net Production					
Greater Prudhoe Area	36.1%	BP	101	5	102
Greater Kuparuk Area	52.2-55.5	ConocoPhillips	53	-	53
Western North Slope	78	ConocoPhillips	39	1	39
Cook Inlet Area	33.3-100	ConocoPhillips	-	37	6
Total Alaska			193	43	200

** Thousands of barrels per day.*
*** 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 consists of the Kuparuk Field and four satellite fields: Tarn, Tabasco, Meltwater and West Sak. Kuparuk is located 40 miles west of Prudhoe Bay. Field installations include three central production facilities which separate oil, natural gas and water, as well as a separate seawater treatment plant. New rotary-drilled wells and sidetracks from existing well bores utilizing coiled-tubing drilling are the primary means for development drilling at Kuparuk.

The successful Shark Tooth delineation well extended the known Kuparuk accumulation to the southwestern area of the Kuparuk Field. As a result, plans for the future development of Drill Site 2S are progressing, with project sanction targeted for late 2014 and first production estimated in late 2015.

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. Construction is progressing on Alpine West CD5, a drill site to access the western extension of the Alpine reservoir, in the NPRA. Initial production is anticipated in late 2015, with net peak production estimated at 10 MBOED in 2016.

The Greater Mooses Tooth Unit, the first unit established entirely within the NPRA, was formed in 2008. We are progressing development planning for the Greater Mooses Tooth #1 (GMT1) drill site in the Greater Mooses Tooth Unit. We filed permitting applications for GMT1 in July 2013, and project sanction is targeted for late 2014. GMT1 is planned to be connected by road to the CD5 drill site, and production will be transported by pipeline to the existing Alpine facilities for processing. Construction is estimated to begin in 2016, with first production anticipated in late 2017. We are evaluating further exploration and development potential in the NPRA.

Cook Inlet Area

We operate the North Cook Inlet Unit, the Beluga River Unit, and the Kenai LNG Facility in the Cook Inlet Area. We have a 100 percent interest in the North Cook Inlet Unit and the Kenai LNG Facility, while we own 33.3 percent of the Beluga River Unit. Both units produce natural gas, and our share of production is currently sold to local utilities.

The Kenai LNG Facility includes a 1.3 million-tons-per-year capacity plant, which historically manufactured LNG for sale to utility companies in Japan, as well as docking and loading facilities, which enable the LNG to be transported by tanker. Although our LNG export license expired in March 2013, the plant is operational and in stand-by mode, maintaining the flexibility to resume limited operations. Due to a change in market conditions, including additional gas supplies, we submitted applications in December 2013 to the U.S. Department of Energy to resume LNG exports from the Kenai LNG Facility.

Point Thomson

We own a 5 percent interest in the Point Thomson Unit, 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).

More Alaska Production Act (MAPA)

Following the April 2013 enactment of revised oil tax legislation, MAPA, we have increased our exploration and development investments and activities on the North Slope by adding rigs and progressing new development opportunities. We will continue to work with co-owners to identify additional opportunities to increase our investments in Alaska.

Alaska LNG (AKLNG)

During 2012, we, along with affiliates of Exxon Mobil Corporation, BP p.l.c. and TransCanada Corporation (collectively, the “AKLNG co-venturers”), began evaluating a potential LNG project which would export and liquefy natural gas from Alaska’s North Slope and deliver it to market. The AKLNG Project concept is an integrated LNG project consisting of a liquefaction plant, including marine terminal facilities and auxiliary marine vessels, located in south-central Alaska; a natural gas treatment plant, located on the North Slope; and an estimated 800-mile natural gas pipeline, which would connect the two plants.

In October 2013, the AKLNG co-venturers selected the Nikiski area on the Kenai Peninsula as the lead site for the proposed AKLNG natural gas liquefaction plant and terminal. On January 14, 2014, the AKLNG co-venturers, the Commissioners of the Alaska Departments of Revenue and Natural Resources, and the Alaska Gasline Development Corporation, a state-owned corporation, signed a Heads of Agreement (HOA) for the AKLNG Project. The HOA provides a roadmap of how the parties intend to progress the project, including proposed terms for participation by the State of Alaska as an equity owner, proposed fiscal and regulatory terms, and proposed terms for expansion of project components. One of the initial steps in the HOA is enactment of general legislation by the State of Alaska, as well as further commercial agreements, which would be subject to approval by the Alaska legislature. Significant engineering, technical, regulatory, fiscal, commercial and permitting issues would need to be resolved prior to a final investment decision on the potential 17 million-tons-per-year, $45 billion to $65 billion (gross) project. Following the enabling legislation, we anticipate commencing preliminary front-end engineering and development, currently estimated in the second quarter of 2014.

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Exploration
In April 2013, we suspended our plans to drill an exploration well in the Chukchi Sea in 2014, in light of the uncertainties of evolving federal regulatory requirements and operational permitting standards. Once these requirements are clarified and better defined, we will re-evaluate plans for drilling in the Chukchi Sea.

In 2013, we drilled and flow-tested a new discovery at the Cassin prospect, located in the Bear Tooth Unit in the northeast NPRA, and we also tested the Moraine play on the western flank of the Kuparuk Field. The results for both wells are currently under evaluation. Additionally, we plan to drill two exploration wells within the Greater Mooses Tooth Unit in 2014: the Rendezvous 3, which is currently drilling, and Flattop-1, which is expected to be spud later in the first quarter of 2014.

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 29.1 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 and chartering third-party vessels, as necessary. The tankers deliver oil from Valdez, Alaska, to refineries on the west coast of the United States.

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LOWER 48 AND LATIN AMERICA

The Lower 48 and Latin America segment primarily consists of operations located in the U.S. Lower 48 states, as well as exploration activities in the Gulf of Mexico and Colombia. As a result of increasing shale opportunities and a low natural gas price environment, we have directed our investments toward high-margin, liquids-rich plays, predominantly in the Lower 48.

Lower 48
We hold 15.3 million net onshore and offshore acres in the Lower 48. In 2013, the Lower 48 contributed 29 percent of our worldwide liquids production and 38 percent of our natural gas production.

			2013		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Eagle Ford	Various %	Various	94	147	119
Gulf of Mexico	Various	Various	13	14	15
Gulf Coast—Other	Various	Various	10	221	47
Total Gulf Coast			117	382	181
Permian	Various	Various	34	116	53
Barnett	Various	Various	7	51	16
Anadarko Basin	Various	Various	8	121	28
Total Mid-Continent			49	288	97
Bakken	Various	Various	29	25	33
Wyoming/Uinta	Various	Various	-	103	17
Rockies—Other	Various	Various	3	-	3
Total Rockies			32	128	53
San Juan	Various	Various	45	692	160
Total U.S. Lower 48			243	1,490	491

Onshore
We hold 13.1 million net acres of onshore conventional and unconventional acreage in the Lower 48, the majority of which is either held by production or owned by the Company. Our unconventional holdings total approximately 2.7 million net acres in the following areas:

- 620,000 net acres in the Bakken, located in North Dakota and Eastern Montana;
- 221,000 net acres in the Eagle Ford, located in South Texas;
- 240,000 net acres in the Permian, located in West Texas and southeastern New Mexico;
- 130,000 net acres in the Niobrara, located in northeastern Colorado;
- 900,000 net acres in the San Juan Basin, located in northwestern New Mexico and southwestern Colorado;
- 65,000 net acres in the Barnett, located in north central Texas; and
- 541,000 net acres in other unconventional exploration plays.

The majority of our 2013 onshore production originated from San Juan, Eagle Ford, Permian, Bakken, Anadarko, Lobo and Barnett. Onshore activities in 2013 were centered mostly on continued development and optimization of emerging and existing assets, with an emphasis on areas with higher-margin, liquids-rich production, particularly in growing unconventional plays. Our major focus areas in 2013 included the following:

- Eagle Ford—Exploration and development continued in 2013 in the Eagle Ford. In 2013, we increased production by 70 percent, compared to 2012; drilled 164 exploration and development wells; connected 225 wells; and achieved net peak production of 141 MBOED, compared with 103 MBOED in 2012. We also had 11 operated rigs drilling throughout 2013.
- Bakken—The Bakken experienced a significant increase in activity in 2013. We drilled 126 operated wells during the year, of which 85 were brought online. We also increased our operated rig count to 11 and improved our efficiency with pad drilling. As a result, we achieved net peak production of more than 40 MBOED in 2013, compared with approximately 25 MBOED in 2012.
- San Juan Basin—The San Juan Basin 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 net acres of oil and gas leases by production in San Juan, where we continue to pursue conventional development opportunities. This also includes approximately 900,000 net unconventional acres of lease rights, where we are advancing the assessment of the Mancos shale play.
- Permian Basin—the Permian Basin is another area where we are leveraging our conventional legacy position by utilizing new technology to improve the ultimate recovery and value from these fields. This technology will also identify new, unconventional plays across the region. We hold approximately 1.0 million net acres in the Permian, which includes 240,000 net unconventional acres.

Gulf of Mexico
At year-end 2013, 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 operated working interest in the Magnolia Field in Garden Banks Blocks 783 and 784.
- 15.9 percent nonoperated working interest in the unitized Ursa Field located in the Mississippi Canyon Area.
- 15.9 percent nonoperated working interest in the Princess Field, a northern, subsalt extension of the Ursa Field.
- 12.4 percent nonoperated working 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 added approximately 430,000 net acres to our position in 2013, bringing our total acreage position to 2.1 million acres at December 31, 2013. Since 2011, we have nearly doubled our acreage footprint in the deepwater Gulf of Mexico and currently rank in the top five deepwater leaseholders. In 2013, we announced two new oil discoveries in the deepwater Lower Tertiary play at Coronado and Gila, adding to the existing Shenandoah and Tiber discoveries made in 2009.

  We own a 30 percent working interest in the Shenandoah discovery. The results of the Shenandoah appraisal well were announced in 2013 and confirmed Shenandoah as a significant oil discovery. The well encountered more than 1,000 feet of net pay in high-quality, Lower Tertiary-aged reservoirs. We plan to participate in further appraisal of Shenandoah in 2014. The Coronado exploration well encountered more than 400 feet of net pay and will require further appraisal. We hold a 35 percent working interest in Coronado. In 2013, we acquired a 20 percent interest in the Gila Prospect, located in the Keathley Canyon section of the Gulf of Mexico. The Gila exploration well was announced as a discovery in 2013 and is expected to be appraised in 2014.

Ongoing drilling activities at the end of 2013 included a Tiber appraisal well, in which we own an 18 percent working interest, a Coronado appraisal well and the Deep Nansen exploration well. We hold a 12.5 percent interest in the Deep Nansen well. We plan to evaluate the results of these wells in the first half of 2014.

The nonoperated Ardennes wildcat well and the ConocoPhillips-operated Thorn wildcat well were declared dry holes in 2013.

In support of our intentions to grow our Gulf of Mexico exploration program, we secured access to two new-build deepwater drillships, which we anticipate will be delivered to the Gulf of Mexico in 2014 and 2015. The drillships will provide rig availability for our operated drilling program.

- *Unconventional Exploration*
  In 2013, we actively pursued the exploration and appraisal of our existing unconventional resource plays, including the Eagle Ford in the Western Gulf Basin, the Bakken in the Williston Basin, the Barnett in the Fort Worth Basin, the Niobrara play in the Denver-Julesburg Basin, Wolfcamp and Bone Springs in the Delaware Basin, Wolfcamp in the Midland Basin, and the Mancos in the San Juan Basin. During 2013, we acquired approximately 61,000 net additional acres in various resource plays across the Lower 48, which included the Eagle Ford, Niobrara and Permian plays, further expanding our significant acreage position in Lower 48 shale plays to approximately 2.7 million net acres.

  During 2013, we drilled a total of 25 unconventional wells in the Niobrara, Bone Springs and Wolfcamp plays. In 2014, we will continue to actively explore and appraise unconventional plays in the Lower 48, with a focus on Bone Springs, Wolfcamp and Niobrara. We will also continue to assess new opportunities in unconventional plays.

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. In July 2013, we agreed with Freeport LNG to terminate this agreement, subject to Freeport LNG obtaining regulatory approval and project financing for an LNG liquefaction and export facility in Texas, in which we are not a participant. Upon satisfaction of these conditions, currently expected to occur in the second half of 2014, we will pay Freeport LNG a termination fee of approximately $600 million. Freeport LNG will repay the outstanding ConocoPhillips loan used by Freeport LNG to partially fund the original construction of the terminal. These transactions, plus miscellaneous items, will result in a one-time net cash outflow of approximately $80 million for us. When the agreement becomes effective, we also expect to recognize an after-tax charge to earnings of approximately $540 million. At that time, our terminal regasification capacity will be reduced from 0.9 billion cubic feet per day to 0.4 billion cubic feet per day, until July 1, 2016, at which time it will be reduced to zero. As a result of this transaction, we anticipate saving approximately $50 to $60 million per year in operating costs over the next 19 years. For additional information, see Note 4—Variable Interest Entities (VIEs), in the Notes to Consolidated Financial Statements.

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.

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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.
- Helena Stabilization Plant—We operate and own the Helena Stabilization Plant, a 60,000 barrel-per-day condensate stabilization facility located in Kenedy, Texas.
- Bordovsky Stabilization Plant—We operate and own the Bordovsky Stabilization Plant, a 15,000 barrel-per-day condensate stabilization facility located in Kenedy, Texas.
- Sugarloaf Stabilization Plant—We operate and own an 87.5 percent interest in the Sugarloaf Stabilization Plant, a 15,000 barrel-per-day condensate stabilization facility located near Pawnee, Texas.

Asset Dispositions

During 2013, we sold the majority of our producing zones in the Cedar Creek Anticline, located in southwestern North Dakota and eastern Montana; certain properties located in southwest Louisiana; and our 39 percent equity interest in Phoenix Park Gas Processors Limited, located in Trinidad and Tobago. For additional information, see Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

Colombia

Unconventional Exploration

During 2013, we entered into a farm-in agreement with Canacol Energy Ltd. to acquire a 70 percent working interest for deep rights in the Santa Isabel Block in the Middle Magdalena Basin, which covers approximately 71,000 net acres. The first exploration well did not reach our planned La Luna Shale target and was expensed. Additional seismic acquisition and processing will continue in 2014. Additionally, we executed farm-in agreements to acquire 30 percent working interests in three blocks in the Middle Magdalena Basin, which cover approximately 116,000 net acres.

Venezuela

In September 2013, the World Bank's International Centre for Settlement of Investment Disputes (ICSID) arbitration tribunal ruled Venezuela unlawfully expropriated ConocoPhillips' significant oil investments in the Petrozuata and Hamaca heavy crude oil projects and the offshore Corocoro development project in June 2007. A separate arbitration phase will proceed to determine the amount of damages owed to ConocoPhillips for Venezuela's actions. For additional information, see Note 14—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Ecuador

In December 2012, an ICSID tribunal issued a decision on liability in favor of Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, 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 is now proceeding to determine the damages owed to ConocoPhillips for Ecuador's actions and to address Ecuador's counterclaims. For additional information, see Note 14—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

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 2013, operations in Canada contributed 17 percent of our worldwide liquids production and 20 percent of our natural gas production.

			2013			
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Bitumen MBD	Total MBOED
Average Daily Net Production						
Western Canada	Various %	Various	38	775	-	167
Surmont	50.0	ConocoPhillips	-	-	13	13
Foster Creek	50.0	Cenovus	-	-	50	50
Christina Lake	50.0	Cenovus	-	-	46	46
Total Canada			38	775	109	276

Western Canada
Our operations in western Canada primarily consist of three core development areas: Deep Basin, Kaybob and Clearwater, 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, 2013, held leasehold rights in 5.7 million net acres in western Canada.

Oil Sands
We hold approximately 0.9 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 peak production 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. FCCL continues to progress expansion plans which would potentially increase total gross production capacity to approximately 750 MBOED.

  - Foster Creek is located approximately 200 miles northeast of Edmonton, Alberta. There are five producing phases at Foster Creek, Phases A through E, with three more under construction: Phases F, G and H. First production for Phase F is expected in the third quarter of 2014, and first production for Phases G and H are anticipated in 2015 and 2016, respectively. These phases, in addition to planned optimization, will add approximately 125 MBOED of gross production capacity. An application for regulatory approval for an additional expansion, Phase J, was filed in 2013.

  - Christina Lake is located approximately 75 miles south of Fort McMurray, Alberta. There are five producing phases at Christina Lake, Phases A through E, with plans underway for three additional phases: Phases F, G and H. Gross production at Christina Lake increased more than 55 percent in 2013, mostly as a result of Phase D reaching full capacity in the first quarter of 2013 and Phase E commencing production in the third quarter of 2013. Phase E added 40 MBOED of gross production capacity. During 2013, construction continued on Phase F, which is expected to commence production in 2016 and add another 50 MBOED of gross production capacity. Engineering work continued for Phase G, with first production anticipated for 2017. An application for Phase H was submitted for regulatory review in 2013. With the additional expansion phases and optimization work, total gross production capacity from Christina Lake has the potential to reach approximately 310 MBOED.

- Narrows Lake is located near Christina Lake and is expected to have three phases of development. During 2013, plant construction began on Phase A, which is estimated to have 45 MBOED of gross production capacity. Initial production is anticipated in 2017.

Amauligak
We have a 55 percent operating interest in the Amauligak discovery, which lies approximately 30 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. Our primary exploration focus is on liquids-rich unconventional plays in Alberta, British Columbia and the Northwest Territories.

- *Unconventional Exploration*
  We hold approximately 0.7 million net acres in the emerging Montney, Muskwa, Duvernay and Canol unconventional plays in Alberta, northeastern British Columbia and the Northwest Territories. During 2013, we drilled unconventional test wells in the Duvernay, located in Alberta; the Canol shale, located in the Northwest Territories; and the Montney play, which extends from British Columbia into Alberta. In 2014, exploration activities will continue in Duvernay, Canol and Montney. We also plan to continue delineating potential development opportunities in the oil sands.

Asset Dispositions
During 2013, we sold our Clyden undeveloped oil sands leasehold. For additional information, see Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

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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 2013, operations in Europe contributed 14 percent of our worldwide liquids production and 11 percent of natural gas production.

Norway

			2013		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Greater Ekofisk Area	35.1 %	ConocoPhillips	54	42	61
Alvheim	20	Marathon	12	13	14
Heidrun	24	Statoil	15	14	17
Other	Various	Various	14	74	27
Total Norway			95	143	119

The Greater Ekofisk Area is located approximately 200 miles offshore Stavanger, Norway in the North Sea, and comprises four producing fields: Ekofisk, Eldfisk, Embla and Tor. Crude oil is exported to Teesside, England, and the natural gas is exported to Emden, Germany. In October 2013, we achieved first oil production from Ekofisk South, a development which includes the planned drilling of 35 new production and eight water injection wells. At year-end 2013, four production wells and the eight water injection wells had been drilled. A second development, Eldfisk II, is scheduled to start up by early 2015. Ekofisk South, along with Eldfisk II and other developments offshore Norway, are expected to add approximately 60 MBOED of net production within the next five years.

The Alvheim development is located in the northern part of the North Sea and 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 currently injected into the reservoir for optimization of crude oil production, 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, including the Aasta Hansteen development, a gas discovery with first gas scheduled for late 2017.

Exploration
During 2013, we participated in five nonoperated wells, of which three were discoveries. Also in 2013, we were awarded four new licenses in the 22nd Licencing Round in the Norwegian Barents Sea: PL718, PL720, PL723 and PL615B. We plan to participate in two nonoperated wells in the Barents Sea in 2014. In January 2014, we were awarded one operatorship and an interest in one partnership license in the Predefined Areas gas licensing round for mature areas.

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

	Interest		Operator	2013 Liquids MBD	2013 Natural Gas MMCFD	2013 Total MBOED
Average Daily Net Production						
Britannia	58.7	%	Britannia Operator Ltd.	4	96	20
Britannia Satellites	75.0-83.5		ConocoPhillips	8	21	12
J-Area	32.5-36.5		ConocoPhillips	8	49	16
Southern North Sea	Various		Various	-	93	16
East Irish Sea	100		HRL	-	14	2
Other	Various		Various	4	-	4
Total United Kingdom				24	273	70

Britannia is one of the largest natural gas and condensate fields in the North Sea. In addition to our interest in the Britannia 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. A new mono-column design compression facility for the Britannia Platform is estimated to come on line in 2014 and increase Britannia's natural gas production by approximately 90 MMCFD.

The J-Area consists of the Judy/Joanne, Jade and Jasmine fields, located in the U.K. Central North Sea. Jasmine was discovered in 2006, and first production commenced in November 2013. The Jasmine development includes a 24-slot wellhead platform with a bridge-linked accommodation and utilities platform, a six-mile, 16-inch multi-phase pipeline bundle, and a riser and processing platform bridge-linked to the existing Judy Platform. The field is a high-pressure, high-temperature gas condensate reservoir located approximately six miles west of the Judy Platform. Jasmine is estimated to achieve average net production of 30 MBOED in 2014.

We have various ownership interests in 19 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. Clair Ridge is the second phase of development for the Clair Field and is comprised of a 36-slot drilling and production facility with a bridge-linked accommodation and utilities platform. The new facilities will tie into existing oil and gas export pipelines to the Shetland Islands. Initial production for Clair Ridge is targeted for 2016.

Exploration
During 2013, we participated in two operated wells, Lacewing and Romeo, and three nonoperated wells in the Clair Field: HEXA, Segment 0 and Segment 5. The Lacewing well was deemed sub-commercial. All of the wells in the Greater Clair area were discoveries and are currently undergoing evaluation. The Romeo well is currently drilling and will be evaluated during 2014.

During 2013, we were awarded four licenses: three licenses in the Central Graben area of the North Sea, and one license in the Greater Clair area.

Transportation
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. A project to replace the Acid Gas Plant at the Rivers Gas Terminal was completed in early 2014.

Asset Dispositions
We sold our 10 percent equity interest in the Interconnector Pipeline in the first quarter of 2013.

Poland
Exploration
We are participating in a shale gas venture in Poland and own a 70 percent equity interest in Lane Energy Poland. We operate three western Baltic Basin concessions, which encompass approximately 500,000 gross acres. Four wells have been drilled on these concessions, and further well tests and drilling are planned in 2014.

Greenland
Exploration
During 2013, we were awarded one non-operated license, Block 6, in the northeast area of Greenland.

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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 2013, operations in the Asia Pacific and Middle East segment contributed 13 percent of our worldwide liquids production and 30 percent of natural gas production.

Australia and Timor Sea

			2013		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Australia Pacific LNG	37.5 %	Origin Energy	-	114	19
Bayu-Undan	56.9	ConocoPhillips	22	227	60
Athena/Perseus	50	ExxonMobil	-	35	5
Total Australia and Timor Sea			22	376	84

Australia Pacific LNG
Australia Pacific LNG Pty Ltd (APLNG), our joint venture with Origin Energy Limited and China Petrochemical Corporation (Sinopec), is focused on producing CBM from the Bowen and Surat basins in Queensland, Australia, and converting the CBM into LNG. Natural gas is currently sold to domestic customers, while progress continues on the development of the LNG processing and export sales business. Origin operates APLNG's upstream production and pipeline system, and we will operate the downstream LNG facility, located on Curtis Island near Gladstone, Queensland.

Two fully subscribed 4.5-million-tonnes-per-year LNG trains have been sanctioned. Approximately 3,900 net wells are ultimately envisioned to supply both the domestic gas market and the LNG sales contracts. The wells will be supported by gathering systems, central gas processing and compression stations, water treatment facilities, and a new export pipeline connecting the gas fields to the LNG facilities. First LNG is expected in mid-2015, under a sales agreement with Sinopec for up to 4.3 million metric tonnes of LNG per year for 20 years. Start-up of the second LNG train is expected to occur six-to-nine months following the startup of Train 1, under sales agreements with Sinopec and Japan-based Kansai Electric Power Co., Inc. The resulting LNG exports from Train 2 will commence shortly thereafter. Sinopec has agreed to purchase an additional 3.3 million metric tonnes of LNG per year through 2035, and Kansai has agreed to purchase approximately 1 million metric tonnes of LNG per year for 20 years.

In May 2012, APLNG executed project financing agreements for an $8.5 billion project finance facility and began drawing on the financing in October 2012. In connection with the execution of the project financing, we provided a completion guarantee for our pro-rata share of the project finance facility. Our guarantee of the project financing will be released upon meeting certain completion tests with milestones.

For additional information, see Note 4—Variable Interest Entities (VIEs), Note 7—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.

The Bayu-Undan natural gas recycle facility processes wet gas; separates, stores and offloads condensate, propane and butane; and re-injects dry gas back into the reservoir. In addition, a 500-kilometer natural gas pipeline connects the facility to the 3.5-million-tonnes-per-year capacity Darwin LNG Facility. Produced natural gas is piped to the Darwin LNG Plant, where it is converted into LNG before being transported to international markets. In 2013, we sold 167 billion gross cubic feet of LNG to utility customers in Japan.

The Bayu-Undan Phase Three Development was sanctioned in the third quarter of 2013, with development drilling anticipated to commence in the third quarter of 2014 and initial production estimated in the second quarter of 2015. The development will consist of two standalone, subsea horizontal wells tied back to the existing drilling, production, and processing (DPP) platform. In 2013, we secured a semi-submersible drilling rig, procured long-lead items and commenced planning and detailed engineering for subsea and DPP topsides installation. Planning and engineering activities will continue through 2014. The two wells are expected to produce over three to five years, with estimated average production of 150 MMCFD.

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. The arbitration process is currently underway. For additional information, see Note 14—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

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. In May 2013, the Timor-Leste Government referred a dispute with the Australian Government relating to the treaty on Certain Maritime Arrangements in the Timor Sea (CMATS) to international arbitration. The CMATS arbitration does not directly impact our underlying interest in Sunrise; however, key challenges must be resolved before further commercial and technical work continues.

Exploration

- *Conventional Exploration*
  We operate three permits in the Browse Basin, offshore northwest Australia. In 2013, we reduced our interests in two permits in the Greater Poseidon Area, WA-315-P and WA-398-P, from 60 percent to 40 percent. We have a 10 percent interest in WA-314-P, which is outside the Greater Poseidon Area. Phase I of the 2009/2010 Browse Basin drilling campaign resulted in discoveries in the Greater Poseidon Area: Poseidon-1, Poseidon-2 and Kronos-1. Phase II of the drilling campaign consists of six wells and commenced in 2012. The first two wells, Boreas-1 and Zephyros-1, discovered hydrocarbons and were completed, plugged and abandoned in 2012. The third well, Proteus-1, discovered hydrocarbons and was plugged and abandoned in 2013. The three wells were drilled in the Greater Poseidon Area. The fourth well, Grace-1, was drilled to satisfy a Year-5 permit obligation for WA-314-P. The Grace-1 was spud in late 2013, reached total depth in early 2014 and was declared a dry hole. The outcome does not affect our view of the overall Greater Poseidon Project.

  In the Bonaparte Basin, offshore northern Australia, we operate the NT/RL5 and NT/RL6 permits. Our ownership interest in each of the permits is 37.5 percent. A three-well appraisal program is expected to commence in 2014 to further evaluate the field’s potential.

- *Unconventional Exploration*
  In 2013, we reduced our working interest in four exploration permits within the Canning Basin of Western Australia from 75 percent to 46 percent. These permits cover approximately 11 million gross acres. Phase I of a three-well drilling program commenced in 2012 with the drilling of the Nicolay-1 and the Gibb-Maitland-1 wells. Both were written off as dry holes in 2013. Phase I drilling is expected to resume in the second half of 2014.

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Asset Dispositions
During 2013, we sold 20 percent of our working interest in the Greater Poseidon Area permits in the Browse Basin and 29 percent of our working interest in the Goldwyer Shale in the Canning Basin permits. For additional information, see Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

Indonesia

			2013		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
South Natuna Sea Block B	40.0 %	ConocoPhillips	9	107	27
South Sumatra	45.0-54.0	ConocoPhillips	2	335	58
Total Indonesia			11	442	85

We operate five production sharing contracts (PSCs) in Indonesia: the offshore South Natuna Sea Block B and four onshore PSCs, the Corridor Block and South Jambi “B”, both located in South Sumatra, Warim in Papua, and we acquired Palangkaraya in Kalimantan in 2013. 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 3 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, and liquefied petroleum gas is sold locally for domestic consumption.

South Sumatra
The Corridor PSC consists of five oil fields and seven 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. Production from the South Jambi “B” PSC has reached depletion and field development has been suspended. We are evaluating options related to the future of this PSC.

Exploration
We own and operate an 80 percent interest in the Warim onshore exploration PSC in Papua. In 2013, we signed an amendment to the PSC, which enables us to continue exploration activities for the next five years and, if there are commercial discoveries, to continue development and production activities until 2032.

In January 2013, we signed a farm-in agreement to acquire a 49 percent interest in the Palangkaraya PSC. In November 2013, we completed the acquisition of Vela Energy Limited, which increased our interest in the Palangkaraya PSC to 100 percent. The Palangkaraya PSC consists of approximately 1.9 million net acres and is located in a frontier exploration area in central Kalimantan.

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.

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China

	Interest	Operator	2013 Liquids MBD	2013 Natural Gas MMCFD	2013 Total MBOED
Average Daily Net Production					
Peng Lai	49.0 %	ConocoPhillips	40	4	41
Panyu	24.5	CNOOC	13	-	13
Total China			53	4	54

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.

Crude oil production at the Peng Lai 19-3 Field in Bohai Bay was curtailed in 2011, as a result of two separate seepage incidents which occurred near Platforms B and C. In February 2013, we received approval from China's State Oceanic Administration (SOA) to resume normal production operations.

During 2012, we reached agreements with China's Ministry of Agriculture and the SOA to resolve claims related to these seepage incidents. In the third quarter of 2013, we recognized an after-tax charge of $116 million for amounts previously paid by ConocoPhillips as operator. We do not anticipate further significant charges related to the 2011 seepage incidents.

