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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2011

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 No. 1-8968

ANADARKO PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**76-0146568**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1201 Lake Robbins Drive, The Woodlands, Texas 77380-1046
(Address of principal executive offices)

Registrant's telephone number, including area code **(832) 636-1000**

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.10 per share	New York Stock Exchange

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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 ☒ 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 ☐ No ☒

The aggregate market value of the Company's common stock held by non-affiliates of the registrant on June 30, 2011 was $38.1 billion based on the closing price as reported on the New York Stock Exchange.

The number of shares outstanding of the Company's common stock at January 31, 2012, is shown below:

Title of Class	**Number of Shares Outstanding**
Common Stock, par value $0.10 per share	498,427,854

Part of Form 10-K	**Documents Incorporated By Reference**
Part III	Portions of the Proxy Statement for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 15, 2012 (to be filed with the Securities and Exchange Commission prior to April 5, 2012).

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PART I

Items 1 and 2. Business and Properties

GENERAL

Anadarko Petroleum Corporation is among the world's largest independent exploration and production companies, with over 2.5 billion barrels of oil equivalent (BOE) of proved reserves at December 31, 2011. Anadarko's mission is to deliver a competitive and sustainable rate of return to shareholders by exploring for, acquiring, and developing oil and natural-gas resources vital to the world's health and welfare. Anadarko's asset portfolio is aimed at delivering long-term value to stakeholders by combining a large inventory of development opportunities in the United States onshore with high-potential worldwide offshore exploration and development activities.

Anadarko's asset portfolio includes positions in onshore resource plays in the Rocky Mountains region, the southern United States, and the Appalachian basin. The Company is also among the largest independent producers in the deepwater Gulf of Mexico, and has production and exploration activities worldwide including positions in high-potential basins located in East and West Africa, Algeria, China, Alaska, and New Zealand.

Anadarko is committed to producing energy in a manner that protects the environment and public health. Anadarko's focus is to deliver resources to the world while upholding the Company's core values of integrity and trust, servant leadership, commercial focus, people and passion, and open communication in all business activities.

Anadarko's primary business segments are managed separately due to distinct operational differences and unique technology, and distribution and marketing requirements. The Company's three reporting segments are as follows:

Oil and gas exploration and production—This segment explores for and produces natural gas, crude oil, condensate, and natural gas liquids (NGLs).

Midstream—This segment provides gathering, processing, treating, and transportation services to Anadarko and third-party oil and natural-gas producers. The Company owns and operates gathering, processing, treating, and transportation systems in the United States.

Marketing—This segment sells much of Anadarko's production, as well as production purchased from third parties. The Company actively markets oil, natural gas, and NGLs in the United States, and actively markets oil from Algeria, China, and Ghana.