Under the terms of the PSC, operatorship of the Peng Lai fields will transfer to our co-venturer on July 1, 2014, and we will maintain our interest as a non-operator.

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.

Exploration

- *Unconventional Exploration*
  In 2012, we entered into a joint study agreement with Sinopec Southern Exploration Company over the Qijiang shale gas block, located in the Sichuan Basin. The Qijiang Block covers approximately 1 million acres. 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.

  In February 2013, we entered into a joint study agreement with PetroChina over the 500,000-acre Neijiang-Dazu shale block, also located in the Sichuan Basin. The study is for 19 months and encompasses a desktop study and drilling preparation.

Malaysia

			2013		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Gumusut	33.0 %	Shell	6	1	6
Total Malaysia			6	1	6

We own interests in five deepwater PSCs in Malaysia. Four are located off the eastern Malaysian state of Sabah: Block G, Block J, the Kebabangan Cluster (KBBC) and SB-311. In 2013, we executed our fifth PSC, deepwater Block 3E, located off the Malaysian state of Sarawak.

Block G
We have a 21 percent interest in the unitized Siakap North-Petai oil field, which is expected to begin producing in the first quarter of 2014, with estimated net annual peak production of 6 MBOED in 2015. Development of the Malikai oil field is underway with first production anticipated in the first half of 2017. Estimated net annual peak production of 19 MBOED is expected in 2018. We own a 35 percent interest in the Malikai, Pisagan, Ubah and Limbayong oil discoveries. The Limbayong-2 appraisal well, located approximately seven miles from Gumusut, was suspended as an oil discovery in the fourth quarter of 2013.

Block J
First production for Gumusut occurred from an early production system in the fourth quarter of 2012. Production from a permanent, semi-submersible floating production vessel is expected in the second quarter of 2014, with estimated net annual peak production of 30 MBOED anticipated in 2015.

KBBC
We own a 30 percent interest in the KBBC PSC. Development of the KBB gas field commenced in 2011, with first production anticipated in late 2014. Estimated net annual peak production of 28 MBOED is expected in 2015. The Kamunsu East-2 appraisal well, located approximately seven miles northwest of the KBB gas field, was suspended as a gas discovery in the third quarter of 2013.

Exploration
We own a 40 percent operating interest in SB-311, an exploration block encompassing 259,000 acres offshore Sabah. Seismic reprocessing and acquisition occurred in 2013, and initial exploration drilling is anticipated in 2015.

In November 2013, we acquired an 85 percent operating interest in deepwater Block 3E, which encompasses approximately 480,000 acres offshore Sarawak. The PSC carries a four-year exploration term during which we plan to drill two wells.

Bangladesh
Exploration
We hold 100 percent interests in two deepwater blocks in the Bay of Bengal, Blocks 10 and 11. In 2013, we performed 2-D seismic activities and are currently evaluating the results. Additionally, we were the high bidder on adjoining Shelf Block 7 in 2013 and are awaiting finalization of the PSC.

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Brunei

Exploration

We have a 6.25 percent working interest in deepwater Block CA-2, where exploration drilling has been ongoing since September 2011. Natural gas was discovered at the Kelidang NE well and the Keratau well in 2013. We are currently evaluating the results. Additionally, the Kempas #1 well was spud in late 2013 and declared a dry hole in January 2014.

Qatar

			2013		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Qatargas 3	30.0 %	Qatargas Operating Co.	22	367	83
Total Qatar			22	367	83

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 consists of upstream natural gas production facilities, which produce approximately 1.4 billion gross cubic feet per day of natural gas from Qatar’s North Field over a 25 year life, in addition to a 7.8-million-gross-tonnes-per-year LNG facility. LNG is shipped in leased LNG carriers destined for sale globally.

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.

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OTHER INTERNATIONAL

The Other International segment includes exploration and producing operations in Libya and Russia, as well as exploration activities in Angola, Senegal and Azerbaijan. In 2013, we completed the sale of our Algeria business and the sale of our interest in the Republic of Kazakhstan's North Caspian Sea Production Sharing Agreement (Kashagan), and we have agreements to sell our Nigeria business. Accordingly, results of these operations have been reclassified to discontinued operations for all periods presented. During 2013, operations in Other International contributed 4 percent of our worldwide liquids production.

Libya

			2013		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Waha Concession	16.3 %	Waha Oil Co.	26	25	30
Total Libya			26	25	30

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 interrupted in mid-2013, as a result of the shutdown of the Es Sider crude oil export terminal at the end of July 2013. Production remains shut-in, as the Es Sider Terminal shutdown has continued into the first quarter of 2014.

Exploration
We continued to participate in the ongoing exploration and appraisal programs within the Waha Concession in 2013. We completed drilling six appraisal wells and are currently drilling four appraisal wells. During 2014, we plan to drill six additional exploration and appraisal wells.

Russia

			2013		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Polar Lights	50.0 %	Polar Lights Co.	4	-	4
Total Russia			4	-	4

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

Angola
Exploration
We have a 50 percent operating interest in Block 36 and a 30 percent operating interest in Block 37, both of which are located in Angola's subsalt play trend. The two blocks total approximately 2.5 million acres. We have secured a rig for a four-well commitment program and plan to commence drilling in the second quarter of 2014.

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Senegal
Exploration
In 2013, we farmed into three exploration blocks in offshore Senegal with a 35 percent working interest. We have secured a rig for a two-well program and expect to begin drilling in the first half of 2014.

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

Azerbaijan
Exploration
During 2013, we acquired an onshore 2-D seismic survey as part of a joint study with the State Oil Company of the Republic of Azerbaijan (SOCAR).

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.

Discontinued Operations

Nigeria

			2013		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production*					
OMLs 60, 61, 62, 63	20.0 %	Eni	12	129	34
Total Nigeria			12	129	34

**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 2013, the plant consumed 11 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.

In December 2012, we entered into agreements to sell our Nigeria business, which includes its upstream affiliates and Brass LNG. For additional information, see Note 3—Discontinued Operations, in the Notes to Consolidated Financial Statements.

Algeria
In November 2013, we sold our Algeria business. Production from discontinued operations for Algeria averaged 9 MBOED in 2013.

Kazakhstan
In October 2013, we sold our 8.4 percent interest in Kashagan.

For additional information on the Algeria and Kashagan dispositions, see Note 3—Discontinued Operations and Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

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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 primarily 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.

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 and Europe. These commodities are primarily sold under contracts with prices based on market indices, adjusted for location, quality and transportation.

Energy Partnerships
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. MWCC developed an interim containment system, which meets the U.S. Bureau of Safety and Environmental Enforcement requirements for a subsea well containment system that can respond to a deepwater well control incident in the U.S. Gulf of Mexico. To advance this capability, MWCC continues to develop an expanded containment system with significantly increased capacity. The expanded containment system should be available by the end of 2014.

Subsea Well Response Project
In 2011, we, along with several leading oil and gas companies, launched the Subsea Well Response Project (SWRP), a non-profit organization based in Stavanger, Norway, which was created to enhance the industry’s capability to respond to international subsea well control incidents. Through collaboration with Oil Spill Response Limited, a non-profit organization in the United Kingdom, subsea well intervention equipment is available for the industry to use in the event of a subsea well incident. This complements the work being undertaken in the United States by MWCC.

Technology
Our Technology organization has several technology programs, which focus on areas to support our business growth plans: developing unconventional reservoirs, producing oil sands and heavy oil economically with fewer emissions, advancing our competitiveness in deepwater development capabilities, improving the economic efficiency of our LNG and other gas solutions technologies, increasing recoveries from our legacy fields, and implementing sustainability measures.

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 12 more under construction and several feasibility studies ongoing.

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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, 2013. No difference exists between our estimated total proved reserves for year-end 2012 and year-end 2011, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2013.

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 200 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 any 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 statistics published in the September 2, 2013, issue of the *Oil and Gas Journal*, we had the third-largest worldwide liquids and natural gas reserves for U.S.-based oil and gas companies in 2012. 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 safely operating oil and gas producing properties.

GENERAL

At the end of 2013, we held a total of 811 active patents in 55 countries worldwide, including 336 active U.S. patents. During 2013, we received 40 patents in the United States and 50 foreign patents. Our products and processes generated licensing revenues of $128 million in 2013. 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 $258 million, $221 million and $193 million in 2013, 2012 and 2011, respectively.

Health, Safety and Environment

Our Health, Safety and Environment (HSE) organization provides tools and support to our business units and staff groups to help them ensure world class health, safety and environmental performance. The framework through which we safely manage our operations, the HSE Management System Standard, emphasizes process safety, risk management, emergency preparedness and environmental performance, with an intense focus on occupational safety. In support of the goal of zero incidents, our HSE Excellence Process requires the business units to measure performance and drive continuous improvement. Assessments are conducted annually to capture progress and set new targets. We also have detailed processes in place to address sustainable development in our economic, environmental and social performance. Our processes, related tools and requirements focus on water, biodiversity and climate change, as well as social and stakeholder issues.

The environmental information contained in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 63 through 66 under the captions "Environmental" and "Climate Change" is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2013 and those expected for 2014 and 2015.

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, optimize production performance or 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 by our personnel. 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 significant future price changes could have a material effect on the quantity and present value of our proved reserves. 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 and greenhouse gas emissions.
- Carbon taxes.
- The handling, use, storage, transportation, disposal and cleanup of hazardous materials and hazardous and nonhazardous wastes.

- The dismantlement, abandonment and restoration of our properties and facilities at the end of their useful lives.
- Exploration and production activities in certain areas, such as offshore environments, arctic fields, oil sands reservoirs and shale 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. U.S. federal, state and local legislative and regulatory agencies' initiatives regarding the hydraulic fracturing process could result in operating restrictions or delays in the completion of our oil and gas wells.

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. Changes in domestic and international regulations may affect our ability to obtain or maintain permits, including those necessary for drilling and development of wells or for construction of LNG terminals or regasification facilities in various locations.

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 54 percent of our hydrocarbon production from continuing operations was derived from production outside the United States in 2013, and 56 percent of our proved reserves, as of December 31, 2013, 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, bitumen, natural gas liquids 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.

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

We conduct many of our operations through joint ventures in which we may share control with our joint venture partners. 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 partners 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, crude oil spills, severe weather, geological events, labor disputes, civil unrest or cyber attacks. Our operations may be adversely affected by unavailability, interruptions or accidents involving infrastructure required to process or transport our production, such as pipelines, railcars, tankers, barges or other infrastructure. Our operations are also subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks. Activities in deepwater areas may pose incrementally greater risks because of complex subsurface conditions such as higher reservoir pressures, water depths and metocean conditions. 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 have 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.

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 2013, as well as matters previously reported in our 2012 Form 10-K and our first-, second- and third-quarter 2013 Form 10-Qs that were not resolved prior to the fourth quarter of 2013. 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 were to be decided adversely to ConocoPhillips, we expect there would be no material effect on our consolidated financial position. Nevertheless, such proceedings are reported pursuant to the SEC regulations.

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.

Matters Previously Reported – ConocoPhillips
The New Mexico Environment Department has issued 4 Notices of Violation (NOVs) to ConocoPhillips alleging a total of 16 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 are working with the agency to resolve these matters.

Matters Previously Reported – Phillips 66
In October 2007, ConocoPhillips 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.

On May 19, 2010, the Phillips 66 Lake Charles 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.

In October 2011, ConocoPhillips was notified by the Attorney General of the State of California that 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, the California Attorney General filed a lawsuit notice that alleges such violations.

On March 7, 2012, the Bay Area Air Quality Management District (District) in California issued a $302,500 demand to settle five NOVs issued between 2008 and 2010. The NOVs allege non-compliance with the District rules and/or facility permit conditions at the Phillips 66 Rodeo Refinery.

On September 19, 2012, the District issued a $213,500 demand to settle 14 NOVs issued in 2009 and 2010 with respect to alleged violations of regulatory and/or permit requirements at the Phillips 66 Rodeo Refinery.

On October 15, 2012, the District issued a $313,000 demand to settle 13 other NOVs issued in 2010 and 2011 with respect to alleged violations of regulatory and/or permit requirements at the Phillips 66 Rodeo Refinery.

In May 2012, the Illinois Attorney General’s office filed and notified ConocoPhillips of a complaint 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.

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	57
Sheila Feldman	Vice President, Human Resources	59
Matt J. Fox	Executive Vice President, Exploration and Production	53
Alan J. Hirshberg	Executive Vice President, Technology and Projects	52
Janet L. Kelly	Senior Vice President, Legal, General Counsel and Corporate Secretary	56
Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer	51
Andrew D. Lundquist	Senior Vice President, Government Affairs	53
Glenda M. Schwarz	Vice President and Controller	48
Jeff W. Sheets	Executive Vice President, Finance and Chief Financial Officer	56
Don E. Wallette, Jr.	Executive Vice President, Commercial, Business Development and Corporate Planning	55

**On February 15, 2014.*

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 13, 2014. 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; and Vice President, Worldwide Deepwater Projects from 2008 to 2009.

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.

Andrew D. Lundquist was appointed Senior Vice President, Government Affairs in 2013. Prior to that, he served as managing partner of BlueWater Strategies LLC, since 2002.

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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.

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.

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
2013			
First	**$ 62.05**	**56.78**	**0.66**
Second	**64.77**	**56.38**	**0.66**
Third	**71.09**	**60.73**	**0.69**
Fourth	**74.59**	**68.23**	**0.69**
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

Closing Stock Price at December 31, 2013	$ 70.65
Closing Stock Price at January 31, 2014	$ 64.95
Number of Stockholders of Record at January 31, 2014*	54,896

**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

Our share repurchase program announced on December 2, 2011, to repurchase up to $10 billion of common stock expired on December 2, 2013. Approximately $5.1 billion of shares were repurchased under the program since its inception.

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Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2013	2012	2011	2010	2009
Sales and other operating revenues	$ **54,413**	57,967	64,196	56,215	47,879
Income from continuing operations	**8,037**	7,481	7,188	10,305	3,737
Per common share					
Basic	**6.47**	5.95	5.18	6.93	2.46
Diluted	**6.43**	5.91	5.14	6.88	2.44
Income from discontinued operations	**1,178**	1,017	5,314	1,112	755
Net income	**9,215**	8,498	12,502	11,417	4,492
Net income attributable to ConocoPhillips	**9,156**	8,428	12,436	11,358	4,414
Per common share					
Basic	**7.43**	6.77	9.04	7.68	2.96
Diluted	**7.38**	6.72	8.97	7.62	2.94
Total assets	**118,057**	117,144	153,230	156,314	152,138
Long-term debt	**21,073**	20,770	21,610	22,656	26,925
Joint venture acquisition obligation—long-term	**-**	2,810	3,582	4,314	5,009
Cash dividends declared per common share	**2.70**	2.64	2.64	2.15	1.91

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

- Net income and Net income attributable to ConocoPhillips for all periods presented includes income from discontinued operations as a result of the separation of the Downstream business, the sale of our interest in Kashagan, the sale of our Algeria business, and the intention to sell our Nigeria business. Total assets for 2011 and prior years includes assets for the Downstream business. For additional information, see Note 3—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.

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

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," "seek," "should," "will," "would," "expect," "objective," "projection," "forecast," "goal," "guidance," "outlook," "effort," "target" and similar expressions identify forward-looking statements. The Company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the Company's disclosures under the heading: "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 71.

Due to discontinued operations reporting, as more fully described below, income (loss) from continuing operations is more representative of ConocoPhillips' earnings. 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 27 countries. At December 31, 2013, we had approximately 18,400 employees worldwide and total assets of $118 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 asset disposition program, in the fourth quarter of 2013, we completed the sale of our interest in the North Caspian Sea Production Sharing Agreement (Kashagan) and the sale of our Algeria business, and we have agreements to sell our Nigeria business. Results of operations related to Phillips 66, Kashagan, Algeria and Nigeria have been classified as discontinued operations in all periods presented in this Annual Report on Form 10-K. For additional information, see Note 3—Discontinued Operations, in the Notes to Consolidated Financial Statements.

Overview

We are an independent E&P company focused on exploring for, developing and producing crude oil and natural gas globally. Our asset base reflects our legacy as a major company with a strategic focus on higher-margin developments. Our diverse portfolio includes resource-rich North American shale and oil sands assets; lower-risk legacy assets in North America, Europe, Asia and Australia; several major international developments; and a growing inventory of global conventional and unconventional exploration prospects. Our value proposition to our shareholders is to deliver 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 this value proposition through optimizing our portfolio, investing in high-margin developments, applying technical capability and maintaining financial flexibility.

We achieved several strategic milestones in 2013. We delivered on our non-core asset sales, advanced our growth programs, achieved exploration success and increased shareholder distributions. These accomplishments will position us to meet our goal of 3 to 5 percent annual production and margin growth beginning in 2014.

During 2013, we generated $15.8 billion in cash from continuing operations, paid dividends on our common stock of $3.3 billion and generated $10.2 billion in proceeds from dispositions of non-core assets. This brings the total proceeds received to $12.4 billion for the 2012–2013 program, which has exceeded our goal of raising $8–$10 billion in proceeds from disposition of non-strategic assets during 2012 and 2013. Consistent with our commitment to offer our shareholders a compelling dividend, in July 2013, our Board of Directors increased our quarterly dividend by 4.5 percent to $0.69 per share.

In 2013, we achieved production of 1,545 thousand barrels of oil equivalent per day (MBOED), including production from discontinued operations of 43 MBOED. With the startup of major projects at Christina Lake Phase E, Ekofisk South and Jasmine in 2013, final preparations underway for full-field startup at Gumusut and Siakap North-Petai, and a portfolio of high-margin opportunities, we have the momentum to begin delivering our volume growth goals in 2014.

We funded a $16.9 billion capital program in 2013 and fully prepaid a $2.8 billion joint venture acquisition obligation to our 50 percent owned FCCL Partnership. Our 2013 capital program yielded a strong organic reserve replacement, as our annual organic reserve replacement ratio was 179 percent. The organic reserve additions represent a continuing portfolio shift to higher-value liquids and reflect increased levels of activity in our development programs and major projects.

Our 2014 capital budget of $16.7 billion will target our diverse portfolio of global opportunities, with approximately 55 percent of the budget allocated toward North America and 45 percent toward Europe, Asia Pacific and other international businesses. Our investments will be directed predominantly toward high-quality developments already underway in the United States, Canada, the United Kingdom, the Norwegian North Sea, Malaysia and Australia, as well as exploration opportunities which will continue to build our inventory for the future.

Key Operating and Financial Highlights

Significant highlights during 2013 included the following:

- Achieved annual organic reserve replacement of 179 percent from reserve additions of approximately 1.1 billion barrels of oil equivalent.
- Achieved annual production of 1,545 MBOED, including continuing operations of 1,502 MBOED and discontinued operations of 43 MBOED, and generated earnings of $8.0 billion.
- Increased quarterly dividend by 4.5 percent.
- Generated $10.2 billion in proceeds from asset dispositions.
- Announced two deepwater Gulf of Mexico discoveries at Coronado and Gila, adding to the existing Shenandoah and Tiber discoveries in 2009.
- Eagle Ford and Bakken production increased 60 percent in 2013 compared with 2012.
- Commenced production from major projects at Christina Lake Phase E, Ekofisk South and Jasmine, with preparations underway for full-field startup at Gumusut and Siakap North-Petai in 2014.

Business Environment

The business environment for the energy industry has historically experienced many challenges which have influenced our operations and profitability, largely due to factors beyond our control, such as the global financial crisis and recession which began in 2008; supply disruptions or fears thereof caused by civil unrest or military conflicts; environmental laws; tax regulations; governmental policies; and weather-related disruptions. Recently, North America’s energy landscape has been transformed from resource scarcity to an abundance of supply, as a result of advances in technology responsible for the rapid growth of shale production, successful exploration and development in the deepwater Gulf of Mexico and rising production from the Canadian oil sands. These dynamics generally influence world energy markets and commodity prices. The most significant factor impacting our profitability and related reinvestment of our operating cash flows into our business is commodity prices, which can be very volatile; therefore, our strategy is to maintain a strong balance sheet with a diverse portfolio of assets, which we believe will provide the financial flexibility to withstand challenging business cycles.

Operating and Financial Priorities
Important factors we must continue to manage well in order to be successful include:

- Maintaining a relentless focus on safety and environmental stewardship. Safety and environmental stewardship, including the operating integrity of our assets, remain our highest priorities, 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. Our sustainability efforts in 2013 focused on updating action plans for climate change, biodiversity, water and human rights, as well as revamping public reporting to be more informative, searchable and responsive to common questions.

  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. We are a founding member of the Marine Well Containment Company LLC (MWCC), a non-profit organization formed in 2010 to improve industry spill response in the U.S. Gulf of Mexico. MWCC developed a containment system, which meets the U.S. Bureau of Safety and Environmental Enforcement requirements for a subsea well containment system that can respond to a deepwater well control incident in the U.S. Gulf of Mexico. To complement this work internationally, we and several leading oil and gas companies established the Subsea Well Response Project in Norway, which enhances the oil industry’s ability to respond to subsea well-control incidents in international waters.

- 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 adding to our proved reserve base, and we anticipate being able to do so in the future. In the five years ended December 31, 2013, our organic reserve replacement was 145 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 invest significant capital dollars to explore for new oil and gas fields, develop newly discovered fields, maintain existing fields, and construct pipelines and liquefied natural gas (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 organic growth in volumes and margins through higher-margin oil, condensate and LNG projects 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 decision to the time the asset is operational and generates financial returns.

Our actual capital program for 2013 was $16.9 billion, excluding a $2.8 billion prepayment to FCCL for the remaining balance of our joint venture acquisition obligation. Our capital budget for 2014 is $16.7 billion. Approximately 13 percent of the 2014 capital budget is allocated toward maintenance of our legacy base portfolio, including planned turnarounds; 39 percent is allocated to high-margin development drilling programs, mostly in North America, which is intended to offset natural field decline from our producing assets; 35 percent is focused on sanctioned major developments, such as Australia Pacific LNG (APLNG) and Surmont Phase 2; and 13 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 $8–$10 billion of noncore assets through the end of 2013. During 2013, we received proceeds from dispositions of approximately $10.2 billion, which primarily resulted from:

  - The disposition of our 8.4 percent interest in Kashagan, located in Kazakhstan.
  - The sale of our Algeria business.
  - The sale of the majority of our producing zones in the Cedar Creek Anticline, located in North Dakota and Montana.
  - The sale of our Clyden undeveloped oil sands leasehold, located in Canada.
  - The disposition of our 39 percent equity investment in Phoenix Park Gas Processors Limited, located in Trinidad and Tobago.
  - The disposition of a portion of our working interests in the Poseidon discovery in the Browse Basin and the Goldwyer Shale in the Canning Basin.
  - The disposition of certain properties located in southwest Louisiana.
  - The sale of our 10 percent interest in the Interconnector Pipeline, located in Europe.

  As previously announced, we entered into agreements to sell our Nigeria business, which includes its upstream affiliates and Brass LNG. The upstream sale is anticipated to close in the first quarter of 2014 and generate proceeds of approximately $1.5 billion, after customary adjustments. We have received deposits to date of $500 million, with the remainder of approximately $1.0 billion due at closing. The buyer has until March 31, 2014, to close on Brass LNG. The sale of Brass LNG would generate proceeds of approximately $0.16 billion, after customary adjustments.

  During 2012, we received proceeds of $2.1 billion from the sale of our Vietnam business, the Statfjord and Alba fields in the North Sea, our investment in Naryanmarneftegaz (NMNG) in Russia, and the additional dilution of our interest in APLNG from 42.5 percent to 37.5 percent.

  Although we are near completion of the 2012–2013 asset disposition program, we will continue to evaluate our assets to determine whether they fit our strategic direction. We will prune the portfolio as necessary and direct our capital investments to areas which will achieve our strategic objectives.

- 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. As 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 4 percent in 2013 compared with 2012, primarily as a result of higher operating expenses in the Lower 48 associated with increased production.

- Applying technical capability. We focus on ways to leverage our knowledge and technology to create value and safely deliver on our plans. Technical strength is part of our heritage, and we are evolving our technical approach to optimally apply best practices where they matter most. In 2013, we tested new technology as a means to provide remote monitoring capability, as well as new methods that could increase production and reduce water usage and emissions from assets, such as the oil sands and unconventional reservoirs. Companywide, we continue to evaluate potential solutions to leverage knowledge of technological successes across all of our operations. Such innovations enable us to economically convert additional resources to reserves, achieve greater operating efficiencies and reduce our environmental impact.

- 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. As part of our future workforce planning, we are committed to increasing student interest in energy industry professions by awarding scholarships in science, technology, engineering, mathematics, accounting and finance, as well as providing university internships to attract the best talent. We also recruit experienced hires to maintain a broad range of skills and experience. Career development is an important investment in our employees and our future, so we focus on continued learning, development and technical training through structured development programs designed to accelerate technical and functional skills of our employees.

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		
	2013	2012	2011
Market Indicators			
WTI (per barrel)	**$ 97.90**	94.16	95.05
Dated Brent (per barrel)	**108.65**	111.58	111.27
U.S. Henry Hub first of month (per million British thermal units)	**3.65**	2.79	4.04

Brent crude oil prices decreased 3 percent in 2013, compared with 2012, to average $108.65 per barrel, as disruptions to the Organization of Petroleum Exporting Countries (OPEC) supplies were more than offset by non-OPEC production growth. Global oil demand grew 1 percent, or about 1.2 million barrels per day, to 91.2 million barrels per day. The fiscal uncertainties that plagued many developed countries, while not completely resolved, subsided enough to help restore confidence and growth in real economic activity in 2013.

WTI crude oil prices increased 4 percent in 2013, compared with 2012, as new infrastructure helped to alleviate the glut at Cushing, Oklahoma, by increasing the movement of physical barrels toward U.S. Gulf Coast refining centers. As a result, the WTI discount to Brent decreased by 38 percent to average $10.75. U.S. crude oil production grew 16 percent to reach an average of 7.5 million barrels per day. The growth was led by shale oil developments such as Bakken, Eagle Ford and Permian. U.S. oil demand increased by 2 percent in 2013, as economic growth strengthened.

Henry Hub natural gas prices increased 31 percent in 2013 compared with 2012. Strong weather-driven demand growth outweighed production growth and drew down high storage inventories. U.S. natural gas consumption rose 2 percent, or 1.5 billion cubic feet per day, to an all-time high of

71.2 billion cubic feet per day. U.S. dry gas production increased 1 percent, by 0.8 billion cubic feet per day, to reach 66.5 billion cubic feet per day, as growth from the Marcellus shale gas play more than offset declines in other areas.

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 11 percent in 2013 compared with 2012. Our realized bitumen price remained relatively flat in 2013.

In recent years, the use of hydraulic fracturing and horizontal drilling in shale natural gas formations has led to increased industry actual and forecasted natural gas production in the United States. Although providing significant short- and long-term 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; 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 2013 totaled $0.5 billion and mainly resulted from impairments of various properties in Europe, which have ceased production or are nearing the end of their useful lives, and mature natural gas properties in Canada. 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. 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 have been suspended since July 2013 due to the closure of the Es Sider crude oil export terminal, and they were also suspended in 2011 during Libya’s period of civil unrest. In the United Kingdom, the government enacted tax legislation in both 2012 and 2011, which increased our U.K. corporate tax rate. Our assets in Venezuela and Ecuador were expropriated in 2007 and 2009, respectively. Our management carefully considers these events when evaluating projects or determining the level of activity in such countries.

Outlook

Due to the ongoing shutdown of the Es Sider Terminal in Libya, we intend to exclude Libya from our future production outlooks. Production from continuing operations for 2013 was 1,502 MBOED, or 1,472 MBOED adjusted for Libya. Full-year 2014 production from continuing operations is expected to be approximately 1,550 MBOED, excluding Libya. First-quarter 2014 production from continuing operations is expected to be 1,490 to 1,530 MBOED, excluding Libya. Our Corporate and Other segment earnings are expected to be an after-tax loss of approximately $1.0 billion for the full-year 2014.

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. In July 2013, we agreed with Freeport LNG to terminate this agreement, subject to Freeport LNG obtaining regulatory approval and project financing for an LNG liquefaction and export facility in Texas, in which we are not a participant. Upon satisfaction of these conditions, currently expected to occur in the second half of 2014, we will pay Freeport LNG a termination fee of approximately $600 million. Freeport LNG will repay the outstanding ConocoPhillips loan used by Freeport LNG to partially fund the original construction of the terminal. These transactions, plus miscellaneous items, will result in a one-time net cash outflow of approximately $80 million for us. When the agreement becomes effective, we also expect to recognize an after-tax charge to earnings of approximately $540 million. At that time, our terminal regasification capacity will be reduced from 0.9 billion cubic feet per day to 0.4 billion cubic feet per day, until July 1, 2016, at which time it will be reduced to zero. As a result of this transaction, we anticipate saving approximately $50 to $60 million per year in operating costs over the next 19 years. For additional information, see Note 4—Variable Interest Entities (VIEs), in the Notes to Consolidated Financial Statements.

Operating Segments

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 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	**2013**	2012	2011
Alaska	$ **2,274**	2,276	1,984
Lower 48 and Latin America	**1,081**	1,029	1,288
Canada	**718**	(684)	91
Europe	**1,199**	1,498	1,830
Asia Pacific and Middle East	**3,591**	3,996	3,093
Other International	**(6)**	359	(377)
LUKOIL Investment	**-**	-	239
Corporate and Other	**(820)**	(993)	(960)
Income from continuing operations	$ **8,037**	7,481	7,188

2013 vs. 2012

Earnings for ConocoPhillips increased 7 percent in 2013. The increase was mainly due to:

- Lower impairments. Non-cash impairments in 2013 totaled $289 million after-tax, compared with $900 million after-tax in 2012.
- Higher natural gas prices.
- A higher proportion of production in higher-margin areas and a continued portfolio shift toward liquids.
- Lower production taxes, primarily as a result of lower production volumes and prices, and higher capital spending in Alaska.

These items were partially offset by:

- Higher depreciation, depletion and amortization (DD&A) expenses, mainly due to higher volumes in the Lower 48 and China.
- Lower gains from asset sales. In 2013, gains from asset dispositions were $1,132 million after-tax, compared with gains of $1,567 million after-tax in 2012.
- Higher operating expenses.
- Lower crude oil and natural gas liquids prices.

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.

Income Statement Analysis

2013 vs. 2012

Sales and other operating revenues decreased 6 percent in 2013, mainly due to lower natural gas volumes and lower crude oil prices, partly offset by higher natural gas prices.

Equity in earnings of affiliates increased 16 percent in 2013. The increase primarily resulted from higher earnings from FCCL Partnership, mainly as a result of higher bitumen volumes.

Gain on dispositions decreased 25 percent in 2013. For additional information, see Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

Other income decreased 20 percent in 2013, primarily due to the absence of the 2012 benefit which resulted from the favorable resolution of the Petróleos de Venezuela S.A. (PDVSA) International Chamber of Commerce (ICC) arbitration. The decrease was partly offset by a $150 million insurance settlement in 2013 associated with the Bohai Bay seepage incidents. For information on a separate PDVSA arbitration with the World Bank's International Centre for Settlement of Investment Disputes (ICSID), see Note 14—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Purchased commodities decreased 10 percent in 2013, largely as a result of lower purchased natural gas volumes, partly offset by higher natural gas prices.

Production and operating expenses increased 7 percent in 2013, primarily due to increased drilling activity and production volumes, mostly in the Lower 48, in addition to a charge related to a settlement in Asia Pacific and Middle East. These increases were partly offset by the reduction of an accrual related to the Federal Energy Regulatory Commission (FERC) approval of cost allocation (pooling) agreements with the remaining owners of the Trans-Alaska Pipeline System (TAPS).

SG&A expenses decreased 23 percent in 2013, primarily due to the absence of separation costs, lower pension settlement expense and lower costs related to compensation and benefit plans. For additional information on pension settlement expense, see Note 19—Employee Benefit Plans, in the Notes to Consolidated Financial Statements.

Exploration expenses decreased 18 percent in 2013, largely due to lower leasehold impairment costs. Exploration costs in 2012 included the $481 million impairment of undeveloped leasehold costs associated with the Mackenzie Gas Project, as a result of the indefinite suspension of the project. Increased 2013 exploration activity and higher dry hole costs, mostly in the Lower 48, partly offset the reduction.

DD&A increased 13 percent in 2013. The increase was mostly associated with higher production volumes in the Lower 48. Higher production volumes in China partly contributed to the increase.

Impairments decreased 22 percent in 2013. Impairments in 2013 mainly consisted of increases in the asset retirement obligation (ARO) for properties located in the United Kingdom, which have ceased production or are nearing the end of their useful lives, and mature natural gas properties in Canada. Impairments in 2012 consisted of impairments of capitalized development costs associated with the Mackenzie Gas Project, the disposition of Cedar Creek Anticline and impairments of late-life U.K. properties. For additional information, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Taxes other than income taxes decreased 19 percent in 2013, mainly due to lower production taxes as a result of lower crude oil production volumes and prices, and higher capital spending in Alaska.

Interest and debt expense decreased 14 percent in 2013, mostly as a result of lower interest expense from 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.

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 and the Statfjord and Alba fields in the North Sea, 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.

Other income increased 78 percent in 2012, mostly as a result of the favorable resolution of the PDVSA ICC arbitration.

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 Mackenzie Gas Project impairment.

Impairments increased 112 percent in 2012. Impairments in 2012 included the impairment of capitalized development costs associated with the Mackenzie Gas Project, the disposition of Cedar Creek Anticline, and impairments of various late-life properties, mostly located in the United Kingdom. Impairments in 2011 consisted of various North American natural gas properties.

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.

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Summary Operating Statistics

		2013	2012	2011
Average Net Production				
Crude oil (MBD)*		**581**	595	622
Natural gas liquids (MBD)		**156**	156	145
Bitumen (MBD)		**109**	93	67
Natural gas (MMCFD)**		**3,939**	4,096	4,359
Total Production (MBOED)***		**1,502**	1,527	1,561
		Dollars Per Unit		
Average Sales Prices				
Crude oil (per barrel)	$	**103.32**	105.72	105.52
Natural gas liquids (per barrel)		**41.42**	46.36	55.73
Bitumen (per barrel)		**53.27**	53.91	62.56
Natural gas (per thousand cubic feet)		**6.11**	5.48	5.80
		Millions of Dollars		
Worldwide Exploration Expenses				
General and administrative; geological and geophysical; and lease rentals	$	**789**	626	569
Leasehold impairment		**175**	719	159
Dry holes		**268**	155	310
	$	**1,232**	1,500	1,038

Excludes discontinued operations.
**Thousands of barrels per day.*
***Millions of cubic feet per day. Represents quantities available for sale and excludes gas equivalent of natural gas liquids included above.*
****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, 2013, our continuing operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, Qatar, Libya and Russia.

In 2013, average production from continuing operations decreased 2 percent compared with 2012, mainly due to normal field decline, asset dispositions, shut-in Libya production, due to the closure of the Es Sider crude oil export terminal, and higher unplanned downtime. These decreases were partially offset by new production from major developments, mainly from shale plays in the Lower 48, the ramp-up of production from new phases at Christina Lake in Canada, and early production in Malaysia; higher production in China; and increased conventional drilling and well performance, mostly in the Lower 48, western Canada and Norway. Adjusted for dispositions, downtime and the impact from the closure of the Es Sider Terminal in Libya, production grew by 30 MBOED, or 2 percent, compared with 2012.

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.

Alaska

		2013	2012	2011
Income from Continuing Operations (millions of dollars)	$	**2,274**	2,276	1,984
Average Net Production				
Crude oil (MBD)		**178**	188	200
Natural gas liquids (MBD)		**15**	16	15
Natural gas (MMCFD)		**43**	55	61
Total Production (MBOED)		**200**	213	225
Average Sales Prices				
Crude oil (per barrel)	$	**107.83**	109.62	105.95
Natural gas (per thousand cubic feet)		**4.35**	4.22	4.56

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas liquids, natural gas and LNG. In 2013, Alaska contributed 23 percent of our worldwide liquids production and 1 percent of our natural gas production.

2013 vs. 2012

Alaska earnings in 2013 were flat compared with 2012 earnings. Earnings in 2013 were mainly impacted by lower crude oil volumes and lower crude oil prices. These decreases to earnings were mostly offset by lower production taxes, which resulted from lower prices, higher 2013 capital spending and lower crude oil production volumes. Additionally, 2013 earnings benefitted from the impact of a ruling by the FERC.

In 2012, the major owners of TAPS filed a proposed settlement with FERC to resolve pooling disputes prior to August 2012 and establish a voluntary pooling agreement to pool costs prospectively from August 2012. In July 2013, the FERC approved the proposed settlement and pooling agreement without modification. Under the terms of the agreements, we paid the other remaining owners of TAPS $355 million, including interest, in the third quarter of 2013. As a result of FERC approval of these agreements, we reduced a related accrual in the second quarter of 2013, which decreased our production and operating expenses by $97 million after-tax. The FERC ruling approving these agreements has been appealed by certain parties to the Court of Appeals for the District of Columbia.

Production averaged 200 MBOED in 2013, a decrease of 6 percent compared with 2012. This decrease was mainly due to normal field decline, partially offset by lower planned downtime.

2012 vs. 2011

Alaska earnings in 2012 increased 15 percent compared with earnings 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.

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Lower 48 and Latin America

		2013	2012	2011
Income from Continuing Operations (millions of dollars)	$	**1,081**	1,029	1,288
Average Net Production				
Crude oil (MBD)		**152**	123	94
Natural gas liquids (MBD)		**91**	85	74
Natural gas (MMCFD)		**1,490**	1,493	1,556
Total Production (MBOED)		**491**	457	428
Average Sales Prices				
Crude oil (per barrel)	$	**93.79**	91.67	92.79
Natural gas liquids (per barrel)		**31.48**	35.45	50.55
Natural gas (per thousand cubic feet)		**3.50**	2.67	3.99

During 2013, Lower 48 and Latin America contributed 29 percent of our worldwide liquids production and 38 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, as well as exploration activities in the Gulf of Mexico and Colombia.

2013 vs. 2012

Lower 48 and Latin America earnings increased 5 percent in 2013 compared with 2012. Earnings in 2013 largely benefitted from higher crude oil and NGL volumes, higher gains from asset dispositions, mostly as a result of the $288 million after-tax gain on disposition of our equity investment in Phoenix Park, higher natural gas and crude oil prices and lower impairments. These increases were partially offset by higher DD&A, as a result of higher crude oil production, as well as the absence of the 2012 realization of a tax loss carryforward of $236 million and the 2012 favorable resolution of the PDVSA ICC arbitration, as more fully described below. Higher operating expenses, higher exploration expenses, which mainly resulted from the Thorn and Ardennes dry holes in the Gulf of Mexico, and lower NGL prices also partially offset the increase in 2013 earnings. For additional information on asset sales, see Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

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 was reflected in the Corporate and Other segment. For information on a separate PDVSA ICSID arbitration, see Note 14—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Average production in the Lower 48 increased 7 percent in 2013, while average crude oil production increased 24 percent in the same period. New production, primarily from the Eagle Ford and Bakken areas, and improved drilling and well performance more than offset normal field decline and the impact from dispositions.

2012 vs. 2011

Lower 48 and Latin America earnings decreased 20 percent in 2012 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

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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.

Average production increased 7 percent in 2012, while average crude oil production increased 31 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.

Canada

		2013	2012	2011
Income (Loss) from Continuing Operations (millions of dollars)	$	**718**	(684)	91
Average Net Production				
Crude oil (MBD)		**13**	13	12
Natural gas liquids (MBD)		**25**	24	26
Bitumen (MBD)				
Consolidated operations		**13**	12	10
Equity affiliates		**96**	81	57
Total bitumen		**109**	93	67
Natural gas (MMCFD)		**775**	857	928
Total Production (MBOED)		**276**	273	260
Average Sales Prices				
Crude oil (per barrel)	$	**79.73**	78.26	86.04
Natural gas liquids (per barrel)		**47.19**	48.64	56.84
Bitumen (dollars per barrel)				
Consolidated operations		**55.25**	57.58	55.16
Equity affiliates		**53.00**	53.39	63.93
Total bitumen		**53.27**	53.91	62.56
Natural gas (per thousand cubic feet)		**2.92**	2.13	3.46

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 2013, Canada contributed 17 percent of our worldwide liquids production and 20 percent of our natural gas production.

2013 vs. 2012

Canada operations reported earnings of $718 million in 2013, an increase of $1,402 million, compared with a loss of $684 million in 2012. The increase in 2013 earnings was largely due to:

- The $461 million after-tax gain on disposition of our Clyden undeveloped oil sands leasehold.
- Lower impairments. Impairments in 2013 consisted of the $162 million after-tax impairment of mature natural gas assets in western Canada. Impairments in 2012 mainly resulted from the $520 million after-tax impairment of the Mackenzie Gas Project and associated undeveloped leaseholds.
- Higher bitumen volumes, primarily at Christina Lake.
- The recognition of additional income of $224 million related to the favorable tax resolution associated with the sale of certain western Canada properties in a prior year.

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For additional information on asset sales, see Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements. For additional information on impairments, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Average production in Canada increased 1 percent in 2013, while average liquids production increased 13 percent in the same period, primarily from the oil sands. Normal field decline was more than offset by the ramp-up of production from Christina Lake Phases D and E in FCCL and improved drilling and well performance from western Canada.

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 Mackenzie Gas Project impairment 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 in FCCL.

Europe

		2013	2012	2011
Income from Continuing Operations (millions of dollars)	$	**1,199**	1,498	1,830
Average Net Production				
Crude oil (MBD)		**113**	135	164
Natural gas liquids (MBD)		**6**	7	11
Natural gas (MMCFD)		**416**	516	626
Total Production (MBOED)		**189**	228	279
Average Sales Prices				
Crude oil (dollars per barrel)	$	**110.56**	113.08	111.82
Natural gas liquids (per barrel)		**58.36**	61.53	59.19
Natural gas (per thousand cubic feet)		**10.68**	9.76	9.26

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 2013, our Europe operations contributed 14 percent of our worldwide liquids production and 11 percent of our natural gas production.

2013 vs. 2012

Europe operations reported a 20 percent decrease in 2013 earnings compared with 2012, primarily due to lower volumes and lower gains from asset dispositions. Gains realized in 2012 included the $287 million after-tax gain on sale of our interests in the Statfjord and Alba fields, compared with the $83 million after-tax gain on sale of our interest in the Interconnector Pipeline in 2013. These decreases were partly offset by the absence of the recognition of $170 million in additional income tax expense in 2012, as a result of legislation enacted in the United Kingdom, which restricted corporate tax relief on decommissioning costs to 50 percent. The additional tax expense resulted from the revaluation of deferred tax balances.

Average production decreased 17 percent in 2013, primarily due to normal field decline. Major planned maintenance at Greater Ekofisk, higher unplanned downtime, mostly in the East Irish Sea, and asset dispositions also contributed to the decrease. These decreases were partially offset by improved drilling and well performance in Norway and new production from Jasmine and Ekofisk South.

2012 vs. 2011

Earnings from Europe decreased 18 percent in 2012 compared with 2011, mainly as a result of lower volumes, higher impairments and the U.K. tax increase. These decreases to earnings were partly offset by the gain on disposition of Statfjord and Alba 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 decreased 18 percent in 2012, mostly due to normal field decline, dispositions and higher unplanned downtime in the United Kingdom.

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Asia Pacific and Middle East

	2013	2012	2011
Income from Continuing Operations (millions of dollars)	**$ 3,591**	3,996	3,093
Average Net Production			
Crude oil (MBD)			
Consolidated operations	**80**	68	99
Equity affiliates	**15**	15	16
Total crude oil	**95**	83	115
Natural gas liquids (MBD)			
Consolidated operations	**12**	16	12
Equity affiliates	**7**	8	7
Total natural gas liquids	**19**	24	19
Natural gas (MMCFD)			
Consolidated operations	**709**	672	695
Equity affiliates	**481**	485	492
Total natural gas	**1,190**	1,157	1,187
Total Production (MBOED)	**312**	300	332
Average Sales Prices			
Crude oil (dollars per barrel)			
Consolidated operations	**$104.78**	108.20	109.84
Equity affiliates	**105.44**	108.07	106.96
Total crude oil	**104.88**	108.18	109.46
Natural gas liquids (dollars per barrel)			
Consolidated operations	**73.82**	79.26	72.87
Equity affiliates	**73.31**	77.30	70.62
Total natural gas liquids	**73.63**	78.64	71.98
Natural gas (dollars per thousand cubic feet)			
Consolidated operations	**10.61**	10.63	9.82
Equity affiliates	**8.98**	8.54	5.93
Total natural gas	**9.95**	9.75	8.21

The Asia Pacific and Middle East segment has producing operations in China, Indonesia, Malaysia, Australia, Timor-Leste and Qatar, as well as exploration activities in Bangladesh and Brunei. During 2013, Asia Pacific and Middle East contributed 13 percent of our worldwide liquids production and 30 percent of our natural gas production.

2013 vs. 2012

Asia Pacific and Middle East earnings decreased 10 percent in 2013 compared with 2012. The decrease in earnings was largely due to:

- Lower gains from asset dispositions. Amounts realized from dispositions in 2012 included the $937 million after-tax gain on sale of our Vietnam business, in addition to the $133 million after-tax loss on further dilution of our equity interest in APLNG from 42.5 percent to 37.5 percent.
- Higher DD&A, mostly due to increased production in China.
- A $116 million after-tax charge associated with a settlement.

- Lower crude oil prices.
- Higher operating expenses and production taxes.
- The absence of a $72 million tax-related charge in 2012.

These decreases to earnings were partially offset by:

- Higher crude oil and LNG volumes.
- A $146 million after-tax insurance settlement associated with the Bohai Bay seepage incidents.
- The absence of an $89 million after-tax charge related to the Bohai Bay settlement with the China State Oceanic Administration in 2012.
- Higher equity earnings, mainly due to an $85 million tax benefit from foreign currency exchange rate movements.

Average production increased 4 percent in 2013. The improvement was largely due to:

- Increased production in Bohai Bay, China.
- New production from Panyu in the South China Sea.
- The continued ramp-up of production in Malaysia.
- Lower planned downtime, mainly from our Bayu-Undan Field and Darwin LNG facility.

These increases were partly offset by normal field decline and the Vietnam disposition.

2012 vs. 2011

Asia Pacific and Middle East earnings increased 29 percent in 2012 compared with 2011. 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 2012 consisted of the Vietnam gain and the APLNG loss on further dilution from 42.5 percent to 37.5 percent, compared with a $279 million after-tax loss on the initial dilution of our interest in APLNG from 50 percent to 42.5 percent in 2011. 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.

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Other International

	2013	2012	2011
Income (Loss) from Continuing Operations (millions of dollars)	**$ (6)**	359	(377)
Average Net Production			
Crude oil (MBD)			
Consolidated operations	**26**	40	8
Equity affiliates	**4**	13	29
Total crude oil	**30**	53	37
Natural gas (MMCFD)	**25**	18	1
Total Production (MBOED)	**34**	56	37
Average Sales Prices			
Crude oil (dollars per barrel)			
Consolidated operations	**$107.21**	110.75	98.30
Equity affiliates	**72.43**	96.50	101.62
Total crude oil	**101.91**	107.56	101.14
Natural gas (dollars per thousand cubic feet)	**5.38**	5.55	0.09

The Other International segment includes producing operations in Libya and Russia, as well as exploration activities in Angola, Senegal and Azerbaijan. During 2013, Other International contributed 4 percent of our worldwide liquids production.

2013 vs. 2012

Other International operations reported a loss of $6 million in 2013, compared with earnings of $359 million in 2012. The decrease in earnings was mainly due to the absence of the $443 million after-tax gain on disposition of our interest in NMNG in 2012. Lower volumes from Libya also contributed to the reduction. These decreases were partially offset by lower impairments. Earnings in 2012 included a $108 million after-tax impairment associated with the N Block in the Caspian Sea.

Average production decreased 39 percent in 2013, largely as a result of the shutdown of the Es Sider crude oil export terminal in Libya at the end of July 2013 and the disposition of our interest in NMNG in 2012. These decreases were partially offset by higher production from Libya during the first six months of 2013, compared with the ramp-up of production in 2012 following their period of civil unrest. Libya production remains shut-in, as the Es Sider Terminal closure has continued into the first quarter of 2014.

2012 vs. 2011

Other International earnings were $359 million in 2012, a $736 million increase compared with 2011. Earnings in 2012 primarily benefitted from the NMNG disposition, 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 the N Block impairment.

Average production increased 51 percent in 2012, mainly due to the resumption of production in Libya, partly offset by field decline in Russia and the disposition of our interest in NMNG.

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Asset Dispositions
In 2013, we sold our 8.4 percent interest in Kashagan for $5.4 billion, and we sold our Algeria business for $1.65 billion. We also have agreements to sell our Nigeria business, which includes its upstream affiliates and Brass LNG. Results of operations related to Kashagan, Algeria and Nigeria have been classified as discontinued operations in all periods presented in this Form 10-K. For additional information, see Note 3—Discontinued Operations and Note 6—Assets Held for Sale or Sold, in the Notes to Consolidated Financial Statements.

LUKOIL Investment

		Millions of Dollars		
		2013	2012	2011
Income from Continuing Operations	$	**-**	-	239

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.

Corporate and Other

		Millions of Dollars		
		2013	2012	2011
Income (Loss) from Continuing Operations				
Net interest	$	**(530)**	(648)	(710)
Corporate general and administrative expenses		**(213)**	(313)	(190)
Technology		**(6)**	(4)	15
Separation costs		**-**	(84)	(25)
Other		**(71)**	56	(50)
	$	**(820)**	(993)	(960)

2013 vs. 2012

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 18 percent in 2013, compared with 2012, primarily due to the absence of a $68 million after-tax premium on early debt retirement in 2012 and lower interest expense on lower average debt levels. These improvements were partially offset by the absence of the $33 million after-tax interest benefit from the 2012 favorable resolution of the PDVSA ICC arbitration. For additional information on the ICC arbitration, see the Results of Operations for Lower 48 and Latin America.

Corporate general and administrative expenses decreased 32 percent in 2013, mainly due to lower pension settlement expense and lower costs related to compensation and benefit plans. Pension settlement expense incurred in 2013 was $41 million after-tax, compared with $87 million after-tax in 2012.

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.

Separation costs consist of expenses related to the separation of our Downstream business into a stand-alone, publicly traded company, Phillips 66.

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. “Other” expenses increased $127 million in 2013, primarily as a result of higher tax-related adjustments, the absence of a $39 million after-tax settlement which benefitted 2012 and higher foreign currency transaction losses.

2012 vs. 2011

Net interest decreased 9 percent in 2012 compared with 2011, 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 reported a loss of $4 million in 2012, compared to earnings of $15 million in 2011, primarily as a result of lower licensing revenues.

Separation costs increased $59 million in 2012 and mainly included costs related to compensation and benefit plans.

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.

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CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars Except as Indicated		
	2013	2012	2011
Net cash provided by continuing operating activities	$ **15,801**	13,458	13,953
Net cash provided by discontinued operations	**286**	464	5,693
Cash and cash equivalents	**6,246**	3,618	5,780
Short-term debt	**589**	955	1,013
Total debt	**21,662**	21,725	22,623
Total equity	**52,492**	48,427	65,749
Percent of total debt to capital*	**29 %**	31	26
Percent of floating-rate debt to total debt**	**8 %**	9	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 2013, we received $10,220 million in proceeds from asset sales. We used the remaining $748 million of our restricted cash balance, received in connection with the separation of Phillips 66, solely to pay dividends. During 2013, the primary uses of our available cash were $15,537 million to support our ongoing capital expenditures and investments; $3,334 million to pay dividends on our common stock; $2,810 million to prepay the remaining balance of our joint venture acquisition obligation with our 50 percent owned FCCL Partnership; and $946 million to repay debt. During 2013, cash and cash equivalents increased by $2,628 million, to $6,246 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 expenditures and investments, dividend payments and required debt payments.

Significant Sources of Capital

Operating Activities
During 2013, cash provided by continuing operating activities was $15,801 million, a 17 percent increase from 2012. The increase was primarily related to lower income taxes due to a greater proportion of volumes in areas with more favorable fiscal regimes. During 2012, cash provided by continuing operations was $13,458 million, compared with $13,953 million in 2011.

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 2013 production from continuing operations averaged 1,502 MBOED. 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 2014 is expected to be 1,550 MBOED, excluding Libya.

To maintain or grow our production volumes, we must continue to add to our proved reserve base. Our total reserve replacement in 2013 was 147 percent. Excluding the impact of sales and purchases, the organic reserve replacement was 179 percent of 2013 production. Over the five-year period ended December 31, 2013, our reserve replacement was 69 percent (including 95 percent from consolidated operations) reflecting the disposition of our interest in LUKOIL and the impact of asset dispositions. Excluding these items and purchases, our five-year organic reserve replacement was 145 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.

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 2013, 2012 and 2011, 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 2013 were $10,220 million, primarily from the sale of our 8.4 percent equity interest in Kashagan, the sale of our Algeria business, the sale of the majority of our producing zones in the Cedar Creek Anticline, the sale of our interest in the Clyden undeveloped oil sands leasehold, the sale of our 39 percent equity interest in Phoenix Park and the sale of a portion of our working interests in Browse and Canning basins. This compares with proceeds of $2,132 million in 2012, 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.

As previously announced, we entered into agreements to sell our Nigeria business, which includes its upstream affiliates and Brass LNG. The upstream sale is anticipated to close in the first quarter of 2014 and generate proceeds of approximately $1.5 billion, after customary adjustments. We have received deposits to date of $500 million, with the remainder of approximately $1.0 billion due at closing. The buyer has until March 31, 2014, to close on Brass LNG. The sale of Brass LNG would generate proceeds of approximately $0.16 billion, after customary adjustments.

We continue to evaluate opportunities to further optimize the portfolio.

Commercial Paper and Credit Facilities

At December 31, 2013, 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 agreements call for commitment fees on available, but unused, amounts. The agreements also contain early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

Our primary funding source for short-term working capital needs is the ConocoPhillips $6.35 billion commercial paper program. Commercial paper maturities are generally limited to 90 days. We also have the ConocoPhillips Qatar Funding Ltd. $1.15 billion commercial paper program, which is used to fund commitments relating to QG3. At both December 31, 2013 and 2012, we had no direct outstanding borrowings or letters of credit issued under the revolving credit facility. In addition, under the ConocoPhillips Qatar Funding Ltd. commercial paper program, there was $961 million of commercial paper outstanding at December 31, 2013, compared with $1,055 million at December 31, 2012. Since we had $961 million of commercial paper outstanding and had issued no letters of credit, we had access to $6.5 billion in borrowing capacity under our revolving credit facility at December 31, 2013.

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 requiring us to post collateral. Many of these contracts and instruments permit us to post either cash or letters of credit as collateral. At December 31, 2013 and December 31, 2012, we had direct bank letters of credit of $827 million and $852 million, respectively, which secured performance obligations related to various purchase commitments 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.

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 both December 31, 2013 and December 31, 2012, was $21.7 billion. During 2013, we repaid bonds at maturity totaling $850 million. In June 2013, we incurred a capital lease obligation of $906 million. For more information, see Note 11—Debt, in the Notes to Consolidated Financial Statements.

We were obligated to contribute $7.5 billion, plus interest, over a 10-year period that began in 2007, to our 50 percent owned FCCL Partnership. Quarterly principal and interest payments of $237 million began in the second quarter of 2007. The principal portion of these payments totaled $772 million in 2013. In December 2013, we paid the remaining balance of the obligation, which totaled $2,810 million and is included in the "Other" line in the financing activities section of our consolidated statement of cash flows.

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This $2,810 million prepayment substantially increases the FCCL Partnership's ability to make distributions to its partners or fund future capital requirements without contributions from the partners. Interest accrued 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 July 2013, we announced a 4.5 percent increase in the quarterly dividend rate to 69 cents per share. Additionally, on February 5, 2014, we announced a dividend of 69 cents per share. The dividend will be paid March 3, 2014, to stockholders of record at the close of business on February 18, 2014.

In February 2014, the $400 million 4.75% Notes due 2014 were repaid at maturity.

Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations of our continuing operations as of December 31, 2013:

	Millions of Dollars				
	Payments Due by Period				
	Total	Up to 1 Year	Years 2-3	Years 4-5	After 5 Years
Debt obligations (a)	$ 20,740	514	3,678	1,838	14,710
Capital lease obligations (b)	922	75	100	108	639
Total debt	21,662	589	3,778	1,946	15,349
Interest on debt and other obligations	15,259	1,137	2,076	1,900	10,146
Operating lease obligations (c)	2,749	602	1,002	500	645
Purchase obligations (d)	23,338	10,008	3,548	2,368	7,414
Other long-term liabilities					
Pension and postretirement benefit contributions (e)	2,117	560	737	820	-
Asset retirement obligations (f)	10,076	489	1,333	805	7,449
Accrued environmental costs (g)	348	50	61	40	197
Unrecognized tax benefits (h)	144	144	(h)	(h)	(h)
Total	$ 75,693	13,579	12,535	8,379	41,200

(a) Includes $404 million of net unamortized premiums and discounts. See Note 11—Debt, in the Notes to Consolidated Financial Statements, for additional information.

(b) Capital lease obligations are presented on a discounted basis.

(c) Operating lease obligations are presented on an undiscounted basis.

(d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms, presented on an undiscounted basis. 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 $9,610 million.

Purchase obligations of $10,538 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.

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(e) Represents contributions to qualified and nonqualified pension and postretirement benefit plans for the years 2014 through 2018. For additional information related to expected benefit payments subsequent to 2018, see Note 19—Employee Benefit Plans, in the Notes to Consolidated Financial Statements.

(f) Represents estimated discounted costs to retire and remove long-lived assets at the end of their operations.

(g) Represents estimated costs for accrued environmental expenditures presented on a discounted basis for costs acquired in various business combinations and an undiscounted basis for all other accrued environmental costs.

(h) Excludes unrecognized tax benefits of $511 million because the ultimate disposition and timing of any payments to be made with regard to such amounts are not reasonably estimable. Although unrecognized tax benefits are not a contractual obligation, they are presented in this table because they represent potential demands on our liquidity.

Capital Spending

	Millions of Dollars		
	2013	2012	2011
Alaska	$ **1,140**	828	774
Lower 48 and Latin America	**5,234**	5,251	3,882
Canada	**2,232**	2,184	1,761
Europe	**3,115**	2,860	2,222
Asia Pacific and Middle East	**3,382**	2,430	2,325
Other International	**252**	415	8
Corporate and Other	**182**	204	242
Capital expenditures and investments from continuing operations	**15,537**	14,172	11,214
Discontinued operations in Kashagan, Nigeria and Algeria	**609**	817	1,038
Joint venture acquisition obligation (principal)—Canada*	**772**	733	695
Capital Program	$ **16,918**	15,722	12,947

**Excludes $2,810 million prepayment in the fourth quarter of 2013.*

Our capital expenditures and investments from continuing operations for the three-year period ended December 31, 2013, totaled $40.9 billion. The expenditures over this period supported key exploration and developments, primarily:

- Oil and natural gas exploration and development activities in the Lower 48, including the Eagle Ford and Bakken shale plays, and the Permian Basin.
- Development of coalbed methane projects associated with the APLNG joint venture in Australia.
- In Europe, development activities in the Greater Ekofisk, Jasmine and Clair Ridge areas, and appraisal activities in the Greater Clair Area.
- Oil sands development and ongoing liquids-focused plays in Canada.
- Alaska activities related to development in the Greater Kuparuk Area, the Greater Prudhoe Area, and the Western North Slope.
- Exploration leases and wells in deepwater Gulf of Mexico.
- Continued development of offshore fields in Malaysia and ongoing exploration and development activity onshore and offshore Indonesia and Australia.