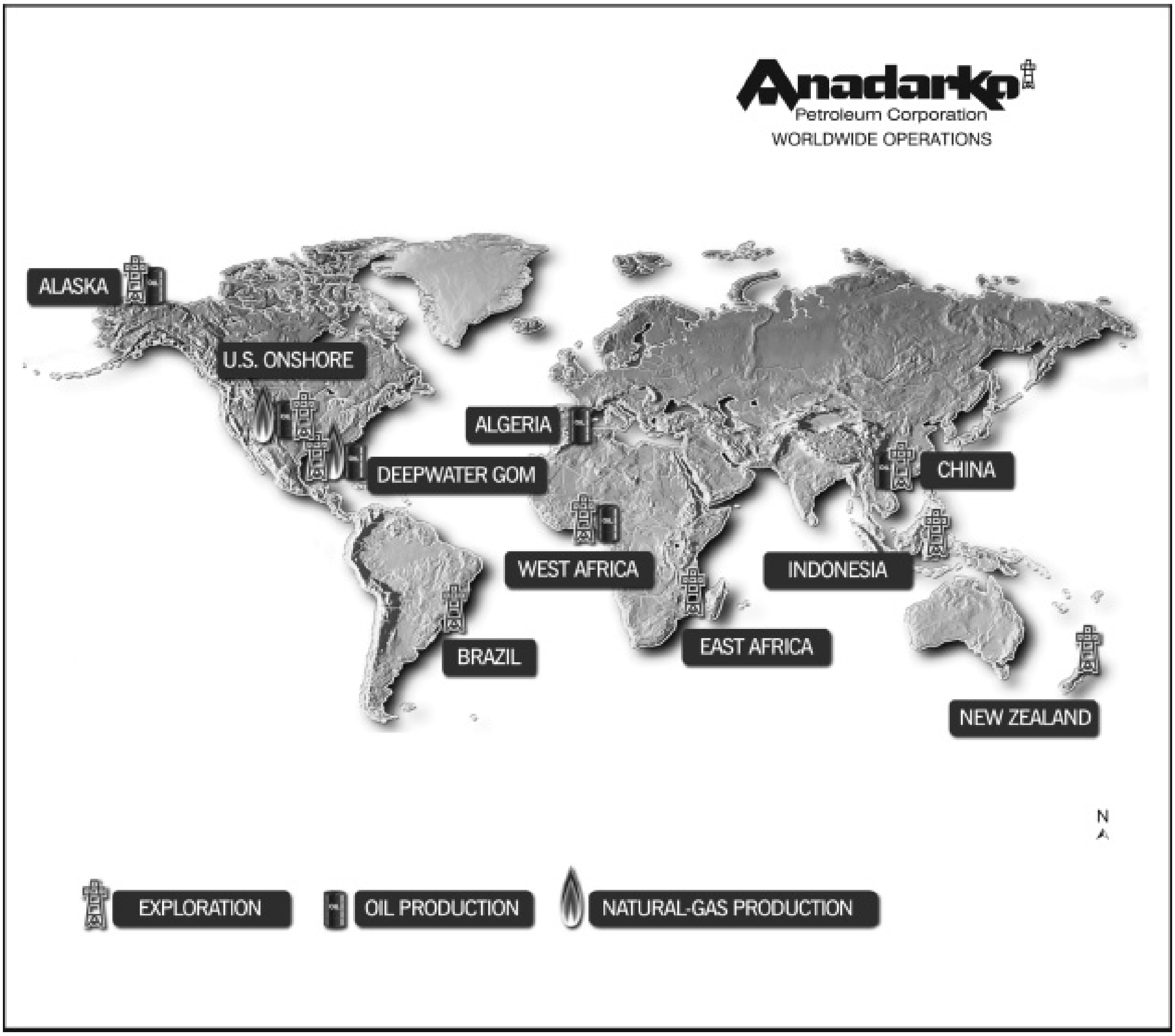
Unless the context otherwise requires, the terms "Anadarko" or "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. The Company's corporate headquarters is located at 1201 Lake Robbins Drive, The Woodlands, Texas 77380-1046, and its telephone number is (832) 636-1000.

Available Information The Company files or furnishes Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, registration statements, and other items with the Securities and Exchange Commission (SEC). Anadarko provides access free of charge to all of these SEC filings, as soon as reasonably practicable after filing or furnishing, on its website located at www.anadarko.com/Investor/Pages/SECFilings.aspx. The Company will also make available to any stockholder, without charge, copies of its Annual Report on Form 10-K as filed with the SEC. For copies of this report, or any other filing, please contact Anadarko Petroleum Corporation, Investor Relations Department, P.O. Box 1330, Houston, Texas 77251-1330 or call (832) 636-1216.

In addition, the public may read and copy any materials Anadarko files with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers, like Anadarko, that file electronically with the SEC.

OIL AND GAS PROPERTIES AND ACTIVITIES

The map below illustrates the locations of Anadarko's oil and natural-gas exploration and production operations.



United States

Overview Anadarko's operations in the United States include oil and natural-gas exploration and production onshore in the Lower 48 states, onshore Alaska, and the deepwater Gulf of Mexico. The Company's operations in the United States accounted for 87% of total sales volumes during 2011 and 90% of total proved reserves at year-end 2011.

Onshore In 2011, the Company's shale plays delivered a year-over-year sales-volume increase of almost 200%. Shale volumes now account for slightly more than 10% of the Company total sales volumes, which is up from less than one percent two years ago. Shales also represent about five percent of Anadarko's total proved reserves.