2014 CAPITAL BUDGET

Our 2014 capital budget is $16.7 billion, essentially flat compared with our 2013 capital program.

We are directing approximately 55 percent of our 2014 capital expenditures budget for continuing operations to North America. These funds are expected to be directed toward:

- Increased investment in the Company's successful development drilling programs in the Eagle Ford, Bakken and Permian.
- Higher allocation of capital to Alaska compared to 2013, reflecting increased spending on the CD5 development and higher activity resulting from improved fiscal terms from the passage of the More Alaska Production Act.
- Increased exploration and appraisal activity in several North American unconventional plays, including the Permian, Niobrara, Canol and Duvernay.
- Higher levels of spending at Surmont Phase 2, in anticipation of first production in 2015.
- Increased conventional exploration drilling in the deepwater Gulf of Mexico.

We are directing approximately 45 percent of our 2014 capital expenditures budget for continuing operations to Europe, Asia Pacific and other international businesses. These funds are expected to be directed toward:

- Peak spending at the APLNG Project, in anticipation of first LNG sales.
- Conventional exploration drilling offshore Angola, Senegal and the Browse Basin.
- Investments in Eldfisk II, Britannia Long-term Compression and Clair Ridge.

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 arising in the ordinary course of business have been made against ConocoPhillips. 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. With respect to income-tax-related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. As we learn new facts concerning contingencies, we reassess our position 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.

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 and Canada.

An example is the use of hydraulic fracturing, an essential completion technique that facilitates production of oil and natural gas otherwise trapped in lower permeability rock formations. A range of local, state, federal or national laws and regulations currently govern hydraulic fracturing operations, with hydraulic fracturing currently prohibited in some jurisdictions. 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, 2012, we reported we had been notified of potential liability under CERCLA and comparable state laws at 11 sites around the United States. At December 31, 2013, we had been notified of 4 new sites, bringing the number of unresolved sites with potential liability to 15 sites.

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 $546 million in 2013 and are expected to be about $580 million per year in 2014 and 2015. Capitalized environmental costs were $357 million in 2013 and are expected to be about $480 million per year in 2014 and 2015.

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 or international 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 other agency 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, 2013, our balance sheet included total accrued environmental costs of $348 million, compared with $364 million at December 31, 2012, for remediation activities in the U.S. and Canada. We expect to incur a substantial amount of these expenditures within the next 30 years.

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

Climate Change

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

- European Emissions Trading Scheme (ETS), the program through which many of the European Union (EU) member states are implementing the Kyoto Protocol. Our cost of compliance with the EU ETS in 2013 was approximately $2 million (net share pre-tax).
- 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 tonnes 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 2013 was approximately $6 million.
- 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 2013 was approximately $44 million (net share pre-tax).
- Cap and trade programs in certain jurisdictions, including the Australian Clean Energy Legislation, which took effect in July 2012. Our cost of compliance with the Australian Clean Energy Legislation in 2013 was approximately $10 million (net share pre-tax).

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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 2012 the Company reduced GHG emissions by approximately 1,000,000 metric 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 $6 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.

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 2013, 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 $1,830 million and the accumulated impairment reserve was $558 million. The weighted-average judgmental percentage probability of ultimate failure was approximately 56 percent, and the weighted-average amortization period was approximately three years. If that judgmental percentage were to be raised by 5 percent across all calculations, pretax leasehold impairment expense in 2014 would increase by approximately $39 million. At year-end 2013, the remaining $6,708 million of gross capitalized unproved property costs consisted primarily 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, the majority of which are not expected to move to proved properties in 2014.

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

If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. The accounting notion of “sufficient progress” is a judgmental area, but the accounting rules do prohibit continued capitalization of suspended well costs on the expectation 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 2013, total suspended well costs were $994 million, compared with $1,038 million at year-end 2012. For additional information on suspended wells, including an aging analysis, see Note 8—Suspended Wells, in the Notes to Consolidated Financial Statements.

Proved Reserves

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

Despite the inherent imprecision in these engineering estimates, accounting rules require disclosure of “proved” reserve estimates due to the importance of these estimates to better understand the perceived value and future cash flows of a company’s 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 current 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 2013, the net book value of productive properties, plants and equipment (PP&E) subject to a unit-of-production calculation was approximately $59 billion and the DD&A recorded on these assets in 2013 was approximately $7.0 billion. The estimated proved developed reserves for our consolidated operations were 4.9 billion BOE at the end of 2012 and 4.9 billion BOE at the end of 2013. 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 2013 would have increased by an estimated $370 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 recorded as a liability and an increase to PP&E at the time of installation of the asset based on estimated discounted costs. Estimating future asset removal costs is difficult. Most of these removal obligations are many years, or decades, in the future and the contracts and regulations often have vague descriptions of what removal practices and criteria must be met when the removal event actually occurs. Asset removal technologies and costs, regulatory and other compliance considerations, expenditure timing, and other inputs into valuation of the obligation, including discount and inflation rates, are also subject to change.

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 $120 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $60 million. In determining the discount rate, we use yields on high-quality fixed income investments matched to the estimated benefit cash flows of our plans. 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. See Note 19—Employee Benefit Plans, in the Notes to Consolidated Financial Statements, for additional information.

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

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

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

- Fluctuations in crude oil, bitumen, natural gas, LNG and natural gas liquids prices.
- 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, bitumen, natural gas, LNG and natural gas liquids.
- 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, cyber attacks or infrastructure constraints or disruptions.
- 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 and 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, execute asset dispositions.
- 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.

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. 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 market knowledge to capture 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, 2013, 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, 2013 and 2012, 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, 2013 and 2012, 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 at year-end 2012 was estimated based on the net present value of the future cash flows, discounted at an effective yield rate of 0.7 percent. The discount rate was 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. In December 2013, we paid the remaining balance of the obligation, which totaled $2,810 million.

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Expected Maturity Date	Debt: Fixed Rate Maturity	Debt: Average Interest Rate	Debt: Floating Rate Maturity	Debt: Average Interest Rate	Joint Venture Acquisition Obligation: Fixed Rate Maturity	Joint Venture Acquisition Obligation: Average Interest Rate
	Millions of Dollars Except as Indicated					
Year-End 2013						
2014	**$ 400**	**4.75 %**	**$ 100**	**0.21 %**	**$ -**	**-%**
2015	**1,500**	**4.60**	**-**	**-**	**-**	**-**
2016	**1,273**	**5.52**	**861**	**0.02**	**-**	**-**
2017	**1,001**	**1.06**	**-**	**-**	**-**	**-**
2018	**797**	**5.74**	**-**	**-**	**-**	**-**
Remaining years	**14,121**	**6.27**	**283**	**0.05**	**-**	**-**
Total	**$ 19,092**		**$ 1,244**		**$ -**	
Fair value	**$ 22,309**		**$ 1,244**		**$ -**	
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	

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.

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At December 31, 2013 and 2012, 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, 2013, or 2012, exchange rates. The notional and fair market values of these positions at December 31, 2013 and 2012, were as follows:

Foreign Currency Exchange Derivatives	In Millions				
		Notional*		Fair Market Value**	
		2013	2012	**2013**	2012
Sell U.S. dollar, buy British pound	USD	**-**	2,573	**-**	31
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	**6**	43	**-**	(2)
Buy euro, sell British pound	EUR	**-**	96	**-**	-
Buy British pound, sell euro	GBP	**17**	-	**-**	-

** Denominated in U.S. dollars (USD), euro (EUR), and British pound (GBP).*
*** Denominated in U.S. dollars.*

For additional information about our use of derivative instruments, see Note 15—Derivative and Financial Instruments, in the Notes to Consolidated Financial Statements.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONOCOPHILLIPS

INDEX TO FINANCIAL STATEMENTS

Report of Management

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

Assessment of Internal Control Over Financial Reporting

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

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

Management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2013. 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 (1992)*. Based on our assessment, we believe the company's internal control over financial reporting was effective as of December 31, 2013.

Ernst & Young LLP has issued an audit report on the company's internal control over financial reporting as of December 31, 2013, and their report is included herein.

/s/ Ryan M. Lance

Ryan M. Lance
Chairman and
Chief Executive Officer

/s/ Jeff W. Sheets

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

February 25, 2014

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
ConocoPhillips

We have audited the accompanying consolidated balance sheets of ConocoPhillips as of December 31, 2013 and 2012, 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, 2013. 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, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, 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, 2013, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 25, 2014, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 25, 2014

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
ConocoPhillips

We have audited ConocoPhillips' internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (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, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2013 consolidated financial statements of ConocoPhillips and our report dated February 25, 2014, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 25, 2014

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Consolidated Income Statement **ConocoPhillips**

Years Ended December 31	Millions of Dollars			
		2013	2012	2011
Revenues and Other Income				
Sales and other operating revenues	$	**54,413**	57,967	64,196
Equity in earnings of affiliates		**2,219**	1,911	1,239
Gain on dispositions		**1,242**	1,657	370
Other income		**374**	469	264
Total Revenues and Other Income		**58,248**	62,004	66,069
Costs and Expenses				
Purchased commodities		**22,643**	25,232	29,797
Production and operating expenses		**7,238**	6,793	6,426
Selling, general and administrative expenses		**854**	1,106	865
Exploration expenses		**1,232**	1,500	1,038
Depreciation, depletion and amortization		**7,434**	6,580	6,827
Impairments		**529**	680	321
Taxes other than income taxes		**2,884**	3,546	3,999
Accretion on discounted liabilities		**434**	394	422
Interest and debt expense		**612**	709	954
Foreign currency transaction (gains) losses		**(58)**	41	24
Total Costs and Expenses		**43,802**	46,581	50,673
Income from continuing operations before income taxes		**14,446**	15,423	15,396
Provision for income taxes		**6,409**	7,942	8,208
Income From Continuing Operations		**8,037**	7,481	7,188
Income from discontinued operations*		**1,178**	1,017	5,314
Net income		**9,215**	8,498	12,502
Less: net income attributable to noncontrolling interests		**(59)**	(70)	(66)
Net Income Attributable to ConocoPhillips	$	**9,156**	8,428	12,436
Amounts Attributable to ConocoPhillips Common Shareholders:				
Income from continuing operations	$	**7,978**	7,413	7,127
Income from discontinued operations		**1,178**	1,015	5,309
Net Income	$	**9,156**	8,428	12,436
Net Income Attributable to ConocoPhillips Per Share of Common Stock *(dollars)*				
Basic				
Continuing operations	$	**6.47**	5.95	5.18
Discontinued operations		**0.96**	0.82	3.86
Net Income Attributable to ConocoPhillips Per Share of Common Stock	$	**7.43**	6.77	9.04
Diluted				
Continuing operations	$	**6.43**	5.91	5.14
Discontinued operations		**0.95**	0.81	3.83
Net Income Attributable to ConocoPhillips Per Share of Common Stock	$	**7.38**	6.72	8.97
Dividends Paid Per Share of Common Stock *(dollars)*	$	**2.70**	2.64	2.64
Average Common Shares Outstanding *(in thousands)*				
Basic		**1,230,963**	1,243,799	1,375,035
Diluted		**1,239,803**	1,253,093	1,387,100
**Net of provision for income taxes on discontinued operations of:*	*$*	***283***	*745*	*2,291*

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Comprehensive Income **ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2013	2012	2011
Net Income	$ **9,215**	8,498	12,502
Other comprehensive income (loss)			
Defined benefit plans			
Prior service credit arising during the period	**1**	2	19
Reclassification adjustment for amortization of prior service cost (credit) included in net income	**(5)**	(5)	2
Net change	**(4)**	(3)	21
Net actuarial gain (loss) arising during the period	**688**	(704)	(1,185)
Reclassification adjustment for amortization of net actuarial losses included in net income	**294**	430	226
Net change	**982**	(274)	(959)
Nonsponsored plans*	**10**	8	(50)
Income taxes on defined benefit plans	**(387)**	132	375
Defined benefit plans, net of tax	**601**	(137)	(613)
Unrealized holding gain on securities	**-**	-	8
Reclassification adjustment for gain included in net income	**-**	-	(255)
Income taxes on unrealized holding gain on securities	**-**	-	89
Unrealized loss on securities, net of tax	**-**	-	(158)
Foreign currency translation adjustments	**(2,705)**	929	(387)
Reclassification adjustment for gain included in net income	**(4)**	(155)	(516)
Income taxes on foreign currency translation adjustments	**23**	(16)	(14)
Foreign currency translation adjustments, net of tax	**(2,686)**	758	(917)
Hedging activities	**-**	6	1
Income taxes on hedging activities	**-**	-	-
Hedging activities, net of tax	**-**	6	1
Other Comprehensive Income (Loss), Net of Tax	**(2,085)**	627	(1,687)
Comprehensive Income	**7,130**	9,125	10,815
Less: comprehensive income attributable to noncontrolling interests	**(59)**	(70)	(66)
Comprehensive Income Attributable to ConocoPhillips	$ **7,071**	9,055	10,749

**Plans for which ConocoPhillips is not the primary obligor—primarily those administered by equity affiliates.*
See Notes to Consolidated Financial Statements.

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Consolidated Balance Sheet		ConocoPhillips
At December 31	Millions of Dollars	
	2013	2012
Assets		
Cash and cash equivalents	$ **6,246**	3,618
Short-term investments*	**272**	-
Restricted cash	**-**	748
Accounts and notes receivable (net of allowance of $8 million in 2013 and $10 million in 2012)	**8,273**	8,929
Accounts and notes receivable—related parties	**214**	253
Inventories	**1,194**	965
Prepaid expenses and other current assets	**2,824**	9,476
Total Current Assets	**19,023**	23,989
Investments and long-term receivables	**23,907**	23,489
Loans and advances—related parties	**1,357**	1,517
Net properties, plants and equipment (net of accumulated depreciation, depletion and amortization of $65,321 million in 2013 and $58,916 million in 2012)	**72,827**	67,263
Other assets	**943**	886
Total Assets	$ **118,057**	117,144
Liabilities		
Accounts payable	$ **9,250**	9,154
Accounts payable—related parties	**64**	859
Short-term debt	**589**	955
Accrued income and other taxes	**2,713**	3,366
Employee benefit obligations	**842**	742
Other accruals	**1,671**	2,367
Total Current Liabilities	**15,129**	17,443
Long-term debt	**21,073**	20,770
Asset retirement obligations and accrued environmental costs	**9,883**	8,947
Joint venture acquisition obligation—related party	**-**	2,810
Deferred income taxes	**15,220**	13,185
Employee benefit obligations	**2,459**	3,346
Other liabilities and deferred credits	**1,801**	2,216
Total Liabilities	**65,565**	68,717
Equity		
Common stock (2,500,000,000 shares authorized at $.01 par value)		
Issued (2013—1,768,169,906 shares; 2012—1,762,247,949)		
Par value	**18**	18
Capital in excess of par	**45,690**	45,324
Treasury stock (at cost: 2013—542,230,673; 2012—542,230,673)	**(36,780)**	(36,780)
Accumulated other comprehensive income	**2,002**	4,087
Retained earnings	**41,160**	35,338
Total Common Stockholders' Equity	**52,090**	47,987
Noncontrolling interests	**402**	440
Total Equity	**52,492**	48,427
Total Liabilities and Equity	$ **118,057**	117,144
**Includes marketable securities of:*	*$ **135***	*-*

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Cash Flows **ConocoPhillips**

Years Ended December 31		Millions of Dollars	
	2013	2012	2011
Cash Flows From Operating Activities			
Net income	$ **9,215**	8,498	12,502
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	**7,434**	6,580	6,827
Impairments	**529**	680	321
Dry hole costs and leasehold impairments	**443**	874	469
Accretion on discounted liabilities	**434**	394	422
Deferred taxes	**1,311**	1,397	340
Undistributed equity earnings	**(822)**	(596)	(131)
Gain on dispositions	**(1,242)**	(1,657)	(370)
Income from discontinued operations	**(1,178)**	(1,017)	(5,314)
Other	**(371)**	(456)	(403)
Working capital adjustments			
Decrease (increase) in accounts and notes receivable	**744**	(1,866)	(938)
Decrease (increase) in inventories	**(278)**	210	(81)
Decrease (increase) in prepaid expenses and other current assets	**(83)**	513	(300)
Increase in accounts payable	**183**	1,103	1,297
Decrease in taxes and other accruals	**(518)**	(1,199)	(688)
Net cash provided by continuing operating activities	**15,801**	13,458	13,953
Net cash provided by discontinued operations	**286**	464	5,693
Net Cash Provided by Operating Activities	**16,087**	13,922	19,646
Cash Flows From Investing Activities			
Capital expenditures and investments	**(15,537)**	(14,172)	(11,214)
Proceeds from asset dispositions	**10,220**	2,132	2,192
Net sales (purchases) of short-term investments	**(263)**	597	400
Collection of advances/loans—related parties	**145**	114	98
Other	**(212)**	821	50
Net cash used in continuing investing activities	**(5,647)**	(10,508)	(8,474)
Net cash provided by (used in) discontinued operations	**(604)**	(1,119)	1,459
Net Cash Used in Investing Activities	**(6,251)**	(11,627)	(7,015)
Cash Flows From Financing Activities			
Issuance of debt	**-**	1,996	-
Repayment of debt	**(946)**	(2,565)	(934)
Special cash distribution from Phillips 66	**-**	7,818	-
Change in restricted cash	**748**	(748)	-
Issuance of company common stock	**20**	138	96
Repurchase of company common stock	**-**	(5,098)	(11,123)
Dividends paid	**(3,334)**	(3,278)	(3,632)
Other	**(3,621)**	(725)	(684)
Net cash used in continuing financing activities	**(7,133)**	(2,462)	(16,277)
Net cash used in discontinued operations	**-**	(2,019)	(28)
Net Cash Used in Financing Activities	**(7,133)**	(4,481)	(16,305)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(75)**	24	-
Net Change in Cash and Cash Equivalents	**2,628**	(2,162)	(3,674)
Cash and cash equivalents at beginning of period	**3,618**	5,780	9,454
Cash and Cash Equivalents at End of Period	$ **6,246**	3,618	5,780

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, 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
Net income							**9,156**	**59**	**9,215**
Other comprehensive loss					**(2,085)**				**(2,085)**
Dividends paid							**(3,334)**		**(3,334)**
Distributions to noncontrolling interests and other								**(97)**	**(97)**
Distributed under benefit plans		**366**							**366**
December 31, 2013	**$ 18**	**45,690**	**(36,780)**	**-**	**2,002**	**-**	**41,160**	**402**	**52,492**

See Notes to Consolidated Financial Statements.

Note 1—Accounting Policies

- **Consolidation Principles and Investments—**Our consolidated financial statements include the accounts of majority-owned, controlled subsidiaries and variable interest entities where we are the primary beneficiary. The equity method is used to account for investments in affiliates in which we have the ability to exert significant influence over the affiliates' operating and financial policies. 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 the 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 Algeria and Nigeria businesses have been classified as discontinued operations for all periods presented. See Note 3—Discontinued Operations, for additional information.

  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).

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- **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 are recorded as a component of revenue.

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

- **Short-Term Investments—**Investments in bank time deposits and marketable securities (commercial paper and government obligations) with original maturities of greater than 90 days but less than one year are classified as short-term investments. See Note 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. 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 8—Suspended Wells, for additional information on suspended wells.

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

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

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

- **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.

  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.

- **Share-Based Compensation—**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. 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 and temporary differences related to cumulative translation adjustment (CTA) 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.

- **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, 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—Change in Accounting Principles

Effective January 1, 2013, we early adopted, on a prospective basis, Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) No. 2013-05, “Parent’s Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity.” This ASU clarifies that the CTA should not be released into net income unless a parent sells a part of its investment within a foreign entity which represents the complete or substantially complete liquidation of the reporting parent’s investment in the broader foreign entity. The ASU also requires the release of all the related CTA into net income upon gaining control in a step acquisition of an equity method investment that is considered to be a stand-alone foreign entity, and a pro rata release of the related CTA into net income upon a partial sale of an interest in an equity method investment that is considered to be a stand-alone foreign entity. There was no impact to our consolidated financial statements from the early adoption of this standard.

Note 3—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. In connection with the separation, Phillips 66 distributed approximately $7.8 billion to us in a special cash distribution. The principal funds from the special cash distribution were designated 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. No balance remained from the cash distribution as of December 31, 2013. We also entered into several agreements with Phillips 66 in order to effect the separation and govern our relationship with Phillips 66.

Sales and other operating revenues and income from discontinued operations related to Phillips 66 during 2012 and 2011 were as follows:

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

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, respectively. No separation costs were incurred in 2013.

Prior to the separation, commodity sales to Phillips 66 were $4,973 million and $15,822 million for the years ended December 31, 2012 and 2011, respectively. Commodity purchases from Phillips 66 prior to the separation were $166 million and $516 million for the years ended December 31, 2012 and 2011, respectively. 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.

Other Discontinued Operations
As part of our ongoing strategic asset disposition program, we agreed to sell our interest in Kashagan and our Algeria and Nigeria businesses (collectively, the “Disposition Group”). The Disposition Group was previously part of the Other International operating segment.

On November 26, 2012, we notified government authorities in Kazakhstan and co-venturers of our intent to sell the Company’s 8.4 percent interest in Kashagan to ONGC Videsh Limited (OVL). On July 2, 2013, we received notification from the government of Kazakhstan indicating it was exercising its right to pre-empt the proposed sale to OVL and designating KazMunayGas (KMG) as the entity to acquire the interest. On October 31, 2013, we completed the transaction with KMG for total proceeds of $5,392 million and recognized a pre-tax gain of $22 million, which is included in the “Income from discontinued operations” line on the consolidated income statement. We recorded pre-tax impairments of $43 million and $606 million in the first quarter of 2013 and the fourth quarter of 2012, respectively. At the time of disposition, the carrying value of the net assets related to our interest in Kashagan was $5,370 million, which included $212 million of other current assets, $239 million of long-term receivables, $5,149 million of PP&E, $144 million of other current liabilities, and $86 million of asset retirement obligations (ARO).

On December 18, 2012, we entered into an agreement with Pertamina to sell our wholly owned subsidiary, ConocoPhillips Algeria Ltd. On November 27, 2013, we completed the transaction with Pertamina, resulting in proceeds of $1,652 million, which included a $175 million deposit received in December 2012. We recognized a pre-tax gain of $938 million, which is included in the “Income from discontinued operations” line on the consolidated income statement. At the time of disposition, the net carrying value of our Algerian assets was $714 million, which included $48 million of other current assets, $883 million of PP&E, $41 million of other current liabilities, $37 million of ARO, and $139 million of deferred taxes.

On December 20, 2012, we entered into agreements with affiliates of Oando PLC to sell our Nigeria business. This includes its upstream affiliates and Phillips (Brass) Limited, which owns a 17 percent interest in the Brass LNG Project. Brass LNG plans to construct an LNG facility in the Niger Delta. In order to provide additional time for Oando to obtain financing and government consents, we agreed to further extend the outside date, or the date the sales agreements may terminate if closing has not occurred, for our Nigerian upstream affiliates to February 28, 2014. We anticipate extending the outside date to enable a March 2014 closing. The upstream sale is expected to generate proceeds of approximately $1.5 billion, after customary adjustments, inclusive of deposits received. We received deposits of $15 million and $435 million in December 2013 and 2012, respectively. In February 2014, we received an additional $50 million deposit, bringing our total deposits received to $500 million. We may retain the deposits if closing does not occur due to default by the buyer or failure to obtain all consents required under Nigerian petroleum laws. The buyer has until March 31, 2014, to close on Brass LNG. The sale of our Brass LNG interest would generate proceeds of approximately $0.16 billion, after customary adjustments. As of December 31, 2013, the net carrying value of our Nigerian assets was $409 million.

At December 31, 2013, we classified $7 million of loans and advances to related parties in the “Accounts and notes receivable—related parties” line and $1,215 million of noncurrent assets in the “Prepaid expenses and other current assets” line of our consolidated balance sheet. In addition, we classified $765 million of noncurrent deferred income taxes in the “Accrued income and other taxes” line and $14 million of ARO 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	
	2013	2012
Assets		
Accounts and notes receivable	$ **376**	268
Accounts and notes receivable—related parties	**-**	1
Inventories	**9**	44
Prepaid expenses and other current assets	**72**	220
Total current assets of discontinued operations	**457**	533
Investments and long-term receivables	**60**	272
Loans and advances—related parties	**7**	29
Net properties, plants and equipment	**1,154**	6,629
Other assets	**1**	4
Total assets of discontinued operations	$ **1,679**	7,467
Liabilities		
Accounts payable	$ **419**	471
Accrued income and other taxes	**72**	125
Total current liabilities of discontinued operations	**491**	596
Asset retirement obligations and accrued environmental costs	**14**	131
Deferred income taxes	**765**	759
Total liabilities of discontinued operations	$ **1,270**	1,486

Sales and other operating revenues and income (loss) from discontinued operations related to the Disposition Group during 2013, 2012 and 2011 were as follows:

		Millions of Dollars	
	2013	2012	2011
Sales and other operating revenues from discontinued operations	$ **1,185**	1,369	1,560
Income (loss) from discontinued operations before-tax	$ **1,461**	(6)	829
Income tax expense	**283**	211	562
Income (loss) from discontinued operations	$ **1,178**	(217)	267

Note 4—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 an 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, which expires in 2033. The terminal became operational in June 2008, and we began making payments under the terminal use agreement. At December 31, 2013, the prepaid balance of the terminal use agreement was $282 million, which is primarily reflected in the “Other assets” line on our consolidated balance sheet. Freeport LNG began making loan repayments in September 2008, and the loan balance outstanding was $506 million at December 31, 2013, and $565 million at December 31, 2012.

In July 2013, we reached an agreement with Freeport LNG to terminate our long-term agreement at the Freeport LNG Terminal, subject to Freeport LNG obtaining regulatory approval and project financing for an LNG liquefaction and export facility in Texas, in which we are not a participant. Upon satisfaction of these conditions, currently expected to occur during the second half of 2014, we will pay Freeport LNG a termination fee of approximately $600 million. Freeport LNG will repay the outstanding ConocoPhillips loan used by Freeport LNG to partially fund the original construction of the terminal. When the agreement becomes effective, we expect to recognize an after-tax charge to earnings of approximately $540 million. At that time, our terminal regasification capacity will be reduced from 0.9 billion cubic feet per day to 0.4 billion cubic feet per day, until July 1, 2016, at which time it will be reduced to zero.

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 Pty Ltd (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, 2013, we have not provided any financial support to APLNG other than amounts previously contractually required. Unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of APLNG. See Note 7—Investments, Loans and Long-Term Receivables, and Note 13—Guarantees, for additional information.

Note 5—Inventories

Inventories at December 31 were:

	Millions of Dollars	
	2013	2012
Crude oil and natural gas	**$ 452**	244
Materials, supplies and other	**742**	721
	$ 1,194	965

Inventories valued on the LIFO basis totaled $343 million and $147 million at December 31, 2013 and 2012, respectively. The estimated excess of current replacement cost over LIFO cost of inventories was approximately $160 million at December 31, 2013, and $200 million at December 31, 2012. In 2013, there were no liquidations of LIFO inventory values impacting net income from continuing operations.

Note 6—Assets Held for Sale or Sold

Assets Held for Sale
Our interest in the Nigeria business was considered held for sale as of December 31, 2013. See Note 3—Discontinued Operations, for additional information.

Assets Sold
All gains or losses are reported before-tax and are included net in the "Gain on dispositions" line on the consolidated income statement.

2013
In March 2013, we sold the majority of our producing zones in the Cedar Creek Anticline for $994 million and recognized a loss on disposition of $43 million. At the time of the disposition, the carrying value of our interest, which was included in the Lower 48 and Latin America segment, was $1,037 million, which included primarily $1,066 million of PP&E and $28 million of ARO.

In June 2013, we sold a portion of our working interests in the Browse and Canning basins for $402 million. Because we retain a working interest in the unproved properties, proceeds were treated as a reduction of the carrying value of PP&E with no gain or loss on disposition recognized. Prior to the partial disposition, the carrying value of the PP&E associated with our interests, included in our Asia Pacific and Middle East segment, was $486 million.

In August 2013, we sold our interest in the Clyden undeveloped oil sands leasehold for $724 million and recognized a gain on disposition of $614 million. At the time of the disposition, the carrying value of our interest in Clyden, which was included in the Canada segment, was $110 million and was primarily classified as PP&E.

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In August 2013, we also sold our 39 percent interest in Phoenix Park Gas Processors Limited for $593 million and recognized a gain on disposition of $417 million. At the time of the disposition, the carrying value of our equity investment in Phoenix Park, which was included in our Lower 48 and Latin America segment, was $176 million.

For information on the Kashagan and Algeria sales, which are included in the "Income from discontinued operations" line on the consolidated income statement, see Note 3—Discontinued Operations.

2012
In March 2012, we sold our Vietnam business for $1,095 million and recognized a gain on disposition 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. The cost basis for the shares, which were classified as available-for-sale, was average cost.

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Note 7—Investments, Loans and Long-Term Receivables

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

	Millions of Dollars	
	2013	2012
Equity investments	$ **22,980**	22,431
Loans and advances—related parties	**1,357**	1,517
Long-term receivables	**470**	609
Other investments	**457**	449
	$ **25,264**	25,006

Equity Investments

Affiliated companies in which we had a significant equity investment at December 31, 2013, included:

- APLNG—37.5 percent owned joint venture with Origin Energy (37.5 percent) and 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, as well as exports LNG.

Summarized 100 percent earnings 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		
	2013	2012	2011
Revenues	$ **18,035**	17,903	77,263
Income before income taxes	**6,384**	5,986	11,958
Net income	**6,125**	5,767	11,089

Summarized 100 percent balance sheet information for equity method investments in affiliated companies, combined, was as follows:

	Millions of Dollars	
	2013	2012
Current assets	$ **9,073**	11,510
Noncurrent assets	**51,674**	46,743
Current liabilities	**3,416**	3,721
Noncurrent liabilities	**13,850**	9,698

Our share of income taxes incurred directly by an equity company 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, 2013, retained earnings included $1,358 million related to the undistributed earnings of affiliated companies. Dividends received from affiliates were $1,425 million, $1,351 million and $3,670 million in 2013, 2012 and 2011, 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 metric 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 metric 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 metric tonnes of LNG per year through 2035, finalized the marketing of the second train.

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. At December 31, 2013, $7.3 billion had been drawn from the facility. 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 4—Variable Interest Entities (VIEs) for additional information.

At December 31, 2013, the book value of our equity method investment in APLNG was $10,766 million, which includes $1,159 million of cumulative translation effects due to a strengthening Australian dollar relative to the U.S. dollar over time. 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 $5,160 million, resulting in a basis difference of $5,606 million on our books. The amortizable portion of the basis difference, $4,022 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 produces 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 2013, 2012 and 2011 was after-tax expense of $16 million, $19 million and $17 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, 2013, the book value of our investment in FCCL was $10,273 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 were obligated to contribute $7.5 billion, plus accrued interest, to FCCL over a 10-year period that began in 2007. In December 2013, we repaid the remaining balance of the obligation. See Note 12—Joint Venture Acquisition Obligation, for additional information on this 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 $1,005 million as described below under "Loans and Long-Term Receivables." At December 31, 2013, the book value of our equity method investment in QG3, excluding the project financing, was $1,041 million. We have terminal and pipeline use agreements with Golden Pass LNG 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.

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At December 31, 2013, significant loans to affiliated companies include the following:

- $506 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 LNG began making repayments in 2008 and is required to continue making repayments through full repayment of the loan in 2026. Repayment by Freeport LNG is supported by “process-or-pay” capacity service payments made by us to Freeport LNG under our terminal use agreement. See Note 4—Variable Interest Entities (VIEs), for additional information.

- $1,005 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 is 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 8—Suspended Wells

The following table reflects the net changes in suspended exploratory well costs during 2013, 2012 and 2011:

	Millions of Dollars		
	2013	2012	2011
Beginning balance at January 1	$ **1,038**	1,037	1,013
Additions pending the determination of proved reserves	**466**	185	96
Reclassifications to proved properties	**(29)**	(144)	(72)
Sales of suspended well investment	**(481)**	(18)	-
Charged to dry hole expense	**-**	(22)	-
Ending balance at December 31	$ **994 ***	1,038 **	1,037

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

The following table provides an aging of suspended well balances at December 31, 2013, 2012 and 2011:

	Millions of Dollars		
	2013	2012	2011
Exploratory well costs capitalized for a period of one year or less	$ **437**	186	115
Exploratory well costs capitalized for a period greater than one year	**557**	852	922
Ending balance	$ **994 ***	1,038 **	1,037
Number of projects with exploratory well costs capitalized for a period greater than one year	**29**	35	40

**Includes$57 million of assets held for sale in Nigeria.*
***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 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, 2013:

	Millions of Dollars			
		Suspended Since		
	Total	2010–2012	2007–2009	2002–2006
Alpine Satellite—Alaska[2]	23	-	-	23
Browse Basin—Australia[1]	18	13	5	-
Caldita/Barossa—Australia[1]	77	-	-	77
Clair SW—UK[1]	15	15	-	-
Fiord West—Alaska[2]	16	-	16	-
Muskwa—Canada[1]	54	54	-	-
NPR-A—Alaska[2]	17	-	17	-
Nza—Nigeria[2][3]	12	12	-	-
Pisagan—Malaysia[2]	10	-	-	10
Saleski—Canada[1]	17	-	17	-
Shenandoah—Lower 48[1]	43	-	43	-
Sunrise 3—Australia[2]	13	-	13	-
Surmont 3 and beyond—Canada[1]	63	37	18	8
Thornbury—Canada[1]	19	-	19	-
Tiber—Lower 48[1]	40	-	40	-
Ubah—Malaysia[2]	36	11	25	-
Uge—Nigeria[2][3]	45	15	16	14
Other of $10 million or less each[1][2]	39	9	13	17
Total	$ 557	166	242	149

(1)Additional appraisal wells planned.
(2)Appraisal drilling complete; costs being incurred to assess development.
(3)Assets held for sale as of December 31, 2013, and December 31, 2012.

Note 9—Impairments

During 2013, 2012 and 2011, we recognized the following before-tax impairment charges:

	Millions of Dollars		
	2013	2012	2011
Alaska	**$ 3**	3	2
Lower 48 and Latin America	**2**	192	71
Canada	**216**	262	253
Europe	**301**	211	(37)
Asia Pacific and Middle East	**3**	4	-
Corporate	**4**	8	32
	$ 529	680	321

2013

In 2013, we recorded property impairments of $216 million in our Canada segment, mainly as a result of lower natural gas price assumptions, reduced volume forecasts and higher costs.

In Europe, we recorded impairments of $301 million, primarily due to ARO revisions for properties in the United Kingdom which are nearing the end of their useful lives or have ceased production.

2012
In 2012, we recorded a $192 million property impairment in the Lower 48 and Latin America segment related to the planned disposition of the majority of our producing zones in the 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.

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.

Note 10—Asset Retirement Obligations and Accrued Environmental Costs

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

	Millions of Dollars	
	2013	2012
Asset retirement obligations	**$ 10,076**	9,164
Accrued environmental costs	**348**	364
Total asset retirement obligations and accrued environmental costs	**10,424**	9,528
Asset retirement obligations and accrued environmental costs due within one year*	**(541)**	(581)
Long-term asset retirement obligations and accrued environmental costs	**$ 9,883**	8,947

** Classified as a current liability on the balance sheet under "Other accruals" and includes $14 million and $158 million of liabilities associated with assets held for sale at December 31, 2013 and 2012, respectively.*

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 retirement obligations 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 2013 and 2012, our overall asset retirement obligation changed as follows:

	Millions of Dollars	
	2013	2012
Balance at January 1	**$ 9,164**	8,920
Accretion of discount	**434**	412
New obligations	**410**	315
Changes in estimates of existing obligations	**707**	543
Spending on existing obligations	**(298)**	(319)
Property dispositions	**(163)**	(607)
Foreign currency translation	**(178)**	281
Separation of Downstream business	**-**	(381)
Balance at December 31	**$ 10,076**	9,164

Accrued Environmental Costs
Total accrued environmental costs at December 31, 2013 and 2012, were $348 million and $364 million, respectively.

We had accrued environmental costs of $271 million and $279 million at December 31, 2013 and 2012, respectively, related to remediation activities in the United States and Canada. We had also accrued in Corporate and Other $60 million and $70 million of environmental costs associated with sites no longer in operation at December 31, 2013 and 2012, respectively. In addition, $17 million and $15 million were included at both December 31, 2013 and 2012, 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.

Expected expenditures for environmental obligations acquired in various business combinations are discounted using a weighted-average 5 percent discount factor, resulting in an accrued balance for acquired environmental liabilities of $124 million at December 31, 2013. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $19 million in 2014, $18 million in 2015, $10 million in 2016, $6 million in 2017, $4 million in 2018, and $82 million for all future years after 2018.

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Note 11—Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2013	2012
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
7.65% Debentures due 2023	**88**	88
7.625% Debentures due 2013	**-**	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
5.20% Notes due 2018	**500**	500
4.75% Notes due 2014	**400**	400
4.60% Notes due 2015	**1,500**	1,500
2.4% Notes due 2022	**1,000**	1,000
1.05% Notes due 2017	**1,000**	1,000
Commercial paper at 0.20% – 0.25% during 2013 and 0.15% – 0.33% during 2012	**961**	1,055
Industrial Development Bonds due 2013 through 2038 at 0.04% – 0.25% during 2013 and 0.04% – 0.35% during 2012	**18**	18
Marine Terminal Revenue Refunding Bonds due 2031 at 0.04% – 0.26% during 2013 and 0.04% – 0.35% during 2012	**265**	265
Other	**24**	24
Debt at face value	**20,336**	21,280
Capitalized leases	**922**	16
Net unamortized premiums and discounts	**404**	429
Total debt	**21,662**	21,725
Short-term debt	**(589)**	(955)
Long-term debt	$ **21,073**	20,770

Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2014 through 2018 are: $589 million, $1,576 million, $2,202 million, $1,073 million and $873 million, respectively. At December 31, 2013, we classified $861 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 facility.

During 2013, the following debt instruments were repaid at maturity:

- The $100 million 7.625% Debentures due 2013.
- The $750 million 5.50% Notes due 2013.

In February 2014, the $400 million 4.75% Notes due 2014 were repaid at maturity.

At December 31, 2013, 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 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 supported by our $7.5 billion revolving credit facility: 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 program, which is used to fund commitments relating to QG3. Commercial paper maturities are generally limited to 90 days.

At both December 31, 2013 and 2012, we had no direct outstanding borrowings under the revolving credit facility, with no letters of credit as of December 31, 2013. In addition, under the ConocoPhillips Qatar Funding Ltd. commercial paper program, there was $961 million of commercial paper outstanding at December 31, 2013, compared with $1,055 million at December 31, 2012. Since we had $961 million of commercial paper outstanding and had issued no letters of credit, we had access to $6.5 billion in borrowing capacity under our revolving credit facility at December 31, 2013.

During the second quarter of 2013, a lease of a semi-submersible floating production system (FPS) commenced for the Gumusut development, located in Malaysia, in which we are a co-venturer. The FPS lease provides for an initial noncancelable term of 15 years, a subsequent 5-year cancelable term with no required lease payments, and an additional 5-year term with terms and conditions to be agreed at a later date. The lease has no ongoing purchase options or escalation clauses. Certain contingent rental payments may be incurred if actual commissioning costs exceed provisioned amounts. The lease does not impose any significant restrictions concerning dividends, debt or further leasing activities.

A capital lease asset and capital lease obligation were recognized for our proportionate interest in the FPS of $906 million, based on the present value of the future minimum lease payments using our pre-tax incremental borrowing rate of 3.58 percent for debt with similar terms. As of December 31, 2013, the value of the lease asset and associated obligation is $906 million with commissioning activities continuing. Following the startup of the FPS, the capital lease asset will be depreciated over a period consistent with the estimated proved reserves of Gumusut using the unit-of-production method with the associated depreciation included in the "Depreciation, depletion and amortization" line on our consolidated income statement.

At December 31, 2013, future minimum payments due under capital leases were:

		Millions of Dollars
2014	$	127
2015		80
2016		80
2017		80
2018		80
Remaining years		769
Total		1,216
Less: portion representing imputed interest		(294)
Capital lease obligations	$	922

Note 12—Joint Venture Acquisition Obligation

We were 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. The principal portion of these payments totaled $772 million in 2013. In December 2013, we paid the remaining balance of the obligation, which totaled $2,810 million and is included in the “Other” line in the financing activities section of our consolidated statement of cash flows. Interest accrued 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, 2013, 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, 2013, 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 2013 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 3 years. Our maximum potential amount of future payments related to this guarantee is approximately $130 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 tests with milestones, which we estimate would occur beginning in 2016. Our maximum exposure at December 31, 2013, is $2.8 billion based upon our pro-rata share of the facility used at that date. At December 31, 2013, 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 3 to 18 years. Our maximum potential amount of future payments, or cost of volume delivery, under these guarantees is estimated to be $0.8 billion ($1.9 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 32 years or the life of the venture. Our maximum potential amount of future payments related to these guarantees is approximately $170 million and would become payable if APLNG does not perform.

Other Guarantees
We have other guarantees with maximum future potential payment amounts totaling approximately $260 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, a guarantee for our portion of a joint venture's debt obligations and a guarantee of minimum charter revenue for an LNG vessel. These guarantees have remaining terms of up to 10 years or the life of the venture and would become payable if, upon sale, certain asset values are lower than guaranteed amounts, business conditions decline at guaranteed entities, or as a result of non-performance of contractual terms by guaranteed parties.

Indemnifications
Over the years, we have entered into agreements to sell ownership interests in certain corporations, joint ventures and assets that gave rise to qualifying indemnifications. These agreements include indemnifications for taxes, environmental liabilities, employee claims, 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, 2013, was approximately $60 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 at December 31, 2013 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. This agreement provided 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 arising in the ordinary course of business have been made against ConocoPhillips. 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. With respect to 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 other 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 agency 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 and international 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.

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, 2013, we had performance obligations secured by letters of credit of $827 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. On September 3, 2013, an ICSID arbitration tribunal held that Venezuela unlawfully expropriated ConocoPhillips’ significant oil investments in June 2007. A separate arbitration phase will proceed to determine the amount of damages owed to ConocoPhillips for Venezuela’s actions.

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 the ICSID tribunal, Ecuador confiscated the crude oil production of Burlington and its co-venturer and sold the 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 supplemental counterclaims 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 is now proceeding to determine the damages owed to ConocoPhillips for Ecuador’s actions and to address Ecuador’s counterclaims.

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. As of December 2013, ConocoPhillips paid, under protest, tax assessments totaling approximately $232 million, which are primarily recorded in the “Investments and long-term receivables” line on our 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: 2014—$125 million; 2015—$117 million; 2016—$25 million; 2017—$25 million; 2018—$22 million; and 2019 and after—$121 million. Total payments under the agreements were $127 million in 2013, $130 million in 2012 and $429 million in 2011.

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.

Our derivative instruments are held at fair value on our consolidated balance sheet. Where these balances have the right of setoff, they are presented on a net basis. Related cash flows are recorded as operating activities on the consolidated statement of cash flows. On our 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	
	2013	2012
Assets		
Prepaid expenses and other current assets	$ **871**	1,538
Other assets	**64**	105
Liabilities		
Other accruals	**890**	1,509
Other liabilities and deferred credits	**58**	99

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

	Millions of Dollars		
	2013	2012	2011
Sales and other operating revenues	$ **(160)**	(291)	907
Other income	**4**	(1)	(9)
Purchased commodities	**139**	214	(729)

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

	Open Position Long/(Short)	
	2013	2012
Commodity		
Natural gas and power (billions of cubic feet equivalent)		
Fixed price	**(18)**	(48)
Basis	**(10)**	125

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 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	
	2013	2012
Assets		
Prepaid expenses and other current assets	**$ 1**	32
Liabilities		
Other accruals	**-**	2
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		
	2013	2012	2011
Foreign currency transaction (gains) losses	**$ 4**	(138)	(9)

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

		In Millions Notional Currency	
		2013	2012
Foreign Currency Exchange Derivatives			
Sell U.S. dollar, buy British pound	USD	**-**	2,573
Buy U.S. dollar, sell other currencies*	USD	**6**	140
Buy British pound, sell euro	GPB	**17**	-
Buy euro, sell British pound	EUR	**-**	96

**PrimarilyCanadian 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:

	Millions of Dollars			
	Carrying Amount			
	Cash and Cash Equivalents		Short-Term Investments	
	2013	2012	**2013**	2012
Cash	**$ 636**	829	**-**	-
Time Deposits				
Remaining maturities from 1 to 90 days	**5,336**	2,789	**137**	-
Commercial Paper				
Remaining maturities from 1 to 90 days	**274**	-	**135**	-
	$ 6,246	3,618	**272**	-

In conjunction with the separation of our Downstream business, we received a special cash distribution from Phillips 66. See Note 3—Discontinued Operations, for additional information. The balance of the special cash distribution was zero at December 31, 2013, and $748 million at December 31, 2012, and was included in "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, 2013 and December 31, 2012, was $57 million and $130 million, respectively. For these instruments, no collateral was posted as of December 31, 2013 or December 31, 2012. If our credit rating had been lowered one level from its “A” rating (per Standard and Poor’s) on December 31, 2013, we would be required to post no additional collateral to our counterparties. If we had been downgraded below investment grade, we would be required to post $57 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 during 2013 and 2012.

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 for all periods presented.

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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, 2013					December 31, 2012			
		Level 1	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	Total
Assets									
Deferred compensation investments	**$**	**306**	**-**	**-**	**306**	305	-	-	305
Commodity derivatives		**744**	**177**	**10**	**931**	1,052	567	18	1,637
Total assets	**$**	**1,050**	**177**	**10**	**1,237**	1,357	567	18	1,942
Liabilities									
Commodity derivatives	**$**	**765**	**172**	**7**	**944**	1,031	567	4	1,602
Total liabilities	**$**	**765**	**172**	**7**	**944**	1,031	567	4	1,602

The following table summarizes those commodity derivative balances subject to the right of setoff as presented on our consolidated balance sheet:

	Millions of Dollars					
		Gross Amounts Recognized	Gross Amounts Offset	Net Amounts Excluding Collateral	Cash Collateral	Net Amounts Subject to Setoff
December 31, 2013						
Assets	**$**	**919**	**827**	**92**	**6**	**86**
Liabilities		**935**	**827**	**108**	**26**	**82**
December 31, 2012						
Assets	$	1,621	1,403	218	29	189
Liabilities		1,588	1,403	185	16	169

At December 31, 2013 and December 31, 2012, we did not present any amounts gross on our consolidated balance sheet where we had the right of setoff.

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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, 2013					
Net PP&E (held for use)		**117**	**-**	**117**	**488**
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

**Representsthe fair value at the time of the impairment.*

Net PP&E (held for use)

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.

Net PP&E (held for sale)

In 2012, 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.

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 7—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 at December 31, 2012, was estimated based on the net present value of the future cash flows as a Level 2 fair value with an effective yield rate of 0.7 percent, based on yields of U.S. Treasury securities of similar average duration adjusted for our average credit risk spread and the amortizing nature of the obligation principal. See Note 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	
	2013	2012	**2013**	2012
Financial assets				
Deferred compensation investments	$ **306**	305	**306**	305
Commodity derivatives	**99**	221	**99**	221
Total loans and advances—related parties	**1,528**	1,697	**1,680**	1,916
Financial liabilities				
Total debt, excluding capital leases	**20,740**	21,709	**23,553**	26,349
Total joint venture acquisition obligation	**-**	3,582	**-**	3,968
Commodity derivatives	**92**	199	**92**	199

At December 31, 2013, commodity derivative assets and liabilities appear net of $6 million of obligations to return cash collateral and $26 million of rights to reclaim cash collateral, respectively. 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.

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		
	2013	2012	2011
Issued			
Beginning of year	**1,762,247,949**	1,749,550,587	1,740,529,279
Distributed under benefit plans	**5,921,957**	12,697,362	9,021,308
End of year	**1,768,169,906**	1,762,247,949	1,749,550,587
Held in Treasury			
Beginning of year	**542,230,673**	463,880,628	272,873,537
Repurchase of common stock	**-**	79,904,400	155,453,382
Distributed under benefit plans	**-**	(1,554,355)	(475,696)
Transfer from grantor trust	**-**	-	36,029,405
End of year	**542,230,673**	542,230,673	463,880,628
Held in Grantor Trusts			
Beginning of year	**-**	-	36,890,375
Repurchase of common stock	**-**	-	(157,470)
Distributed under benefit plans	**-**	-	(703,500)
Transfer to treasury stock	**-**	-	(36,029,405)
End of year	**-**	-	-

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, 2013 or 2012.

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Noncontrolling Interests

At December 31, 2013 and 2012, we had $402 million and $440 million outstanding, respectively, of equity in less-than-wholly owned consolidated subsidiaries held by noncontrolling interest owners. For both periods, the amounts were related to the Darwin LNG and Bayu-Darwin Pipeline operating joint ventures we control, located in Australia's Northern Territory.

Note 18—Non-Mineral Leases

The company primarily leases drilling equipment and office buildings, as well as ocean transport vessels, tugboats, barges, corporate aircraft, computers 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. For additional information on leased assets under capital leases, see Note 11—Debt.

At December 31, 2013, future minimum rental payments due under noncancelable leases were:

	Millions of Dollars
2014	$ 602
2015	519
2016	483
2017	318
2018	182
Remaining years	645
Total	2,749
Less: income from subleases	(19)
Net minimum operating lease payments	$ 2,730

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

	Millions of Dollars		
	2013	2012	2011
Total rentals*	**$ 317**	282	304
Less: sublease rentals	**(12)**	(15)	(14)
	$ 305	267	290

**Includes $3 million and $29 million of contingent rentals in 2012 and 2011, respectively. Contingent rentals were primarily related to drilling equipment and based on usage.*

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Note 19—Employee Benefit Plans

Pension and Postretirement Plans

In connection with the separation of the Downstream business in 2012, ConocoPhillips entered into an Employee Matters Agreement with Phillips 66, 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	
		2013		2012		**2013**	2012
		U.S.	**Int'l.**	U.S.	Int'l.		
Change in Benefit Obligation							
Benefit obligation at January 1	$	**4,225**	**3,438**	6,175	3,484	**765**	926
Service cost		**138**	**102**	170	91	**3**	6
Interest cost		**143**	**145**	186	152	**26**	33
Plan participant contributions		**-**	**6**	-	7	**22**	23
Separation of Downstream business		**-**	**-**	(2,464)	(653)	**-**	(199)
Actuarial (gain) loss		**(205)**	**72**	735	297	**(57)**	47
Benefits paid		**(347)**	**(110)**	(577)	(113)	**(75)**	(72)
Foreign currency exchange rate change		**-**	**(70)**	-	173	**(2)**	1
Benefit obligation at December 31*	$	**3,954**	**3,583**	4,225	3,438	**682**	765
**Accumulated benefit obligation portion of above at December 31:*	*$*	***3,516***	***2,798***	*3,710*	*2,972*		
Change in Fair Value of Plan Assets							
Fair value of plan assets at January 1	$	**2,732**	**2,760**	4,149	2,722	**-**	-
Actual return on plan assets		**505**	**315**	509	267	**-**	-
Company contributions		**202**	**198**	363	204	**53**	49
Plan participant contributions		**-**	**6**	-	7	**22**	23
Separation of Downstream business		**-**	**-**	(1,712)	(479)	**-**	-
Benefits paid		**(347)**	**(110)**	(577)	(113)	**(75)**	(72)
Foreign currency exchange rate change		**-**	**(37)**	-	152	**-**	-
Fair value of plan assets at December 31	$	**3,092**	**3,132**	2,732	2,760	**-**	-
Funded Status	$	**(862)**	**(451)**	(1,493)	(678)	**(682)**	(765)

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	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2013		2012		**2013**	2012
	U.S.	**Int'l.**	U.S.	Int'l.		
Amounts Recognized in the Consolidated Balance Sheet at December 31						
Noncurrent assets	$ **-**	**128**	-	94	**-**	-
Current liabilities	**(35)**	**(8)**	(21)	(8)	**(53)**	(54)
Noncurrent liabilities	**(827)**	**(571)**	(1,472)	(764)	**(629)**	(711)
Total recognized	$ **(862)**	**(451)**	(1,493)	(678)	**(682)**	(765)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**4.40 %**	**4.75**	3.55	4.50	**4.45**	3.55
Rate of compensation increase	**4.75**	**4.60**	4.75	4.45	**-**	-
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount rate	**3.55 %**	**4.50**	4.00	4.95	**3.55**	4.25
Expected return on plan assets	**7.00**	**6.00**	7.00	6.10	**-**	-
Rate of compensation increase	**4.75**	**4.45**	4.50	4.50	**-**	-

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	
	2013		2012		**2013**	2012
	U.S.	**Int'l.**	U.S.	Int'l.		
Unrecognized net actuarial loss (gain)	$ **767**	**578**	1,509	758	**(31)**	29
Unrecognized prior service cost (credit)	**22**	**(54)**	28	(60)	**(8)**	(12)

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	Millions of Dollars							
	Pension Benefits					Other Benefits	
	2013			2012		**2013**	2012
		U.S.	**Int'l.**	U.S.	Int'l.		
Sources of Change in Other Comprehensive Income							
Net gain (loss) arising during the period	**$**	**524**	**107**	(450)	(206)	**57**	(48)
Separation of Downstream business		**-**	**-**	810	94	**-**	(7)
Amortization of loss included in income*		**218**	**73**	371	59	**3**	-
Net change during the period	**$**	**742**	**180**	731	(53)	**60**	(55)
Prior service credit arising during the period	**$**	**-**	**1**	-	2	**-**	-
Separation of Downstream business		**-**	**-**	17	(12)	**-**	3
Amortization of prior service cost (credit) included in income		**6**	**(7)**	7	(8)	**(4)**	(4)
Net change during the period	**$**	**6**	**(6)**	24	(18)	**(4)**	(1)

**Includes settlement losses recognized during the period.*

Amounts included in accumulated other comprehensive income at December 31, 2013, that are expected to be amortized into net periodic benefit cost during 2014 are provided below:

	Millions of Dollars			
	Pension Benefits			Other Benefits
		U.S.	Int'l.	
Unrecognized net actuarial loss (gain)	$	76	58	(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 $6,011 million, $5,393 million, and $5,151 million, respectively, at December 31, 2013, and $6,278 million, $5,602 million, and $4,537 million, respectively, at December 31, 2012.

For our unfunded nonqualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $581 million and $392 million, respectively, at December 31, 2013, and were $525 million and $382 million, respectively, at December 31, 2012.

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		
	2013		2012		2011		**2013**	2012	2011
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.			
Components of Net Periodic Benefit Cost									
Service cost	**$ 138**	**102**	170	91	225	98	**3**	6	10
Interest cost	**143**	**145**	186	152	247	178	**26**	33	42
Expected return on plan assets	**(186)**	**(160)**	(223)	(158)	(280)	(175)	**-**	-	-
Amortization of prior service cost (credit)	**6**	**(7)**	7	(8)	9	-	**(4)**	(4)	(7)
Recognized net actuarial loss (gain)	**151**	**73**	191	59	165	46	**3**	-	(5)
Settlements	**67**	**-**	181	-	21	-	**-**	-	-
Net periodic benefit cost	**$ 319**	**153**	512	136	387	147	**28**	35	40

We recognized pension settlement losses of $67 million in 2013, $181 million (including $24 million in discontinued operations) in 2012 and $21 million in 2011. In 2013 and 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 7.25 percent in 2013 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, 2013 and 2012.

- Fair values of equity securities and government debt securities categorized in Level 1 are primarily based on quoted market prices in active markets for identical assets and liabilities.
- 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 for similar assets and liabilities in active markets and for identical assets and liabilities in markets that are not active. 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 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, 2013, the participating interest in the annuity contract was valued at $110 million and consisted of $312 million in debt securities, less $202 million for the accumulated benefit obligation covered by the contract. 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. The net change from 2012 to 2013 is due to a decrease in the fair value of the underlying investments of $46 million and a decrease in the present value of the contract obligation of $23 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
2013								
Equity Securities								
U.S.	**$ 1,018**	**-**	**-**	**1,018**	**531**	**-**	**-**	**531**
International	**702**	**-**	**-**	**702**	**437**	**-**	**-**	**437**
Common/collective trusts	**-**	**529**	**-**	**529**	**-**	**217**	**-**	**217**
Mutual funds	**-**	**-**	**-**	**-**	**373**	**-**	**-**	**373**
Debt Securities								
Government	**106**	**69**	**-**	**175**	**557**	**-**	**-**	**557**
Corporate	**-**	**333**	**3**	**336**	**-**	**150**	**-**	**150**
Agency and mortgage-backed securities	**-**	**97**	**-**	**97**	**-**	**25**	**1**	**26**
Common/collective trusts	**-**	**-**	**-**	**-**	**-**	**356**	**-**	**356**
Mutual funds	**-**	**-**	**-**	**-**	**191**	**-**	**-**	**191**
Cash and cash equivalents	**-**	**123**	**-**	**123**	**30**	**17**	**-**	**47**
Private equity funds	**-**	**-**	**1**	**1**	**-**	**-**	**21**	**21**
Derivatives	**(1)**	**2**	**-**	**1**	**19**	**12**	**-**	**31**
Real estate	**-**	**-**	**-**	**-**	**-**	**-**	**190**	**190**
Total*	**$ 1,825**	**1,153**	**4**	**2,982**	**2,138**	**777**	**212**	**3,127**

**Excludes the participating interest in the insurance annuity contract with a net asset value of $110 million and net receivables related to security transactions of $5 million.*

	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 3 activity was not material for all periods.

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 2014, we expect to contribute approximately $350 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.

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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.	
2014	$ 402	117	61
2015	361	121	62
2016	362	123	62
2017	366	134	62
2018	400	137	62
2019–2023	1,965	791	294

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, subject to statutory limits, in the thrift feature of the CPSP to a choice of approximately 37 investment funds. Starting in 2013, employees who participate in the CPSP and contribute 1 percent of their eligible pay receive a 9 percent Company cash match, subject to certain limitations. Prior to 2013, 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 $101 million in 2013, $16 million in 2012, and $25 million in 2011.

The stock savings feature of the CPSP was a leveraged employee stock ownership plan; however, beginning in 2013, the CPSP no longer has a stock savings feature. Prior to 2013, 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 (subsequently the stock savings feature of the CPSP) borrowed funds that were used to purchase previously unissued shares of Company common stock. Since the Company guaranteed the CPSP's borrowings, the unpaid balance was reported as a liability of the Company and unearned compensation was shown as a reduction of common stockholders' equity. Dividends on all shares were charged against retained earnings. The debt was 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 were 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. The total number of allocated CPSP stock savings feature shares as of December 31, 2013 and 2012, were 9,280,837 and 11,246,660, respectively.