Rocky Mountains Region Anadarko's Rocky Mountains Region (Rockies) properties are located in Colorado, Utah, and Wyoming and are a combination of oil and natural-gas plays, with significant growth and capital investment in areas that offer higher liquids yields (liquids-rich areas). Anadarko operates approximately 14,300 wells and has an interest in approximately 9,500 non-operated wells in the Rockies. Anadarko operates fractured carbonate/shale reservoirs, tight gas assets, and coalbed methane (CBM) natural-gas assets, as well as enhanced oil recovery (EOR) projects within the region. The Company also has fee ownership of mineral rights under approximately 8 million acres that passes through Colorado and Wyoming and into Utah (Land Grant). Management considers the Land Grant a significant competitive advantage to Anadarko because it offers liquids-rich drilling opportunities for the Company, and allows the Company to capture incremental royalty revenue from third-party activity in the area. Activities in the Rockies continue to focus on expanding the existing fields to increase production and adding proved reserves through infill drilling and down-spacing operations, re-completions, and re-fracture stimulations of existing wells. During 2011, total sales volumes in the Rockies increased 10% over 2010, with an 18% increase in liquids volumes. In 2011, the Company drilled 1,029 wells in the Rockies and plans to accelerate its drilling program in the region in 2012.

In 2011, the Company was dedicated to the development of new horizontal opportunities in the Niobrara and other formations in the Denver-Julesburg basin, which includes the Wattenberg field. The Niobrara is a naturally fractured carbonate formation that holds liquids and natural gas. During 2011, the Company drilled 33 horizontal wells in the Wattenberg field, focusing on liquids-rich areas in the Niobrara and Codell formations. The Company also drilled 17 horizontal wells in the Denver-Julesburg basin (outside the Wattenberg field) and the Powder River basin as part of the horizontal program.

The Wattenberg field is a liquids-rich area where Anadarko operates over 5,300 wells. During 2011, the Company drilled 433 vertical/directional wells in the Wattenberg field and increased sales volumes 19% compared to 2010, with a year-over-year 32% increase in liquids volumes. Horizontal drilling results in the Wattenberg field have shown strong initial production rates with average liquids yields of approximately 70%. The Company has also identified 1,200 to 2,700 future potential drilling locations in the Niobrara and Codell sandstone that provide substantial opportunity for expanding Anadarko's activity in these formations. The competitive advantage provided by mineral ownership in the Land Grant, the liquids-rich reservoirs, strong well performance, low development costs, and expandable midstream infrastructure each provide tangible benefits to the Company and position it to accelerate its horizontal drilling program in the Wattenberg field. The Company plans to increase its activity by deploying seven horizontal rigs and drilling approximately 160 horizontal wells in 2012.

The Greater Natural Buttes area in eastern Utah is one of the Company's major tight gas assets, where the Company is focusing on liquids-rich areas. The Company utilizes refrigeration and cryogenic processing facilities to extract natural-gas liquids from the gas stream. The Company operates over 2,200 wells in the Greater Natural Buttes area, drilled 288 wells in 2011, and increased year-over-year sales volumes from the area by 23%. The Company has identified more than 6,000 potential locations in the Greater Natural Buttes area for future development in the Mesaverde formation. Many of these locations are infill drilling opportunities focused on down-spacing from 40-acre well density to 10-acre well density. Anadarko drilled and completed the lower Mesaverde Blackhawk interval in 56 new development wells during 2011. This is a capital-efficient program with incremental development costs of approximately $0.50 per-Mcf equivalent. The Company's other tight-gas assets in the Rockies are located in the Greater Green River area in Wyoming. Anadarko is expanding the cryogenic facilities at its Chipeta plant to increase contracted cryogenic processing capacity to 500 MMcf/d by the third quarter of 2012. This expansion is expected to result in an incremental gross recovery of over 15,000 barrels of NGLs per day.