With the stock savings feature, we recognized 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 for the stock savings feature of $104 million and $77 million in 2012 and 2011, 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. In 2011, we contributed 660,775 shares of Company common stock from the Compensation and Benefits Trust. The shares had a fair value of $84 million. 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 and $45 million in 2012 and 2011, respectively. These dividends reduced the amount of compensation expense recognized in each period. Interest incurred on the CPSP debt in 2012 and 2011 was $0.1 million and $1 million, respectively.

We have several defined contribution plans for our international employees, each with its own terms and eligibility depending on location. Total compensation expense related to continuing and discontinued operations recognized for these international plans was approximately $60 million in 2013 and $56 million in both 2012 and 2011.

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. The Human Resources and Compensation Committee of our Board of Directors is authorized to determine the types, terms, conditions, and limitations of awards granted. Awards may be granted in the form of, but not limited to, stock options, restricted stock units, and performance share units to employees and nonemployee directors who contribute to the Company's continued success and profitability.

Total share-based compensation expense is measured using the grant date fair value for our equity-classified awards and the settlement date fair value for our liability-classified awards. 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. 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. 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, which provided 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:

- 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.

- Nonexercisable stock options and restricted stock units were converted to those of the entity where the employee holding them was 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 Phillips 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 for the year ended December 31, 2012, or the number of potentially dilutive securities as of December 31, 2012, 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		
	2013	2012	2011
Compensation cost	$ **308**	321	246
Tax benefit	**109**	118	86

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 ConocoPhillips common 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 six months of the grant date, but those options do not become exercisable until the end of the normal vesting period.

The fair market values of the options granted over the past three years were measured on the date of grant using the Black-Scholes-Merton option-pricing model. The weighted-average assumptions used were as follows:

	2013	2012	2011
Assumptions used			
Risk-free interest rate	**1.09 %**	1.62	3.10
Dividend yield	**4.00 %**	4.00	4.00
Volatility factor	**28.95 %**	33.30	33.40
Expected life (years)	**5.95**	7.42	6.87

There were no ranges in the assumptions used to determine the fair market values of our options granted over the past three years.

For 2012 and 2011, expected volatility 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. Due to the separation of our Downstream business in 2012, expected volatility for grants of options in 2013 was based on a three-year average historical stock price volatility of a group of peer companies. We believe our historical volatility for periods prior to the separation of our Downstream business is no longer relevant in estimating expected volatility.

The following summarizes our stock option activity for the year ended December 31, 2013:

	Options	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Millions of Dollars Aggregate Intrinsic Value
Outstanding at December 31, 2012	16,297,005	$ 43.67		
Granted	**3,109,800**	**58.08**	**$ 9.90**	
Exercised	**(3,078,576)**	**33.45**		**$ 95**
Forfeited	**-**	**-**		
Expired or canceled	**(13,139)**	**60.53**		
Outstanding at December 31, 2013	**16,315,090**	**$ 48.33**		
Vested at December 31, 2013	**13,418,902**	**$ 46.42**		**$ 320**
Exercisable at December 31, 2013	**11,600,659**	**$ 44.88**		**$ 294**

The weighted-average remaining contractual term of vested options and exercisable options at December 31, 2013, was 5.10 years and 4.57 years, respectively. The weighted-average grant date fair value of stock option awards granted during 2012 and 2011 was $15.69 and $16.70, respectively. The aggregate intrinsic value of options exercised during 2012 and 2011 was $469 million and $416 million, respectively.

During 2013, we received $103 million in cash and realized a tax benefit related to both continuing and discontinued operations of $47 million from the exercise of options. At December 31, 2013, the remaining unrecognized compensation expense from unvested options was $17 million, which will be recognized over a weighted-average period of 1.84 years, the longest period being 2.10 years.

Stock Unit Program—Generally, restricted stock units are granted annually under the provisions of the Plan. Restricted stock units granted prior to 2013 vest ratably in three equal annual installments beginning on the third anniversary of the grant date. Beginning in 2013, restricted stock units granted will vest in an aggregate installment on the third anniversary of the grant date. In addition, beginning in 2012, restricted stock units granted under the Plan for a variable long-term incentive program vest ratably in three equal annual installments beginning on the first anniversary of the grant date. 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 restricted stock units are settled by issuing one share of ConocoPhillips common stock per unit. Units awarded to retirement eligible employees vest six months from the grant date; however, those units are not issued as common stock until the earlier of separation from the Company or the end of the regularly scheduled vesting period. Until issued as stock, most recipients of the restricted stock units receive a quarterly cash payment of a dividend equivalent that is charged to retained earnings. The grant date fair market value of these restricted stock units is deemed equal to the average ConocoPhillips stock price on the grant date. 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, 2013:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2012	11,477,122	$ 46.58	
Granted	**4,881,483**	**57.99**	
Forfeited	**(364,716)**	**51.38**	
Issued	**(3,832,737)**		**$ 245**
Outstanding at December 31, 2013	**12,161,152**	**$ 51.37**	
Not Vested at December 31, 2013	**8,626,833**	**$ 52.66**	

At December 31, 2013, the remaining unrecognized compensation cost from the unvested units was $307 million, which will be recognized over a weighted-average period of 2.18 years, the longest period being 6.33 years. The weighted-average grant date fair value of stock unit awards granted during 2012 and 2011 was $60.62 and $67.54, respectively. The total fair value of stock units issued during 2012 and 2011 was $187 million and $109 million, respectively.

Performance Share Program—Under the Plan, we also annually grant restricted performance share units (PSUs) to senior management. These PSUs are authorized three years prior to their effective grant date (the performance period). Compensation expense is initially measured using the average fair market value of ConocoPhillips common stock and is subsequently adjusted, based on changes in the ConocoPhillips stock price through the end of each subsequent reporting period, through the grant date for stock-settled awards and the settlement date for cash-settled awards.

Stock-Settled

For performance periods beginning before 2009, PSUs do not vest until the employee becomes eligible for retirement by reaching age 55 with five years of service, and restrictions do not lapse until the employee separates from the Company. With respect to awards for performance periods beginning in 2009 through 2012, PSUs do not vest until the earlier of the date the employee becomes eligible for retirement by reaching age 55 with five years of service or five years after the grant date of the award, and restrictions do not lapse until the earlier of the employee’s separation from the Company or five years after the grant date (although recipients can elect to defer the lapsing of restrictions until separation). We recognize compensation expense for these awards beginning on the grant date 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 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. Until issued as stock, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to retained earnings. Beginning in 2013, PSUs authorized for future grants will vest, absent employee election to defer, upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending on the conclusion of the performance period. PSUs are settled by issuing one share of ConocoPhillips common stock per unit.

The following summarizes our stock-settled Performance Share Program activity for the year ended December 31, 2013:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2012	5,184,284	$ 51.54	
Granted	**7,650**	**60.00**	
Forfeited	**-**	**-**	
Issued	**(290,748)**		**$ 18**
Outstanding at December 31, 2013	**4,901,186**	**$ 51.60**	
Not Vested at December 31, 2013	**1,150,628**	**$ 52.83**	

At December 31, 2013, the remaining unrecognized compensation cost from unvested stock-settled performance share awards was $30 million, which includes $7 million related to unvested stock-settled performance share awards tied to Phillips 66 stock held by ConocoPhillips employees, which will be recognized over a weighted-average period of 3.35 years, the longest period being 7.18 years. The weighted-average grant date fair value of stock-settled performance share units granted during 2012 and 2011 was $74.16 and $70.57, respectively. The total fair value of stock-settled PSUs issued during 2012 and 2011 was $71 million and $37 million, respectively.

Cash-Settled

In connection with and immediately following the separation of our Downstream business in 2012, new performance share units, subject to a shortened performance period, were authorized to be granted. Once granted, these PSUs vest, absent employee election to defer, on the earlier of five years after the grant date of the award or the date the employee becomes eligible for retirement. For employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. Otherwise, we recognize compensation expense beginning on the grant date and ending on the date the PSUs are scheduled to vest. These PSUs are settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and thus are classified as liabilities on the balance sheet. Until settlement occurs, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to compensation expense.

Beginning in 2013, PSUs authorized for future grants will vest upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending on the conclusion of the performance period. These PSUs will be settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and are classified as liabilities on the balance sheet.

The following summarizes our cash-settled Performance Share Program activity for the year ended December 31, 2013:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2012	-	$ -	
Granted	**128,567**	**58.08**	
Forfeited	**-**	**-**	
Settled	**(3,791)**		**$ -**
Outstanding at December 31, 2013	**124,776**	**$ 58.08**	
Not Vested at December 31, 2013	**82,793**	**$ 58.08**	

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At December 31, 2013, the remaining unrecognized compensation cost from unvested cash-settled performance share awards was $4 million, which will be recognized over a weighted-average period of 3.13 years, the longest period being 4.10 years. There were no cash-settled performance share awards granted, issued or outstanding as of December 31, 2012 or 2011.

From inception of the Performance Share Program through 2013, approved PSU awards were granted after the conclusion of performance periods. Beginning in February 2014, initial target PSU awards will be issued near the beginning of new performance periods. These initial target PSU awards will terminate at the end of the performance periods and will be settled after the performance periods have ended. Also in 2014, initial target PSU awards will be issued for open performance periods that began in prior years. For the open performance period beginning in 2012, the initial target PSU awards will terminate at the end of the three-year performance period and will be replaced with approved PSU awards. For the open performance period beginning in 2013, the initial target PSU awards will terminate at the end of the three-year performance period and will be settled after the performance period has ended. There is no effect on recognition of compensation expense.

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, 2013:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2012	1,132,556	$ 27.34	
Granted	**76,920**	**62.52**	
Forfeited	**(3,458)**	**20.22**	
Issued	**(33,417)**		**$ 2**
Outstanding at December 31, 2013	**1,172,601**	**$ 29.31**	
Not Vested at December 31, 2013	**-**		

At December 31, 2013, 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 awards granted during 2012 and 2011 was $63.54 and $70.25, respectively. The total fair value of awards issued during 2012 and 2011 was $73 million and $10 million, respectively.

Note 20—Income Tax

Income taxes charged to income from continuing operations were:

	Millions of Dollars		
	2013	2012	2011
Income Taxes			
Federal			
Current	$ **724**	63	1,066
Deferred	**811**	624	285
Foreign			
Current	**4,249**	6,255	6,400
Deferred	**504**	744	48
State and local			
Current	**220**	231	308
Deferred	**(99)**	25	101
	$ **6,409**	7,942	8,208

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	
	2013	2012
Deferred Tax Liabilities		
PP&E and intangibles	$ **20,079**	18,826
Investment in joint ventures	**943**	872
Inventory	**86**	76
Partnership income deferral	**168**	343
Other	**724**	793
Total deferred tax liabilities	**22,000**	20,910
Deferred Tax Assets		
Benefit plan accruals	**1,274**	1,760
Asset retirement obligations and accrued environmental costs	**4,483**	3,954
Deferred state income tax	**49**	77
Other financial accruals and deferrals	**297**	544
Loss and credit carryforwards	**1,487**	2,062
Other	**267**	398
Total deferred tax assets	**7,857**	8,795
Less: valuation allowance	**(969)**	(1,345)
Net deferred tax assets	**6,888**	7,450
Net deferred tax liabilities	$ **15,112**	13,460

Current assets, long-term assets, current liabilities and long-term liabilities included deferred taxes of $703 million, $171 million, $766 million and $15,220 million, respectively, at December 31, 2013, and $461 million, $222 million, $958 million and $13,185 million, respectively, at December 31, 2012.

We have loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2015 and 2034 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 2013, valuation allowances decreased a total of $376 million. This primarily relates to a net utilization of loss carryforwards, a utilization of U.S. foreign tax credit carryforwards and relinquishment of assets. 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, 2013 and 2012, income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $3,222 million and $2,286 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 2013, 2012 and 2011:

	Millions of Dollars		
	2013	2012	2011
Balance at January 1	**$ 872**	1,071	1,125
Additions based on tax positions related to the current year	**52**	98	46
Additions for tax positions of prior years	**30**	48	145
Reductions for tax positions of prior years	**(251)**	(206)	(35)
Settlements	**(48)**	(108)	(206)
Lapse of statute	**-**	(31)	(4)
Balance at December 31	**$ 655**	872	1,071

Included in the balance of unrecognized tax benefits for 2013, 2012 and 2011 were $440 million, $650 million and $815 million, respectively, which, if recognized, would impact our effective tax rate.

At December 31, 2013, 2012 and 2011, accrued liabilities for interest and penalties totaled $120 million, $129 million and $141 million, respectively, net of accrued income taxes. Interest and penalties resulted in a benefit to earnings in 2013 of $9 million, a benefit to earnings in 2012 of $9 million, and a charge to earnings in 2011 of $10 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 (2010), Canada (2006), United States (2008) and Norway (2012). Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion in the many jurisdictions in which we operate around the world. As a consequence, the balance in unrecognized tax benefits can be expected to fluctuate from period to period. It is reasonably possible such changes could be significant when compared with our total unrecognized tax benefits, but the amount of change is not estimable.

The amounts of U.S. and foreign income from continuing operations before income taxes, with a reconciliation of tax at the federal statutory rate with the provision for income taxes, were:

	Millions of Dollars			Percent of Pretax Income		
	2013	2012	2011	**2013**	2012	2011
Income before income taxes from continuing operations						
United States	$ **5,046**	4,070	4,762	**34.9 %**	26.4	30.9
Foreign	**9,400**	11,353	10,634	**65.1**	73.6	69.1
	$ **14,446**	15,423	15,396	**100.0 %**	100.0	100.0
Federal statutory income tax	$ **5,056**	5,398	5,389	**35.0 %**	35.0	35.0
Foreign taxes in excess of federal statutory rate	**1,389**	2,878	2,658	**9.6**	18.6	17.3
Capital loss benefit	**(79)**	(461)	-	**(0.5)**	(3.0)	-
Federal manufacturing deduction	**(35)**	(52)	(73)	**(0.2)**	(0.3)	(0.5)
State income tax	**79**	166	266	**0.5**	1.1	1.7
Other	**(1)**	13	(32)	**-**	0.1	(0.2)
	$ **6,409**	7,942	8,208	**44.4 %**	51.5	53.3

The change in the effective tax rate from 2012 to 2013 was primarily due to lower income in high tax jurisdictions in 2013. 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.

Statutory tax rate changes did not have a significant impact on our income tax expense in 2013.

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.

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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, 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
Other comprehensive income (loss)	**601**	**-**	**(2,686)**	**-**	**(2,085)**
December 31, 2013	**$ (824)**	**-**	**2,826**	**-**	**2,002**

The following table summarizes reclassifications out of accumulated other comprehensive income during the year ended December 31, 2013:

	Millions of Dollars
	2013
Defined Benefit Plans	**$ 184**

Above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of $105 million for the year ended December 31, 2013. See Note 19—Employee Benefit Plans, for additional information.

There were no items within accumulated other comprehensive income related to noncontrolling interests.

Note 22—Cash Flow Information

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

	Millions of Dollars		
	2013	2012	2011
Noncash Investing and Financing Activities			
Increase in PP&E related to an increase in asset retirement obligations*	**$ 1,329**	1,010	182
Increase in PP&E and debt related to a capital lease asset and obligation	**906**	-	-
Cash Payments			
Interest	**$ 566**	724	919
Income taxes**	**4,910**	8,100	9,827
Net Sales (Purchases) of Short-Term Investments			
Short-term investments purchased	**$ (361)**	(497)	(6,744)
Short-term investments sold	**98**	1,094	7,144
	$ (263)	597	400

** Includes $212 million and $152 million in 2013 and 2012, respectively, primarily related to the impact of U.K. tax law changes on the deductibility of decommissioning costs.*
***2012 and 2011 have been revised to conform to current-year presentation to include only income tax payments related to continuing operations.*

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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		
	2013	2012	2011
Interest and Debt Expense			
Incurred			
Debt	**$ 1,087**	1,170	1,230
Other	**192**	154	212
	1,279	1,324	1,442
Capitalized	**(667)**	(615)	(488)
Expensed	**$ 612**	709	954
Other Income			
Interest income	**$ 113**	163	170
Other, net	**261**	306	94
	$ 374	469	264
Research and Development Expenditures—expensed	**$ 258**	221	193
Shipping and Handling Costs*	**$ 1,137**	1,338	1,394

**Amounts included in production and operating expenses.*

Foreign Currency Transaction (Gains) Losses—after-tax			
Alaska	**$ -**	-	-
Lower 48 and Latin America	**-**	-	-
Canada	**(6)**	5	(3)
Europe	**(31)**	21	7
Asia Pacific and Middle East	**(29)**	29	(23)
Other International	**2**	1	3
LUKOIL Investment	**-**	-	(1)
Corporate and Other	**31**	2	(16)
	$ (33)	58	(33)

	Millions of Dollars	
	2013	2012
Properties, Plants and Equipment		
Proved properties*	**$123,012**	111,458
Unproved properties*	**8,465**	8,257
Other	**6,671**	6,464
Gross properties, plants and equipment	**138,148**	126,179
Less: Accumulated depreciation	**(65,321)**	(58,916)
Net properties, plants and equipment	**$ 72,827**	67,263

** Excludes assets held for sale reclassified to prepaid expenses and other current assets, including proved and unproved properties of $1,773 million and $73 million, respectively, at December 31, 2013, and $11,075 million and $234 million, respectively, at December 31, 2012.*

Note 24—Related Party Transactions

We consider our equity method investments to be related parties. Significant transactions with related parties were:

	Millions of Dollars		
	2013	2012	2011
Operating revenues and other income	**$102**	59	49
Purchases	**184**	261	327
Operating expenses and selling, general and administrative expenses	**193**	183	233
Net interest expense*	**31**	38	61

* *We paid interest to, or received interest from, various affiliates, including FCCL Partnership. See Note 7—Investments, Loans and Long-Term Receivables and Note 12—Joint Venture Acquisition Obligation, 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 Nigeria and Algeria businesses and our interest in Kashagan. Accordingly, 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 3—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, costs associated with the separation and certain technology activities, including 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		
	2013	2012	2011
Sales and Other Operating Revenues			
Alaska	**$ 8,553**	9,502	9,533
Lower 48 and Latin America	**19,480**	19,600	23,507
Intersegment eliminations	**(104)**	(230)	(283)
Lower 48 and Latin America	**19,376**	19,370	23,224
Canada	**5,254**	5,028	6,270
Intersegment eliminations	**(607)**	(475)	(944)
Canada	**4,647**	4,553	5,326
Europe	**12,040**	14,709	17,119
Intersegment eliminations	**-**	(72)	(50)
Europe	**12,040**	14,637	17,069
Asia Pacific and Middle East	**8,426**	7,705	8,665
Intersegment eliminations	**-**	(41)	(1)
Asia Pacific and Middle East	**8,426**	7,664	8,664
Other International	**1,208**	2,088	221
Corporate and Other	**163**	153	159
Consolidated sales and other operating revenues	**$54,413**	57,967	64,196
Depreciation, Depletion, Amortization and Impairments			
Alaska	**$ 533**	520	578
Lower 48 and Latin America	**3,247**	2,796	2,228
Canada	**1,531**	1,600	1,758
Europe	**1,334**	1,203	1,405
Asia Pacific and Middle East	**1,188**	1,002	1,063
Other International	**30**	45	8
Corporate and Other	**100**	94	108
Consolidated depreciation, depletion, amortization and impairments	**$ 7,963**	7,260	7,148

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	Millions of Dollars		
	2013	2012	2011
Equity in Earnings of Affiliates			
Alaska	$ **7**	10	(77)
Lower 48 and Latin America	**45**	86	99
Canada	**984**	726	677
Europe	**(3)**	29	46
Asia Pacific and Middle East	**1,162**	1,057	819
Other International	**26**	6	(324)
Corporate and Other	**(2)**	(3)	(1)
Consolidated equity in earnings of affiliates	$ **2,219**	1,911	1,239
Income Taxes			
Alaska	$ **1,275**	1,266	1,171
Lower 48 and Latin America	**534**	133	741
Canada	**(44)**	(252)	(45)
Europe	**2,323**	4,012	4,459
Asia Pacific and Middle East	**1,512**	1,578	1,887
Other International	**933**	1,485	162
LUKOIL Investment	**-**	-	123
Corporate and Other	**(124)**	(280)	(290)
Consolidated income taxes	$ **6,409**	7,942	8,208
Net Income Attributable to ConocoPhillips			
Alaska	$ **2,274**	2,276	1,984
Lower 48 and Latin America	**1,081**	1,029	1,288
Canada	**718**	(684)	91
Europe	**1,199**	1,498	1,830
Asia Pacific and Middle East	**3,532**	3,928	3,032
Other International	**(6)**	359	(377)
LUKOIL Investment	**-**	-	239
Corporate and Other	**(820)**	(993)	(960)
Discontinued operations	**1,178**	1,015	5,309
Consolidated net income attributable to ConocoPhillips	$ **9,156**	8,428	12,436
Investments In and Advances To Affiliates			
Alaska	$ **53**	56	58
Lower 48 and Latin America	**905**	1,133	1,168
Canada	**10,273**	9,973	9,045
Europe	**216**	242	195
Asia Pacific and Middle East	**12,806**	12,468	11,571
Other International	**68**	61	339
Corporate and Other	**16**	15	9
Discontinued operations	**-**	-	10,275
Consolidated investments in and advances to affiliates	$ **24,337**	23,948	32,660

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	Millions of Dollars		
	2013	2012	2011
Total Assets			
Alaska	$ **11,662**	10,950	10,723
Lower 48 and Latin America	**29,571**	28,895	25,872
Canada	**22,394**	22,308	20,847
Europe	**17,299**	15,562	12,452
Asia Pacific and Middle East	**25,473**	23,721	22,374
Other International	**1,610**	1,418	1,542
Corporate and Other	**8,367**	6,823	8,485
Discontinued operations	**1,681**	7,467	50,935
Consolidated total assets	$ **118,057**	117,144	153,230
Capital Expenditures and Investments			
Alaska	$ **1,140**	828	774
Lower 48 and Latin America	**5,234**	5,251	3,882
Canada	**2,232**	2,184	1,761
Europe	**3,115**	2,860	2,222
Asia Pacific and Middle East	**3,382**	2,430	2,325
Other International	**252**	415	8
Corporate and Other	**182**	204	242
Consolidated capital expenditures and investments	$ **15,537**	14,172	11,214
Interest Income and Expense			
Interest income			
Corporate	$ **60**	96	94
Lower 48 and Latin America	**43**	47	51
Europe	**1**	-	-
Asia Pacific and Middle East	**8**	11	7
Other International	**1**	9	18
Interest and debt expense			
Corporate	$ **532**	606	832
Canada	**80**	103	122
Sales and Other Operating Revenues by Product			
Crude oil	$ **24,899**	26,302	24,237
Natural gas	**22,539**	25,163	29,915
Natural gas liquids	**2,111**	2,416	3,101
Other*	**4,864**	4,086	6,943
Consolidated sales and other operating revenues by product	$ **54,413**	57,967	64,196

** Includes LNG and bitumen.*

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Geographic Information

	Millions of Dollars					
	Sales and Other Operating Revenues[1]			Long-Lived Assets[2]		
	2013	2012	2011	**2013**	2012	2011
United States	**$ 27,954**	28,901	32,790	**37,593**	35,443	33,750
Australia[3]	**3,571**	3,371	3,458	**13,450**	13,483	12,572
Canada	**4,647**	4,553	5,326	**21,380**	21,304	20,083
China	**2,120**	1,499	2,154	**2,143**	2,408	2,449
Indonesia	**2,083**	2,198	2,076	**1,780**	1,662	1,726
Malaysia	**281**	-	-	**3,406**	1,832	1,349
Norway	**4,323**	5,059	5,755	**8,089**	7,288	5,918
United Kingdom	**7,717**	9,578	11,314	**5,959**	4,480	3,257
Other foreign countries	**1,717**	2,808	1,323	**3,364**	3,311	3,758
Discontinued operations[4]	**-**	-	-	**-**	-	31,978
Worldwide consolidated	**$ 54,413**	57,967	64,196	**97,164**	91,211	116,840

(1)Sales and other operating revenues are attributable to countries based on the location of the operations generating the revenues.
(2)Defined as net PP&E plus investments in and advances to affiliated companies.
(3)Includes amounts related to the joint petroleum development area with shared ownership held by Australia and Timor-Leste.
(4)Represents the Downstream business.

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 in our operating segments. As a result, amounts reported as equity affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report.

Our proved reserves include estimated quantities related to production sharing contracts (PSCs), which are reported under the “economic interest” method and are subject to fluctuations in 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, 2013, approximately 7 percent of our total proved reserves were under PSCs, located 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), Asia Pacific/Middle East, Africa and Other Areas. Other Areas primarily consists of the Russia and Caspian regions.

As part of our ongoing asset disposition program, we agreed to sell our interest in Kashagan, and the Algeria and Nigeria businesses. These businesses have been considered held for sale since the fourth quarter of 2012 and have been reported as discontinued operations for all periods presented. 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.

During the fourth quarter of 2013, we completed the transactions for the sale of our interest in Kashagan and the Algeria business; accordingly, as of December 31, 2013, we no longer held reserves for these assets. See Note 3—Discontinued Operations, for additional information.

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 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 2013, our processes and controls used to assess over 90 percent of proved reserves as of December 31, 2013, 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 the general processes and controls employed by ConocoPhillips in estimating its December 31, 2013, 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.

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	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed and Undeveloped									
Consolidated operations									
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
Revisions	(7)	20	13	1	(5)	11	23	-	43
Improved recovery	20	-	20	1	-	-	-	-	21
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	9	235	244	1	19	9	22	-	295
Production	(64)	(56)	(120)	(5)	(42)	(29)	(16)	-	(212)
Sales	-	(40)	(40)	-	(3)	-	(21)	(108)	(172)
End of 2013	1,106	606	1,712	22	456	232	237	-	2,659
Equity affiliates									
End of 2010	-	-	-	-	-	102	-	75	177
Revisions	-	-	-	-	-	-	-	(37)	(37)
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	(11)	(16)
Sales	-	-	-	-	-	-	-	-	-
End of 2011	-	-	-	-	-	97	-	27	124
Revisions	-	-	-	-	-	-	-	1	1
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(6)	-	(5)	(11)
Sales	-	-	-	-	-	-	-	(19)	(19)
End of 2012	-	-	-	-	-	91	-	4	95
Revisions	-	-	-	-	-	-	-	1	1
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	(1)	(6)
Sales	-	-	-	-	-	-	-	-	-
End of 2013	-	-	-	-	-	86	-	4	90
Total company									
End of 2010	1,153	261	1,414	22	437	365	252	183	2,673
End of 2011	1,184	296	1,480	24	520	339	243	135	2,741
End of 2012	1,148	447	1,595	24	487	332	229	112	2,779
End of 2013	1,106	606	1,712	22	456	318	237	4	2,749

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Years Ended December 31	Crude Oil Millions of Barrels								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed									
Consolidated operations									
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
End of 2013	1,003	268	1,271	22	247	126	230	-	1,896
Equity affiliates									
End of 2010	-	-	-	-	-	102	-	73	175
End of 2011	-	-	-	-	-	97	-	27	124
End of 2012	-	-	-	-	-	91	-	4	95
End of 2013	-	-	-	-	-	86	-	4	90
Undeveloped									
Consolidated operations									
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
End of 2013	103	338	441	-	209	106	7	-	763
Equity affiliates									
End of 2010	-	-	-	-	-	-	-	2	2
End of 2011	-	-	-	-	-	-	-	-	-
End of 2012	-	-	-	-	-	-	-	-	-
End of 2013	-	-	-	-	-	-	-	-	-

Notable changes in proved crude oil reserves in the three years ended December 31, 2013, included:

- *Extensions and discoveries*: In 2013 and 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 2013, sales in Lower 48 primarily reflect the majority of our producing zones in the Cedar Creek Anticline, sales in Africa reflect the sale of the Algeria business and sales in Other Areas reflect our interest in Kashagan.

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Years Ended December 31	Natural Gas Liquids Millions of Barrels								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed and Undeveloped									
Consolidated operations									
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
Revisions	9	36	45	10	-	(5)	-	-	50
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	58	58	2	-	2	-	-	62
Production	(6)	(34)	(40)	(8)	(2)	(5)	(1)	-	(56)
Sales	-	(1)	(1)	-	-	-	(2)	-	(3)
End of 2013	125	462	587	56	28	14	14	-	699
Equity affiliates									
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
Revisions	-	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(3)	-	-	(3)
Sales	-	-	-	-	-	-	-	-	-
End of 2013	-	-	-	-	-	45	-	-	45
Total company									
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
End of 2013	125	462	587	56	28	59	14	-	744

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Years Ended December 31	Natural Gas Liquids Millions of Barrels								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed									
Consolidated operations									
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
End of 2013	125	362	487	50	19	13	14	-	583
Equity affiliates									
End of 2010	-	-	-	-	-	54	-	-	54
End of 2011	-	-	-	-	-	51	-	-	51
End of 2012	-	-	-	-	-	48	-	-	48
End of 2013	-	-	-	-	-	45	-	-	45
Undeveloped									
Consolidated operations									
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
End of 2013	-	100	100	6	9	1	-	-	116
Equity affiliates									
End of 2010	-	-	-	-	-	-	-	-	-
End of 2011	-	-	-	-	-	-	-	-	-
End of 2012	-	-	-	-	-	-	-	-	-
End of 2013	-	-	-	-	-	-	-	-	-

Notable changes in proved natural gas liquids reserves in the three years ended December 31, 2013, included:

- *Revisions*: In 2013, revisions in Lower 48 were due to higher prices in 2013 versus 2012, as well as improved well performance.

- *Extensions and discoveries*: In 2013 and 2012, extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford, Barnett and Bakken.

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Years Ended December 31	Natural Gas								
	Billions of Cubic Feet								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed and Undeveloped									
Consolidated operations									
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
Revisions	73	214	287	344	16	(53)	94	-	688
Improved recovery	6	-	6	-	-	-	-	-	6
Purchases	-	-	-	1	-	-	-	-	1
Extensions and discoveries	2	508	510	55	159	35	6	-	765
Production	(86)	(592)	(678)	(283)	(171)	(284)	(63)	-	(1,479)
Sales	-	(16)	(16)	(3)	(1)	-	-	(58)	(78)
End of 2013	2,865	6,711	9,576	1,878	1,809	2,046	950	-	16,259
Equity affiliates									
End of 2010	-	-	-	-	-	3,464	-	17	3,481
Revisions	-	-	-	-	-	(76)	-	(11)	(87)
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	259	-	-	259
Production	-	-	-	-	-	(184)	-	(2)	(186)
Sales	-	-	-	-	-	(151)	-	-	(151)
End of 2011	-	-	-	-	-	3,312	-	4	3,316
Revisions	-	-	-	-	-	(75)	-	-	(75)
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	330	-	-	330
Production	-	-	-	-	-	(182)	-	(1)	(183)
Sales	-	-	-	-	-	(127)	-	(3)	(130)
End of 2012	-	-	-	-	-	3,258	-	-	3,258
Revisions	-	-	-	-	-	65	-	-	65
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	982	-	-	982
Production	-	-	-	-	-	(176)	-	-	(176)
Sales	-	-	-	-	-	-	-	-	-
End of 2013	-	-	-	-	-	4,129	-	-	4,129
Total company									
End of 2010	2,862	7,617	10,479	2,305	1,861	6,072	926	73	21,716
End of 2011	2,960	7,188	10,148	2,113	1,896	5,827	872	60	20,916
End of 2012	2,870	6,597	9,467	1,764	1,806	5,606	913	58	19,614
End of 2013	2,865	6,711	9,576	1,878	1,809	6,175	950	-	20,388

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Years Ended December 31	Natural Gas Billions of Cubic Feet								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed									
Consolidated operations									
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
End of 2013	2,815	5,822	8,637	1,786	1,276	1,593	881	-	14,173
Equity affiliates									
End of 2010	-	-	-	-	-	3,114	-	17	3,131
End of 2011	-	-	-	-	-	2,943	-	4	2,947
End of 2012	-	-	-	-	-	2,723	-	-	2,723
End of 2013	-	-	-	-	-	2,606	-	-	2,606
Undeveloped									
Consolidated operations									
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
End of 2013	50	889	939	92	533	453	69	-	2,086
Equity affiliates									
End of 2010	-	-	-	-	-	350	-	-	350
End of 2011	-	-	-	-	-	369	-	-	369
End of 2012	-	-	-	-	-	535	-	-	535
End of 2013	-	-	-	-	-	1,523	-	-	1,523

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 in production operations.

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, 2013, included:

- *Revisions*: In 2013, revisions were primarily due to higher prices in 2013 versus 2012, and improved well performance in Lower 48 and Canada. 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, partially offset by 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.

- *Extensions and discoveries*: In 2013, 2012 and 2011, extensions and discoveries in Lower 48 were primarily due to continued drilling success in Eagle Ford, Bakken and Barnett. In 2013, 2012 and 2011, for our equity affiliates in Asia Pacific/Middle East, extensions and discoveries were due to APLNG's ongoing development drilling onshore Australia.

- *Sales*: In 2012, for our equity affiliates in Asia Pacific/Middle East, sales were primarily due to the dilution of our interest in APLNG.

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Years Ended December 31	Bitumen
	Millions of Barrels
	Canada
Developed and Undeveloped	
Consolidated operations	
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
Revisions	56
Improved recovery	-
Purchases	-
Extensions and discoveries	22
Production	(5)
Sales	-
End of 2013	579
Equity affiliates	
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
Revisions	46
Improved recovery	-
Purchases	-
Extensions and discoveries	46
Production	(35)
Sales	-
End of 2013	1,451
Total company	
End of 2010	1,299
End of 2011	1,439
End of 2012	1,900
End of 2013	2,030

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Years Ended December 31	Bitumen Millions of Barrels
	Canada
Developed	
Consolidated operations	
End of 2010	34
End of 2011	29
End of 2012	25
End of 2013	16
Equity affiliates	
End of 2010	142
End of 2011	131
End of 2012	170
End of 2013	181
Undeveloped	
Consolidated operations	
End of 2010	421
End of 2011	501
End of 2012	481
End of 2013	563
Equity affiliates	
End of 2010	702
End of 2011	778
End of 2012	1,224
End of 2013	1,270

Notable changes in proved bitumen reserves in the three years ended December 31, 2013, included:

- *Revisions*: In 2013, for our consolidated operations, revisions were primarily related to ongoing project development at Surmont and improved well performance. In 2012, for our equity affiliates, revisions were primarily due to well performance and denser well spacing at Foster Creek and Christina Lake. In 2011, for our equity affiliates, 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 equity affiliates, extensions and discoveries were primarily related to the ongoing project development of Christina Lake and sanctioning of Narrows Lake. In 2011, for our consolidated operations, extensions and discoveries were related to continued development of Surmont. In 2011, for our equity affiliates, extensions and discoveries mainly reflect the continued development of FCCL.

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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	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed and Undeveloped									
Consolidated operations									
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
Revisions	14	92	106	124	(3)	(2)	38	-	263
Improved recovery	21	-	21	1	-	-	-	-	22
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	9	378	387	35	46	16	23	-	507
Production	(84)	(189)	(273)	(65)	(73)	(81)	(27)	-	(519)
Sales	-	(44)	(44)	(1)	(3)	-	(23)	(117)	(188)
End of 2013	1,708	2,187	3,895	970	785	588	409	-	6,647
Equity affiliates									
End of 2010	-	-	-	844	-	733	-	78	1,655
Revisions	-	-	-	(101)	-	(12)	-	(39)	(152)
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	187	-	43	-	-	230
Production	-	-	-	(21)	-	(39)	-	(11)	(71)
Sales	-	-	-	-	-	(25)	-	-	(25)
End of 2011	-	-	-	909	-	700	-	28	1,637
Revisions	-	-	-	207	-	(13)	-	1	195
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	307	-	55	-	-	362
Production	-	-	-	(29)	-	(39)	-	(5)	(73)
Sales	-	-	-	-	-	(21)	-	(20)	(41)
End of 2012	-	-	-	1,394	-	682	-	4	2,080
Revisions	-	-	-	46	-	11	-	1	58
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	46	-	164	-	-	210
Production	-	-	-	(35)	-	(38)	-	(1)	(74)
Sales	-	-	-	-	-	-	-	-	-
End of 2013	-	-	-	1,451	-	819	-	4	2,274
Total company									
End of 2010	1,762	1,918	3,680	1,764	779	1,468	424	195	8,310
End of 2011	1,804	1,896	3,700	1,873	870	1,393	406	145	8,387
End of 2012	1,748	1,950	3,698	2,270	818	1,337	398	121	8,642
End of 2013	1,708	2,187	3,895	2,421	785	1,407	409	4	8,921

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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	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed									
Consolidated operations									
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
End of 2013	1,597	1,600	3,197	386	478	405	391	-	4,857
Equity affiliates									
End of 2010	-	-	-	142	-	675	-	76	893
End of 2011	-	-	-	131	-	638	-	28	797
End of 2012	-	-	-	170	-	593	-	4	767
End of 2013	-	-	-	181	-	565	-	4	750
Undeveloped									
Consolidated operations									
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
End of 2013	111	587	698	584	307	183	18	-	1,790
Equity affiliates									
End of 2010	-	-	-	702	-	58	-	2	762
End of 2011	-	-	-	778	-	62	-	-	840
End of 2012	-	-	-	1,224	-	89	-	-	1,313
End of 2013	-	-	-	1,270	-	254	-	-	1,524

Natural gas reserves are converted to barrels of oil equivalent (BOE) based on a 6:1 ratio: six thousand cubic feet of natural gas converts to one BOE.

Proved Undeveloped Reserves

We had 3,314 million BOE of proved undeveloped reserves at year-end 2013, compared with 3,017 million BOE at year-end 2012. During 2013, we converted 330 million BOE of undeveloped reserves to developed primarily through ongoing development activities, as well as from the startup of major development projects. In addition, we added 627 million BOE of undeveloped reserves in 2013, mainly through extensions and discoveries from ongoing development progress, major project sanctions and exploration success, as well as through revisions. These additions were offset by the sale of our interest in Kashagan in 2013, which represented a decrease of 117 million BOE of undeveloped reserves. As a result, at December 31, 2013, our proved undeveloped reserves represented 37 percent of total proved reserves, compared with 35 percent at December 31, 2012. Costs incurred for the year ended December 31, 2013, relating to the development of proved undeveloped reserves were $12.5 billion. A portion of our costs incurred each year relate to development projects where the proved undeveloped reserves will be converted to proved developed reserves in future years.

Approximately 75 percent of our proved undeveloped reserves at year-end 2013 were associated with seven major development areas. Six 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 Eagle Ford area in the Lower 48.
- The APLNG project onshore Australia.
- The Ekofisk Field in the North Sea.

The remaining major development area, Narrows Lake in our FCCL oil sands in Canada, was sanctioned for development in 2012.

At the end of 2013, approximately 20 percent of our total proved undeveloped reserves, located in the Athabasca oil sands in Canada, have remained undeveloped for five years or more. The oil sands in Canada consist 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. Our SAGD projects are large, multi-year projects with steady, long-term production at consistent levels. The associated undeveloped reserves are expected to be developed over the life of the project as additional well pairs are drilled 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 2013, 2012 and 2011 are shown in the following tables. Non-oil and gas activities, such as pipeline and marine operations, liquefied natural gas operations, and crude oil and gas marketing activities are excluded. 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.
- Other related expenses include foreign currency transaction gains and losses and other miscellaneous expenses.

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Results of Operations

Year Ended December 31, 2013	Millions of Dollars Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Disc Ops	Total
Consolidated operations										
Sales	$7,235	7,954	15,189	1,890	6,319	5,261	1,001	-	855	30,515
Transfers	15	183	198	-	-	981	-	-	-	1,179
Other revenues	(5)	57	52	775	(21)	149	141	29	960	2,085
Total revenues	7,245	8,194	15,439	2,665	6,298	6,391	1,142	29	1,815	33,779
Production costs excluding taxes	1,162	1,813	2,975	946	1,095	762	79	1	239	6,097
Taxes other than income taxes	1,681	580	2,261	54	41	386	4	2	5	2,753
Exploration expenses	62	614	676	172	128	107	77	46	10	1,216
Depreciation, depletion and amortization	428	3,200	3,628	1,312	1,006	1,051	29	1	-	7,027
Impairments	-	2	2	216	301	3	-	-	43	565
Transportation costs	703	390	1,093	103	239	122	9	1	27	1,594
Other related expenses	(121)	72	(49)	41	(83)	209	7	20	76	221
Accretion	54	74	128	59	200	24	-	-	5	416
	3,276	1,449	4,725	(238)	3,371	3,727	937	(42)	1,410	13,890
Provision for income taxes	1,168	491	1,659	(270)	2,262	1,509	924	13	251	6,348
Results of operations	$2,108	958	3,066	32	1,109	2,218	13	(55)	1,159	7,542
Equity affiliates										
Sales	$ -	-	-	1,848	-	903	-	117	-	2,868
Transfers	-	-	-	-	-	1,443	-	-	-	1,443
Other revenues	-	-	-	6	-	22	-	-	-	28
Total revenues	-	-	-	1,854	-	2,368	-	117	-	4,339
Production costs excluding taxes	-	-	-	593	-	130	-	14	-	737
Taxes other than income taxes	-	-	-	12	-	1,169	-	59	-	1,240
Exploration expenses	-	-	-	22	30	8	-	-	-	60
Depreciation, depletion and amortization	-	-	-	231	-	137	-	11	-	379
Impairments	-	-	-	-	-	-	-	-	-	-
Transportation costs	-	-	-	-	-	20	-	7	-	27
Other related expenses	-	-	-	7	-	(3)	-	14	-	18
Accretion	-	-	-	5	-	4	-	1	-	10
	-	-	-	984	(30)	903	-	11	-	1,868
Provision for income taxes	-	-	-	248	-	(17)	-	1	-	232
Results of operations	$ -	-	-	736	(30)	920	-	10	-	1,636

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Year Ended December 31, 2012	Millions of Dollars									
	Alaska*	Lower 48	Total U.S.	Canada	Europe	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	1,068	1,460	2,528	788	978	624	56	-	240	5,214
Taxes other than income taxes	2,477	513	2,990	65	24	321	2	6	21	3,429
Exploration expenses	34	343	377	633	102	70	55	211	20	1,468
Depreciation, depletion and amortization	421	2,561	2,982	1,335	958	883	44	1	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	173	136	309	79	(14)	237	8	24	58	701
Accretion	55	66	121	57	186	21	-	-	8	393
	3,435	1,126	4,561	(1,403)	5,520	4,326	1,829	(215)	(31)	14,587
Provision for income taxes	1,229	209	1,438	(391)	3,980	1,514	1,728	(17)	183	8,435
Results of operations	$ 2,206	917	3,123	(1,012)	1,540	2,812	101	(198)	(214)	6,152
Equity affiliates										
Sales	$ -	-	-	1,566	-	930	-	443	-	2,939
Transfers	-	-	-	-	-	1,387	-	-	-	1,387
Other revenues	-	-	-	16	-	(117)	-	407	-	306
Total revenues	-	-	-	1,582	-	2,200	-	850	-	4,632
Production costs excluding taxes	-	-	-	470	-	135	-	45	-	650
Taxes other than income taxes	-	-	-	9	-	1,153	-	293	-	1,455
Exploration expenses	-	-	-	36	2	1	-	4	-	43
Depreciation, depletion and amortization	-	-	-	325	-	109	-	15	-	449
Impairments	-	-	-	-	-	-	-	-	-	-
Transportation costs	-	-	-	-	-	21	-	74	-	95
Other related expenses	-	-	-	11	-	16	-	1	-	28
Accretion	-	-	-	6	-	4	-	1	-	11
	-	-	-	725	(2)	761	-	417	-	1,901
Provision for income taxes	-	-	-	181	-	(29)	-	(233)	-	(81)
Results of operations	$ -	-	-	544	(2)	790	-	650	-	1,982

** Certain amounts were reclassified between "Production costs excluding taxes" and "Other related expenses." Total Results of operations was unchanged.*

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Year Ended December 31, 2011	Millions of Dollars									
	Alaska*	Lower 48	Total U.S.	Canada	Europe	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	987	1,286	2,273	781	956	557	41	-	225	4,833
Taxes other than income taxes	2,721	520	3,241	65	4	543	2	1	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	940	8	1	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	84	105	189	59	43	259	-	33	54	637
Accretion	59	58	117	50	203	23	-	-	3	396
	3,176	2,146	5,322	(580)	6,022	4,214	115	(59)	829	15,863
Provision for income taxes	1,167	755	1,922	(194)	4,355	1,844	160	(3)	545	8,629
Results of operations	$ 2,009	1,391	3,400	(386)	1,667	2,370	(45)	(56)	284	7,234
Equity affiliates										
Sales	$ -	-	-	1,295	-	956	-	1,107	-	3,358
Transfers	-	-	-	-	-	900	-	-	-	900
Other revenues	-	-	-	6	-	(273)	-	-	-	(267)
Total revenues	-	-	-	1,301	-	1,583	-	1,107	-	3,991
Production costs excluding taxes	-	-	-	367	-	108	-	72	-	547
Taxes other than income taxes	-	-	-	5	-	881	-	750	-	1,636
Exploration expenses	-	-	-	36	-	2	-	1	-	39
Depreciation, depletion and amortization	-	-	-	209	-	112	-	52	-	373
Impairments	-	-	-	-	-	-	-	395	-	395
Transportation costs	-	-	-	-	-	15	-	139	-	154
Other related expenses	-	-	-	3	-	(4)	-	-	-	(1)
Accretion	-	-	-	4	-	3	-	1	-	8
	-	-	-	677	-	466	-	(303)	-	840
Provision for income taxes	-	-	-	159	-	32	-	18	-	209
Results of operations	$ -	-	-	518	-	434	-	(321)	-	631

** Certain amounts were reclassified between "Production costs excluding taxes" and "Other related expenses." Total Results of operations was unchanged.*

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Statistics

Net Production	**2013**	2012	2011
	Thousands of Barrels Daily		
Crude Oil			
Consolidated operations			
Alaska	**178**	188	200
Lower 48	**152**	123	94
United States	**330**	311	294
Canada	**13**	13	12
Europe	**113**	135	164
Asia Pacific/Middle East	**80**	68	99
Africa	**26**	40	8
Total consolidated operations	**562**	567	577
Equity affiliates			
Asia Pacific/Middle East	**15**	15	16
Other areas	**4**	13	29
Total equity affiliates	**19**	28	45
Total continuing operations	**581**	595	622
Discontinued operations	**18**	23	28
Total company	**599**	618	650
Natural Gas Liquids			
Consolidated operations			
Alaska	**15**	16	15
Lower 48	**91**	85	74
United States	**106**	101	89
Canada	**25**	24	26
Europe	**6**	7	11
Asia Pacific/Middle East	**12**	16	12
Total consolidated operations	**149**	148	138
Equity affiliates—Asia Pacific/Middle East	**7**	8	7
Total continuing operations	**156**	156	145
Discontinued operations	**3**	4	4
Total company	**159**	160	149
Bitumen			
Consolidated operations—Canada	**13**	12	10
Equity affiliates—Canada	**96**	81	57
Total company	**109**	93	67
Natural Gas	Millions of Cubic Feet Daily		
Consolidated operations			
Alaska	**43**	55	61
Lower 48	**1,490**	1,493	1,556
United States	**1,533**	1,548	1,617
Canada	**775**	857	928
Europe	**416**	516	626
Asia Pacific/Middle East	**709**	672	695
Africa	**25**	18	1
Total consolidated operations	**3,458**	3,611	3,867
Equity affiliates—Asia Pacific/Middle East	**481**	485	492
Total continuing operations	**3,939**	4,096	4,359
Discontinued operations	**129**	149	157
Total company	**4,068**	4,245	4,516

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Average Sales Prices		2013	2012	2011
Crude Oil Per Barrel				
Consolidated operations				
Alaska	$	**107.83**	109.62	105.95
Lower 48		**93.79**	91.67	92.79
United States		**101.45**	102.90	101.89
Canada		**79.73**	78.26	86.04
Europe		**110.56**	113.08	111.82
Asia Pacific/Middle East		**104.78**	108.20	109.84
Africa		**107.21**	110.75	98.30
Total international		**106.43**	109.64	109.76
Total consolidated operations		**103.50**	105.86	105.68
Equity affiliates				
Asia Pacific/Middle East		**105.44**	108.07	106.96
Other areas		**72.43**	96.50	101.62
Total equity affiliates		**97.92**	102.80	103.42
Total continuing operations		**103.32**	105.72	105.52
Discontinued operations		**109.72**	112.90	113.43
Natural Gas Liquids Per Barrel				
Consolidated operations				
Lower 48	$	**31.48**	35.45	50.55
United States		**31.48**	35.45	50.55
Canada		**47.19**	48.64	56.84
Europe		**58.36**	61.53	59.19
Asia Pacific/Middle East		**73.82**	79.26	72.87
Total international		**56.52**	61.01	61.27
Total consolidated operations		**39.60**	44.62	54.79
Equity affiliates—Asia Pacific/Middle East		**73.31**	77.30	70.62
Total continuing operations		**41.42**	46.36	55.73
Discontinued operations		**14.58**	13.30	13.63
Bitumen Per Barrel				
Consolidated operations—Canada	$	**55.25**	57.58	55.16
Equity affiliates—Canada		**53.00**	53.39	63.93
Natural Gas Per Thousand Cubic Feet				
Consolidated operations				
Alaska	$	**4.35**	4.22	4.56
Lower 48		**3.50**	2.67	3.99
United States		**3.52**	2.72	4.01
Canada		**2.92**	2.13	3.46
Europe		**10.68**	9.76	9.26
Asia Pacific/Middle East		**10.61**	10.63	9.82
Africa		**5.38**	5.55	0.09
Total international		**7.46**	6.84	7.04
Total consolidated operations		**5.71**	5.07	5.78
Equity affiliates—Asia Pacific/Middle East		**8.98**	8.54	5.93
Total continuing operations		**6.11**	5.48	5.80
Discontinued operations		**2.60**	2.57	2.25

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	2013	2012	2011
Average Production Costs Per Barrel of Oil Equivalent*			
Consolidated operations			
Alaska**	$ **15.92**	13.69	12.01
Lower 48	**10.12**	8.73	8.24
United States	**11.80**	10.31	9.54
Canada	**14.40**	11.22	10.56
Europe	**15.87**	11.72	9.38
Asia Pacific/Middle East**	**9.94**	8.65	6.72
Africa	**7.21**	3.56	13.75
Total international	**12.97**	10.13	8.92
Total consolidated continuing operations	**12.35**	10.22	9.22
Equity affiliates			
Canada	**16.92**	15.85	17.64
Asia Pacific/Middle East	**3.49**	3.59	2.82
Other areas	**9.59**	9.48	6.80
Total equity affiliates	**10.00**	9.02	7.85
Discontinued operations	**15.23**	12.90	10.60
Average Production Costs Per Barrel—Bitumen			
Consolidated operations—Canada	$ **41.73**	27.09	27.12
Equity affiliates—Canada	**16.92**	15.85	17.64
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent			
Consolidated operations			
Alaska	$ **23.03**	31.75	33.11
Lower 48	**3.24**	3.07	3.33
United States	**8.96**	12.19	13.61
Canada	**0.82**	0.93	0.88
Europe	**0.59**	0.29	0.04
Asia Pacific/Middle East	**5.04**	4.45	6.56
Africa	**0.37**	0.13	0.67
Total international	**2.19**	1.73	2.35
Total consolidated continuing operations	**5.79**	7.00	7.71
Equity affiliates			
Canada	**0.34**	0.30	0.24
Asia Pacific/Middle East	**31.40**	30.63	22.99
Other areas	**40.41**	61.75	70.85
Total equity affiliates	**16.82**	20.20	23.47
Discontinued operations	**0.32**	1.13	0.99
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent			
Consolidated operations			
Alaska	$ **5.86**	5.40	5.69
Lower 48	**17.86**	15.32	13.55
United States	**14.38**	12.16	10.84
Canada	**19.97**	19.01	20.33
Europe	**14.58**	11.47	13.80
Asia Pacific/Middle East	**13.71**	12.25	11.35
Africa	**2.65**	2.80	2.68
Total international	**15.29**	13.33	14.75
Total consolidated continuing operations	**14.81**	12.74	12.89
Equity affiliates			
Canada	**6.59**	10.96	10.05
Asia Pacific/Middle East	**3.68**	2.90	2.92
Other areas	**7.53**	3.16	4.91
Total equity affiliates	**5.14**	6.23	5.35
Discontinued operations	**-**	9.73	8.48

** 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, 2013, 2012 and 2011. 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.

Net Wells Completed	Productive			Dry		
	2013	2012	2011	**2013**	2012	2011
Exploratory(1)(2)						
Consolidated operations						
Alaska	**2**	*	-	**-**	-	-
Lower 48	**67**	92	98	**4**	2	5
United States	**69**	92	98	**4**	2	5
Canada	**5**	5	8	**-**	-	3
Europe	*****	*	1	*****	*	*
Asia Pacific/Middle East	**3**	*	1	*****	-	1
Africa	**-**	*	*	*****	-	*
Other areas	**-**	*	-	*****	*	-
Total consolidated operations	**77**	97	108	**4**	2	9
Equity affiliates						
Asia Pacific/Middle East(3)	**2**	3	8	**-**	-	-
Other areas	**-**	-	-	**-**	*	-
Total equity affiliates	**2**	3	8	**-**	-	-
Includes extension wells of:	*53*	*82*	*98*	**-**	*-*	*3*
Development						
Consolidated operations						
Alaska(4)	**6**	3	10	**-**	-	-
Lower 48	**441**	377	350	**-**	*	4
United States	**447**	380	360	**-**	-	4
Canada	**61**	119	146	**-**	3	1
Europe	**5**	4	4	*****	-	-
Asia Pacific/Middle East	**29**	11	30	**-**	-	-
Africa	**4**	4	5	**-**	-	-
Other areas	*****	-	-	**-**	-	-
Total consolidated operations	**546**	518	545	**-**	3	5
Equity affiliates						
Canada	**46**	30	20	**-**	-	-
Asia Pacific/Middle East(3)	**24**	9	7	*****	-	1
Other areas	**-**	1	3	**-**	-	-
Total equity affiliates	**70**	40	30	**-**	-	1

(1)Excludes net stratigraphic-type exploratory wells of 149, 135 and 207 for the years ended December 31, 2013, 2012 and 2011, respectively.
(2)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.
(3)Productive wells from prior periods were reclassified between "Exploratory" and "Development."
(4)Prior periods have been restated to exclude sidetracks. Sidetracks and laterals, which are both excluded, are a significant part of the Alaska drilling program.
** 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, 2013, and includes wells in the process of drilling or in active completion. It also represents gross and net productive wells, including producing wells and wells capable of production at December 31, 2013.

Wells at December 31, 2013			Productive*			
	In Progress		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
Consolidated operations						
Alaska	5	3	1,735	765	32	20
Lower 48	338	185	9,557	4,950	24,501	16,238
United States	343	188	11,292	5,715	24,533	16,258
Canada	102	60	1,685	964	12,493	7,323
Europe	12	2	463	82	271	111
Asia Pacific/Middle East	45	16	404	172	120	54
Africa	32	5	1,102	190	63	12
Total consolidated operations	534	271	14,946	7,123	37,480	23,758
Equity affiliates						
Canada	19	10	334	167	-	-
Asia Pacific/Middle East	1,430	298	-	-	744	165
Other areas	-	-	30	15	-	-
Total equity affiliates	1,449	308	364	182	744	165

** Includes 365 gross and 174 net multiple completion wells.*

Acreage at December 31, 2013	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Consolidated operations				
Alaska	674	325	1,349	915
Lower 48	5,784	4,436	12,893	10,823
United States	6,458	4,761	14,242	11,738
Canada	6,666	4,323	5,464	3,627
Europe	845	255	2,355	739
Asia Pacific/Middle East	4,031	1,736	28,018	16,107
Africa	439	75	19,002	4,323
Other areas	-	-	4,604	2,354
Total consolidated operations	18,439	11,150	73,685	38,888
Equity affiliates				
Canada	49	19	661	280
Europe	-	-	506	354
Asia Pacific/Middle East	367	76	8,462	2,502
Other areas	16	8	619	309
Total equity affiliates	432	103	10,248	3,445

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Costs Incurred

Year Ended December 31	Millions of Dollars								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
2013									
Consolidated operations									
Unproved property acquisition	$ 3	311	314	90	-	111	177	15	707
Proved property acquisition	-	4	4	10	-	-	-	-	14
	3	315	318	100	-	111	177	15	721
Exploration	159	1,156	1,315	294	240	321	136	49	2,355
Development	925	4,067	4,992	1,952	3,999	2,256	216	409	13,824
	$1,087	5,538	6,625	2,346	4,239	2,688	529	473	16,900
Equity affiliates									
Unproved property acquisition	$ -	-	-	1	-	51	-	-	52
Proved property acquisition	-	-	-	-	-	-	-	-	-
	-	-	-	1	-	51	-	-	52
Exploration	-	-	-	59	31	101	-	-	191
Development	-	-	-	1,532	-	2,141	-	3	3,676
	$ -	-	-	1,592	31	2,293	-	3	3,919
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	248	94	142	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	1,361	635	727	15,162
Equity affiliates									
Unproved property acquisition	$ -	-	-	12	-	-	-	-	12
Proved property acquisition	-	-	-	-	-	-	-	-	-
	-	-	-	12	-	-	-	-	12
Exploration	-	-	-	77	11	52	-	-	140
Development	-	-	-	1,332	-	1,163	-	13	2,508
	$ -	-	-	1,421	11	1,215	-	13	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	226	63	89	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	1,211	326	815	11,272
Equity affiliates									
Unproved property acquisition	$ -	-	-	-	-	484	-	-	484
Proved property acquisition	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	484	-	-	484
Exploration	-	-	-	64	-	100	-	1	165
Development	-	-	-	911	-	478	-	43	1,432
	$ -	-	-	975	-	1,062	-	44	2,081

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Capitalized Costs

At December 31	Millions of Dollars								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
2013									
Consolidated operations									
Proved property	$14,382	42,118	56,500	22,612	28,523	14,513	2,628	9	124,785
Unproved property	1,644	2,931	4,575	1,966	308	931	742	16	8,538
	16,026	45,049	61,075	24,578	28,831	15,444	3,370	25	133,323
Accumulated depreciation, depletion and amortization	7,107	19,840	26,947	13,473	15,131	6,504	1,043	9	63,107
	$ 8,919	25,209	34,128	11,105	13,700	8,940	2,327	16	70,216
Equity affiliates									
Proved property	$ -	-	-	8,525	-	6,994	-	211	15,730
Unproved property	-	-	-	1,379	57	4,097	-	-	5,533
	-	-	-	9,904	57	11,091	-	211	21,263
Accumulated depreciation, depletion and amortization	-	-	-	1,199	-	446	-	191	1,836
	$ -	-	-	8,705	57	10,645	-	20	19,427
2012									
Consolidated operations									
Proved property	$13,470	40,019	53,489	22,069	25,426	12,248	4,060	5,241	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	13,270	4,571	5,461	131,024
Accumulated depreciation, depletion and amortization	6,676	18,186	24,862	12,807	14,317	5,460	1,787	676	59,909
	$ 8,337	24,673	33,010	11,333	11,393	7,810	2,784	4,785	71,115
Equity affiliates									
Proved property	$ -	-	-	7,498	-	4,067	-	212	11,777
Unproved property	-	-	-	1,450	53	6,212	-	-	7,715
	-	-	-	8,948	53	10,279	-	212	19,492
Accumulated depreciation, depletion and amortization	-	-	-	1,046	-	277	-	183	1,506
	$ -	-	-	7,902	53	10,002	-	29	17,986

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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	Asia Pacific/ Middle East	Africa	Other Areas	Total
2013									
Consolidated operations									
Future cash inflows	$133,372	93,276	226,648	39,695	69,654	43,827	33,055	-	412,879
Less:									
Future production and transportation costs	74,624	34,344	108,968	22,435	16,902	14,567	4,148	-	167,020
Future development costs	12,282	15,833	28,115	12,228	14,821	3,250	695	-	59,109
Future income tax provisions	16,356	14,810	31,166	401	24,706	8,388	25,371	-	90,032
Future net cash flows	30,110	28,289	58,399	4,631	13,225	17,622	2,841	-	96,718
10 percent annual discount	16,187	11,217	27,404	2,881	4,298	5,046	1,086	-	40,715
Discounted future net cash flows	$ 13,923	17,072	30,995	1,750	8,927	12,576	1,755	-	56,003
Equity affiliates									
Future cash inflows	$ -	-	-	72,327	-	55,327	-	296	127,950
Less:									
Future production and transportation costs	-	-	-	24,953	-	26,356	-	233	51,542
Future development costs	-	-	-	10,673	-	2,616	-	13	13,302
Future income tax provisions	-	-	-	8,776	-	5,471	-	6	14,253
Future net cash flows	-	-	-	27,925	-	20,884	-	44	48,853
10 percent annual discount	-	-	-	17,643	-	9,697	-	4	27,344
Discounted future net cash flows	$ -	-	-	10,282	-	11,187	-	40	21,509
Total company									
Discounted future net cash flows	$ 13,923	17,072	30,995	12,032	8,927	23,763	1,755	40	77,512

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	Millions of Dollars								
	Alaska	Lower 48	Total U.S.	Canada*	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
2012									
Consolidated operations									
Future cash inflows	$141,668	71,556	213,224	37,814	73,379	49,234	32,009	12,012	417,672
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	-	28,187	10,424	22,595	1,331	89,747
Future net cash flows	29,952	21,665	51,617	4,255	13,739	19,757	4,128	5,870	99,366
10 percent annual discount	16,511	9,461	25,972	2,963	4,936	6,393	1,442	3,711	45,417
Discounted future net cash flows	$ 13,441	12,204	25,645	1,292	8,803	13,364	2,686	2,159	53,949
Equity affiliates									
Future cash inflows	$ -	-	-	72,587	-	47,394	-	323	120,304
Less:									
Future production and transportation costs	-	-	-	23,967	-	23,689	-	245	47,901
Future development costs	-	-	-	11,109	-	1,221	-	10	12,340
Future income tax provisions	-	-	-	9,126	-	4,335	-	3	13,464
Future net cash flows	-	-	-	28,385	-	18,149	-	65	46,599
10 percent annual discount	-	-	-	18,669	-	8,677	-	9	27,355
Discounted future net cash flows	$ -	-	-	9,716	-	9,472	-	56	19,244
Total company									
Discounted future net cash flows	$ 13,441	12,204	25,645	11,008	8,803	22,836	2,686	2,215	73,193

* *Canada consolidated operations were restated for a price revision impacting future cash inflows and certain assumptions regarding future income tax provisions. Canada equity affiliates future development costs were restated to include certain expected capital expenditures related to facilities and certain assumptions regarding future income tax provisions.*

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	Millions of Dollars								
	Alaska	Lower 48	Total U.S.	Canada*	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
2011									
Consolidated operations									
Future cash inflows	$143,652	73,807	217,459	41,564	78,250	49,936	33,017	11,891	432,117
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	1,255	29,853	11,967	23,825	990	96,506
Future net cash flows	32,649	21,751	54,400	7,768	14,245	20,538	4,194	5,053	106,198
10 percent annual discount	18,074	9,643	27,717	5,413	5,372	6,649	1,522	3,712	50,385
Discounted future net cash flows	$ 14,575	12,108	26,683	2,355	8,873	13,889	2,672	1,341	55,813
Equity affiliates									
Future cash inflows	$ -	-	-	55,652	-	35,439	-	2,786	93,877
Less:									
Future production and transportation costs	-	-	-	16,405	-	16,814	-	2,765	35,984
Future development costs	-	-	-	7,163	-	905	-	36	8,104
Future income tax provisions	-	-	-	7,819	-	3,705	-	3	11,527
Future net cash flows	-	-	-	24,265	-	14,015	-	(18)	38,262
10 percent annual discount	-	-	-	15,875	-	7,217	-	(39)	23,053
Discounted future net cash flows	$ -	-	-	8,390	-	6,798	-	21	15,209
Total company									
Discounted future net cash flows	$ 14,575	12,108	26,683	10,745	8,873	20,687	2,672	1,362	71,022

* *Canada consolidated operations and equity affiliates were restated for foreign currency exchange impacts on future cash inflows and certain assumptions regarding future income tax provisions.*

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Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars								
	Consolidated Operations			Equity Affiliates			Total Company		
	2013	2012*	2011*	**2013**	2012*	2011*	**2013**	2012	2011
Discounted future net cash flows at the beginning of the year	**$ 53,949**	55,813	45,466	**19,244**	15,209	11,094	**73,193**	71,022	56,560
Changes during the year									
Revenues less production and transportation costs for the year	**(21,250)**	(22,748)	(24,444)	**(2,307)**	(2,126)	(1,921)	**(23,557)**	(24,874)	(26,365)
Net change in prices and production and transportation costs	**(611)**	(5,451)	34,340	**(1,645)**	114	5,213	**(2,256)**	(5,337)	39,553
Extensions, discoveries and improved recovery, less estimated future costs	**15,796**	11,192	8,564	**1,804**	1,963	956	**17,600**	13,155	9,520
Development costs for the year	**11,640**	10,944	8,428	**3,675**	2,438	1,488	**15,315**	13,382	9,916
Changes in estimated future development costs	**(9,760)**	(9,832)	(8,374)	**(3,167)**	(3,285)	(1,508)	**(12,927)**	(13,117)	(9,882)
Purchases of reserves in place, less estimated future costs	**2**	16	19	**-**	-	-	**2**	16	19
Sales of reserves in place, less estimated future costs	**(5,997)**	(913)	(390)	**-**	(139)	(234)	**(5,997)**	(1,052)	(624)
Revisions of previous quantity estimates	**4,317**	2,042	(1,628)	**2,357**	3,952	526	**6,674**	5,994	(1,102)
Accretion of discount	**9,732**	10,095	7,710	**2,331**	1,858	1,284	**12,063**	11,953	8,994
Net change in income taxes	**(1,815)**	2,791	(13,878)	**(783)**	(740)	(1,689)	**(2,598)**	2,051	(15,567)
Total changes	**2,054**	(1,864)	10,347	**2,265**	4,035	4,115	**4,319**	2,171	14,462
Discounted future net cash flows at year end	**$ 56,003**	53,949	55,813	**21,509**	19,244	15,209	**77,512**	73,193	71,022

* *Certain amounts in Canada consolidated operations and equity affiliates were restated for price revisions and foreign currency exchange impacts on future cash inflows, certain assumptions regarding future income tax provisions and to include certain expected capital expenditures related to facilities.*

- 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	
					Net Income Attributable to ConocoPhillips	
	Sales and Other Operating Revenues	Income From Continuing Operations Before Income Taxes	Net Income	Net Income Attributable to ConocoPhillips	Basic	Diluted
2013						
First	**$ 14,166**	**3,787**	**2,153**	**2,139**	**1.74**	**1.73**
Second	**13,350**	**3,696**	**2,063**	**2,050**	**1.66**	**1.65**
Third	**13,643**	**4,405**	**2,496**	**2,480**	**2.01**	**2.00**
Fourth	**13,254**	**2,558**	**2,503**	**2,487**	**2.01**	**2.00**
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

Supplementary Information—Condensed Consolidating Financial Information

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company, ConocoPhillips Australia Funding Company and ConocoPhillips Canada Funding Company I, with respect to publicly held debt securities. ConocoPhillips Company is 100 percent owned by ConocoPhillips. ConocoPhillips Australia Funding Company and ConocoPhillips Canada Funding Company I 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 and ConocoPhillips Canada Funding Company I, 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 and ConocoPhillips Canada Funding Company I (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.

In 2013, we completed a legal amalgamation of ConocoPhillips Canada Funding Company I, ConocoPhillips Canada Funding Company II and Burlington Resources Finance Company, with the amalgamated company continuing as ConocoPhillips Canada Funding Company I. The amalgamation did not significantly change the nature of the outstanding debt of these entities or the terms of parental guarantees, which remain full and unconditional, as well as joint and several. The amalgamation did not impact our consolidated financial position, results of operations or cash flows.

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, 2013						
Income Statement	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income							
Sales and other operating revenues	$ -	18,186	-	-	36,227	-	54,413
Equity in earnings of affiliates	8,374	9,200	-	-	2,611	(17,966)	2,219
Gain on dispositions	-	364	-	-	878	-	1,242
Other income	2	271	-	-	101	-	374
Intercompany revenues	82	458	13	305	4,948	(5,806)	-
Total Revenues and Other Income	8,458	28,479	13	305	44,765	(23,772)	58,248
Costs and Expenses							
Purchased commodities	-	15,779	-	-	11,812	(4,948)	22,643
Production and operating expenses	-	1,492	-	-	5,756	(10)	7,238
Selling, general and administrative expenses	11	623	-	1	238	(19)	854
Exploration expenses	-	659	-	-	573	-	1,232
Depreciation, depletion and amortization	-	907	-	-	6,527	-	7,434
Impairments	-	4	-	-	525	-	529
Taxes other than income taxes	-	236	-	-	2,648	-	2,884
Accretion on discounted liabilities	-	56	-	-	378	-	434
Interest and debt expense	630	327	12	235	237	(829)	612
Foreign currency transaction (gains) losses	52	3	-	(349)	236	-	(58)
Total Costs and Expenses	693	20,086	12	(113)	28,930	(5,806)	43,802
Income from continuing operations before income taxes	7,765	8,393	1	418	15,835	(17,966)	14,446
Provision for income taxes	(213)	19	-	31	6,572	-	6,409
Income From Continuing Operations	7,978	8,374	1	387	9,263	(17,966)	8,037
Income from discontinued operations	1,178	1,178	-	-	1,178	(2,356)	1,178
Net income	9,156	9,552	1	387	10,441	(20,322)	9,215
Less: net income attributable to noncontrolling interests	-	-	-	-	(59)	-	(59)
Net Income Attributable to ConocoPhillips	$ 9,156	9,552	1	387	10,382	(20,322)	9,156
Comprehensive Income Attributable to ConocoPhillips	$ 7,071	7,467	1	99	7,782	(15,349)	7,071

Income Statement	Year Ended December 31, 2012						
Revenues and Other Income							
Sales and other operating revenues	$ -	17,768	-	-	40,199	-	57,967
Equity in earnings of affiliates*	7,871	8,545	-	-	1,832	(16,337)	1,911
Gain on dispositions	-	2	-	-	1,655	-	1,657
Other income (loss)	(76)	177	-	-	368	-	469
Intercompany revenues*	61	1,077	46	313	2,997	(4,494)	-
Total Revenues and Other Income	7,856	27,569	46	313	47,051	(20,831)	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	-	1	258	(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*	700	316	42	237	427	(1,013)	709
Foreign currency transaction (gains) losses	(19)	19	-	152	(111)	-	41
Total Costs and Expenses	693	19,698	42	390	30,252	(4,494)	46,581
Income (loss) from continuing operations before income taxes	7,163	7,871	4	(77)	16,799	(16,337)	15,423
Provision for income taxes	(248)	(1)	1	9	8,181	-	7,942
Income (Loss) From Continuing Operations	7,411	7,872	3	(86)	8,618	(16,337)	7,481
Income from discontinued operations	1,017	1,017	-	-	777	(1,794)	1,017
Net income (loss)	8,428	8,889	3	(86)	9,395	(18,131)	8,498
Less: net income attributable to noncontrolling interests	-	-	-	-	(70)	-	(70)
Net Income (Loss) Attributable to ConocoPhillips	$ 8,428	8,889	3	(86)	9,325	(18,131)	8,428
Comprehensive Income Attributable to ConocoPhillips	$ 9,055	9,516	3	24	9,560	(19,103)	9,055

* *"Interest and debt expense" for ConocoPhillips was revised to reflect contractually agreed interest rates, with offsetting adjustments in the "Equity in earnings of affiliates" and "Intercompany revenues" lines for ConocoPhillips, ConocoPhillips Company and All Other Subsidiaries. There was no impact to Total Consolidated balances.*

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Income Statement	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars						
	Year Ended December 31, 2011						
Revenues and Other Income							
Sales and other operating revenues	$ -	20,606	-	-	43,590	-	64,196
Equity in earnings of affiliates*	7,600	7,317	-	-	1,312	(14,990)	1,239
Gain on dispositions	-	261	-	-	109	-	370
Other income	-	98	-	-	166	-	264
Intercompany revenues*	4	1,406	46	328	1,766	(3,550)	-
Total Revenues and Other Income	7,604	29,688	46	328	46,943	(18,540)	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	-	1	253	(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*	726	448	42	220	562	(1,044)	954
Foreign currency transaction (gains) losses	-	(16)	-	37	3	-	24
Total Costs and Expenses	739	21,687	42	258	31,497	(3,550)	50,673
Income from continuing operations before income taxes	6,865	8,001	4	70	15,446	(14,990)	15,396
Provision for income taxes	(257)	401	1	-	8,063	-	8,208
Income From Continuing Operations	7,122	7,600	3	70	7,383	(14,990)	7,188
Income from discontinued operations	5,314	5,314	-	-	4,868	(10,182)	5,314
Net income	12,436	12,914	3	70	12,251	(25,172)	12,502
Less: net income attributable to noncontrolling interests	-	-	-	-	(66)	-	(66)
Net Income Attributable to ConocoPhillips	$ 12,436	12,914	3	70	12,185	(25,172)	12,436
Comprehensive Income (Loss) Attributable to ConocoPhillips	$ 10,749	11,227	3	(28)	10,973	(22,175)	10,749

* *"Interest and debt expense" for ConocoPhillips was revised to reflect contractually agreed interest rates, with offsetting adjustments in the "Equity in earnings of affiliates" and "Intercompany revenues" lines for ConocoPhillips, ConocoPhillips Company and All Other Subsidiaries. There was no impact to Total Consolidated balances.*

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Balance Sheet	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars						
	At December 31, 2013						
Assets							
Cash and cash equivalents	$ -	2,434	-	229	3,583	-	6,246
Short-term investments	-	-	-	-	272	-	272
Accounts and notes receivable	73	2,122	2	-	9,267	(2,977)	8,487
Inventories	-	174	-	-	1,020	-	1,194
Prepaid expenses and other current assets	20	535	-	35	2,311	(77)	2,824
Total Current Assets	93	5,265	2	264	16,453	(3,054)	19,023
Investments, loans and long-term receivables(1)	86,836	100,052	-	4,259	34,795	(200,678)	25,264
Net properties, plants and equipment	-	9,313	-	-	63,514	-	72,827
Other assets	38	260	-	103	1,394	(852)	943
Total Assets	$ 86,967	114,890	2	4,626	116,156	(204,584)	118,057
Liabilities and Stockholders' Equity							
Accounts payable	$ -	3,388	-	4	8,899	(2,977)	9,314
Short-term debt	395	4	-	5	185	-	589
Accrued income and other taxes	-	223	-	-	2,517	(27)	2,713
Employee benefit obligations	-	566	-	-	276	-	842
Other accruals	210	639	-	81	790	(49)	1,671
Total Current Liabilities	605	4,820	-	90	12,667	(3,053)	15,129
Long-term debt	9,047	5,208	-	2,980	3,838	-	21,073
Asset retirement obligations and accrued environmental costs	-	1,289	-	-	8,594	-	9,883
Deferred income taxes	94	557	-	-	14,569	-	15,220
Employee benefit obligations	-	1,791	-	-	668	-	2,459
Other liabilities and deferred credits(1)	31,693	9,422	-	1,603	22,204	(63,121)	1,801
Total Liabilities	41,439	23,087	-	4,673	62,540	(66,174)	65,565
Retained earnings	34,636	31,835	-	(1,500)	12,848	(36,659)	41,160
Other common stockholders' equity	10,892	59,968	2	1,453	40,366	(101,751)	10,930
Noncontrolling interests	-	-	-	-	402	-	402
Total Liabilities and Stockholders' Equity	$ 86,967	114,890	2	4,626	116,156	(204,584)	118,057

Balance Sheet	At December 31, 2012						
Assets							
Cash and cash equivalents	$ 2	12	6	59	3,539	-	3,618
Restricted cash	748	-	-	-	-	-	748
Accounts and notes receivable	64	2,711	-	-	11,503	(5,096)	9,182
Inventories	-	57	-	-	908	-	965
Prepaid expenses and other current assets	20	848	-	30	8,659	(81)	9,476
Total Current Assets	834	3,628	6	89	24,609	(5,177)	23,989
Investments, loans and long-term receivables(1)(2)	79,428	107,926	760	4,551	49,488	(217,147)	25,006
Net properties, plants and equipment	-	8,771	-	-	58,492	-	67,263
Other assets	55	216	-	163	1,654	(1,202)	886
Total Assets	$ 80,317	120,541	766	4,803	134,243	(223,526)	117,144
Liabilities and Stockholders' Equity							
Accounts payable	$ -	5,532	-	15	9,562	(5,096)	10,013
Short-term debt	(5)	4	751	5	200	-	955
Accrued income and other taxes	-	104	-	-	3,291	(29)	3,366
Employee benefit obligations	-	485	-	-	257	-	742
Other accruals	210	636	9	90	1,474	(52)	2,367
Total Current Liabilities	205	6,761	760	110	14,784	(5,177)	17,443
Long-term debt	9,453	5,215	-	2,985	3,117	-	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	-	23	12,549	-	13,185
Employee benefit obligations	-	2,464	-	-	882	-	3,346
Other liabilities and deferred credits(1)(2)	29,220	19,917	-	1,830	24,953	(73,704)	2,216
Total Liabilities	38,893	36,205	760	4,948	66,792	(78,881)	68,717
Retained earnings(2)	28,814	22,283	3	(1,887)	24,541	(38,416)	35,338
Other common stockholders' equity	12,610	62,053	3	1,742	42,470	(106,229)	12,649
Noncontrolling interests	-	-	-	-	440	-	440
Total Liabilities and Stockholders' Equity	$ 80,317	120,541	766	4,803	134,243	(223,526)	117,144

(1) Includes intercompany loans.

(2) Revised to reflect adjustments to intercompany interest for ConocoPhillips, ConocoPhillips Company, and All Other Subsidiaries, and to reduce "Investments, loans, and long-term receivables" and "Retained earnings" in the All Other Subsidiaries column to conform to current-year presentation. There was no impact to Total Consolidated balances.

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Statement of Cash Flows	Millions of Dollars						
	Year Ended December 31, 2013						
	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities							
Net cash provided by (used in) continuing operating activities	$ (295)	22,996	(2)	1	14,387	(21,286)	15,801
Net cash provided by discontinued operations	-	91	-	-	643	(448)	286
Net Cash Provided by (Used in) Operating Activities	(295)	23,087	(2)	1	15,030	(21,734)	16,087
Cash Flows From Investing Activities							
Capital expenditures and investments	-	(4,821)	-	-	(13,566)	2,850	(15,537)
Proceeds from asset dispositions	-	2,633	-	-	9,745	(2,158)	10,220
Net purchases of short-term investments	-	-	-	-	(263)	-	(263)
Long-term advances/loans—related parties	-	(342)	-	-	(545)	887	-
Collection of advances/loans—related parties	-	174	750	169	3,010	(3,958)	145
Intercompany cash management	2,511	(15,919)	-	-	13,408	-	-
Other	-	21	-	-	(233)	-	(212)
Net cash provided by (used in) continuing investing activities	2,511	(18,254)	750	169	11,556	(2,379)	(5,647)
Net cash used in discontinued operations	-	(52)	-	-	(604)	52	(604)
Net Cash Provided by (Used in) Investing Activities	2,511	(18,306)	750	169	10,952	(2,327)	(6,251)
Cash Flows From Financing Activities							
Issuance of debt	-	522	-	-	365	(887)	-
Repayment of debt	-	(2,924)	(750)	-	(1,230)	3,958	(946)
Change in restricted cash	748	-	-	-	-	-	748
Issuance of company common stock	365	-	-	-	-	(345)	20
Dividends paid	(3,334)	-	(4)	-	(21,984)	21,988	(3,334)
Other	3	52	-	-	(2,984)	(692)	(3,621)
Net cash used in continuing financing activities	(2,218)	(2,350)	(754)	-	(25,833)	24,022	(7,133)
Net cash used in discontinued operations	-	-	-	-	(39)	39	-
Net Cash Used in Financing Activities	(2,218)	(2,350)	(754)	-	(25,872)	24,061	(7,133)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	(9)	-	-	(66)	-	(75)
Net Change in Cash and Cash Equivalents	(2)	2,422	(6)	170	44	-	2,628
Cash and cash equivalents at beginning of period	2	12	6	59	3,539	-	3,618
Cash and Cash Equivalents at End of Period	$ -	2,434	-	229	3,583	-	6,246

Statement of Cash Flows	Year Ended December 31, 2012*						
Cash Flows From Operating Activities							
Net cash provided by (used in) continuing operating activities	$ (456)	6,470	5	(2)	15,748	(8,307)	13,458
Net cash provided by (used in) discontinued operations	-	6,201	-	-	(1,355)	(4,382)	464
Net Cash Provided by (Used in) Operating Activities	(456)	12,671	5	(2)	14,393	(12,689)	13,922
Cash Flows From Investing Activities							
Capital expenditures and investments	-	(1,323)	-	-	(12,433)	(416)	(14,172)
Proceeds from asset dispositions	-	16,505	-	-	2,126	(16,499)	2,132
Net sales of short-term investments	-	-	-	-	597	-	597
Long-term advances/loans—related parties	-	(378)	-	-	(8,272)	8,650	-
Collection of advances/loans—related parties	-	1,193	-	6	5,884	(6,969)	114
Intercompany cash management	3,840	(16,040)	-	-	12,200	-	-
Other	-	442	-	-	379	-	821
Net cash provided by continuing investing activities	3,840	399	-	6	481	(15,234)	(10,508)
Net cash provided by (used in) discontinued operations	(303)	(11,292)	-	-	14,241	(3,765)	(1,119)
Net Cash Provided by (Used in) Investing Activities	3,537	(10,893)	-	6	14,722	(18,999)	(11,627)
Cash Flows From Financing Activities							
Issuance of debt	-	10,285	-	-	361	(8,650)	1,996
Repayment of debt	(2,474)	(5,833)	-	-	(1,227)	6,969	(2,565)
Special cash distribution from Phillips 66	7,818	-	-	-	-	-	7,818
Change in restricted cash	(748)	-	-	-	-	-	(748)
Issuance of company common stock	701	-	-	-	-	(563)	138
Repurchase of company common stock	(5,098)	-	-	-	-	-	(5,098)
Dividends paid	(3,278)	-	-	-	(7,645)	7,645	(3,278)
Other	-	118	-	-	(17,339)	16,496	(725)
Net cash provided by (used in) continuing financing activities	(3,079)	4,570	-	-	(25,850)	21,897	(2,462)
Net cash used in discontinued operations	-	(8,327)	-	-	(3,483)	9,791	(2,019)
Net Cash Used in Financing Activities	(3,079)	(3,757)	-	-	(29,333)	31,688	(4,481)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	(37)	-	-	61	-	24
Net Change in Cash and Cash Equivalents	2	(2,016)	5	4	(157)	-	(2,162)
Cash and cash equivalents at beginning of period	-	2,028	1	55	3,696	-	5,780

Cash and Cash Equivalents at End of Period	$ 2	12	6	59	3,539	-	3,618

* *Revised to reflect intercompany cash management activities previously presented as cash flows from continuing operating activities as both continuing activities and discontinued operations in "Cash Flows From Investing Activities" and "Cash Flows From Financing Activities." There was no impact to Total Consolidated balances.*

Statement of Cash Flows	Millions of Dollars						
	Year Ended December 31, 2011*						
	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities							
Net cash provided by (used in) continuing operating activities	$ (502)	6,415	1	(273)	14,179	(5,867)	13,953
Net cash provided by discontinued operations	-	(2,048)	-	-	4,691	3,050	5,693
Net Cash Provided by (Used in) Operating Activities	(502)	4,367	1	(273)	18,870	(2,817)	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 sales of short-term investments	-	-	-	-	400	-	400
Long-term advances/loans—related parties	-	(831)	-	(4)	(5,334)	6,169	-
Collection of advances/loans—related parties	-	909	-	-	8,338	(9,149)	98
Intercompany cash management	14,643	(11,516)	-	-	(3,127)	-	-
Other	-	6	-	-	44	-	50
Net cash provided by (used in) continuing investing activities	14,643	(12,618)	-	(4)	(7,515)	(2,980)	(8,474)
Net cash provided by (used in) discontinued operations	-	5,360	-	-	(12,101)	8,200	1,459
Net Cash Provided by (Used in) Investing Activities	14,643	(7,258)	-	(4)	(19,616)	5,220	(7,015)
Cash Flows From Financing Activities							
Issuance of debt	-	4,558	-	784	827	(6,169)	-
Repayment of debt	-	(8,657)	-	(500)	(926)	9,149	(934)
Issuance of company common stock	623	-	-	-	-	(527)	96
Repurchase of company common stock	(11,123)	-	-	-	-	-	(11,123)
Dividends paid	(3,632)	-	-	-	(3,031)	3,031	(3,632)
Other	(9)	119	-	-	(794)	-	(684)
Net cash provided by (used in) continuing financing activities	(14,141)	(3,980)	-	284	(3,924)	5,484	(16,277)
Net cash provided by (used in) discontinued operations	-	8,182	-	-	(323)	(7,887)	(28)
Net Cash Provided by (Used in) Financing Activities	(14,141)	4,202	-	284	(4,247)	(2,403)	(16,305)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	(1)	-	2	(1)	-	-
Net Change in Cash and Cash Equivalents	-	1,310	1	9	(4,994)	-	(3,674)
Cash and cash equivalents at beginning of period	-	718	-	46	8,690	-	9,454
Cash and Cash Equivalents at End of Period	$ -	2,028	1	55	3,696	-	5,780

* *Revised to reflect intercompany cash management activities previously presented as cash flows from continuing operating activities as both continuing activities and discontinued operations in "Cash Flows From Investing Activities" and "Cash Flows From Financing Activities." There was no impact to Total Consolidated balances.*

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, 2013, 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, 2013.

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 76 and is incorporated herein by reference.

Report of Independent Registered Public Accounting Firm

This report is included in Item 8 on page 78 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 31 and 32.

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 website at *www.conocophillips.com* (within the Investors>Corporate 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 website.

All other information required by Item 10 of Part III will be included in our Proxy Statement relating to our 2014 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2014, 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 2014 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2014, 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 2014 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2014, 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 2014 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2014, 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 2014 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2014, 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 2014 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 75, are filed as part of this annual report.

2. Financial Statement Schedules

Schedule II—Valuation and Qualifying Accounts, appears below. All other schedules are omitted because they are not required, not significant, not applicable or the information is shown in another schedule, the financial statements or the notes to consolidated financial statements.

3. Exhibits

The exhibits listed in the Index to Exhibits, which appears on pages 175 through 180, 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
2013					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	**$ 10**	**-**	**-**	**(2)(b)**	**8**
Deferred tax asset valuation allowance	**1,345**	**(357)**	**3**	**(22)**	**969**
Included in other liabilities:					
Restructuring accruals	**17**	**10**	**(1)**	**(7)(c)**	**19**
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

(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 December 6, 2013 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed December 10, 2013; 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. 001-00720).
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).
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).

Exhibit Number	Description
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).
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).

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Exhibit Number	Description
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 (Amended and Restated Effective as of January 1, 2014).
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).
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).

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Exhibit Number	Description
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 (incorporated by reference to Exhibit 10.26.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395).
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 (incorporated by reference to Exhibit 10.26.6 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395).
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 (incorporated by reference to Exhibit 10.26.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395).
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 (incorporated by reference to Exhibit 10.26.8 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395).
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 (incorporated by reference to Exhibit 10.26.9 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395).

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Exhibit Number	Description
10.26.10	Form of Make-up Grant Award Agreement under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated January 1, 2012 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2013; File No. 001-32395).
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).
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).
10.36	Offer letter from ConocoPhillips to Matthew J. Fox, dated November 18, 2011 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2013; 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.

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Exhibit Number	Description
23.2*	Consent of DeGolyer and MacNaughton.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32*	Certifications pursuant to 18 U.S.C. Section 1350.
99*	Report of DeGolyer and MacNaughton.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Labels Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.

* Filed herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONOCOPHILLIPS

February 25, 2014	*/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 25, 2014, 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/ Gay Huey Evans Gay Huey Evans	Director
/s/ Jody L. Freeman Jody L. Freeman	Director
/s/ Robert A. Niblock Robert A. Niblock	Director
/s/ Harald J. Norvik Harald J. Norvik	Director
/s/ William E. Wade, Jr. William E. Wade, Jr.	Director