Anadarko also operates multiple CBM properties in the Rockies. CBM is natural gas that is generated and stored within coal seams. To produce CBM, water is extracted from the coal seam, resulting in reduced pressure and the release of natural gas which flows to the wellhead. Anadarko's primary CBM properties are located in the Powder River basin and Atlantic Rim areas in Wyoming and the Helper and Clawson fields in Utah. Anadarko operates approximately 4,000 low-cost CBM wells and has an interest in approximately 4,500 non-operated CBM wells in the Rockies. In 2011, Anadarko reduced development activity in its CBM program as the Company continued to allocate its capital spending toward its liquids-rich opportunities. A reduction in CBM development activity is expected to continue in 2012 as a result of low natural-gas prices.

The Company's EOR operations increase the amount of oil that can be produced from mature reservoirs after primary and water-flood recovery methods have been completed. During 2011, the Company continued to pursue development of its Rockies EOR assets at the Monell and Salt Creek fields in Wyoming. Monell field development is near completion with a small drilling program scheduled to finish edge-pattern development, and some minor infrastructure investments planned for 2012 to enhance carbon dioxide flooding operations. Throughout 2012, the Company plans to progress the tertiary recovery operations at Salt Creek, which the Company has been continuously implementing since 2003.

Southern and Appalachia Region Anadarko's Southern and Appalachia Region properties are primarily located in Texas, Pennsylvania, Louisiana, Kansas, and Ohio. Operations in these areas are focused on finding and developing both natural gas and liquids from shales, tight sands, and fractured-reservoir plays.

Anadarko holds an interest in approximately 705,000 net acres in shale and other emerging-growth plays throughout the Southern and Appalachia Region. These plays include the Eagleford/Pearsall shales in southwest Texas, the Marcellus shale in north-central Pennsylvania, the Bone Spring formation and Avalon shale in the Delaware basin of West Texas, the Haynesville shale in East Texas and Louisiana, and the Utica shale in eastern Ohio. Anadarko also has tight gas and/or fractured-reservoir operations in the Bossier, Haley, Carthage, Chalk, South Texas and Ozona areas in Texas, and the Hugoton area in southern Kansas.

In 2011, the Company drilled 442 wells and completed 364 wells in the Southern and Appalachia Region. Over 97% of the operated wells were drilled horizontally. By utilizing modernized drilling rigs and experienced crews, the region continued to experience improved drilling efficiencies in every area with respect to cycle times, while also drilling longer lateral lengths. Due to lower natural-gas prices, the Company is focusing its drilling activity in liquids-rich areas, such as the Eagleford shale and the Bone Spring and Avalon formations.

The Eagleford shale continues to be one of the Company's most economic plays, capable of generating returns in excess of 100%. In the first quarter of 2011, Anadarko entered into a joint-venture agreement that conveyed 33.3% of the Company's Eagleford and Pearsall shale assets to a third party. The third party acquired 96,000 net acres (80,000 acres within the Eagleford shale and the underlying Pearsall shale rights, and an additional 16,000 acres limited to Pearsall shale rights only) in exchange for funding $1.6 billion of Anadarko's future drilling costs. The funding began in the second quarter of 2011 and covered $500 million of the Company's 2011 development costs. The funding covers 90% of Anadarko's development costs in subsequent years up to a $650 million annual limit. Based on expected activity, the third-party funding is expected to be fully utilized in the second half of 2013. Anadarko currently holds approximately 405,500 gross and 193,000 net acres with an average working interest of approximately 49% in this area. During 2011, the Company operated an average of nine rigs, which spud 228 horizontal wells and completed 197 wells. The Company began the year producing 14,300 net (27,000 gross) barrels of oil equivalent per day (BOE/d) and ended the year at over 27,400 net (77,000 gross) BOE/d, after completing over 3,200 fracturing stages during the year.

In the Appalachian basin, where the Marcellus shale is being developed, 134 operated horizontal wells were spud and 73 wells were completed utilizing a fleet that averaged seven rigs for the year. Anadarko also participated in 148 new horizontal wells and 135 completions as a non-operating partner in the area. Anadarko has a joint-venture agreement that permits a third party to participate with the Company as a 32.5% partner in the Company's Marcellus shale assets in exchange for funding $1.4 billion of Anadarko's drilling costs. The third party funded 100% of the Company's 2010 development costs and 90% of these costs in 2011. The third party will continue to fund 90% of the development costs until the funding commitment is exhausted, which is anticipated to occur in 2012. Anadarko's production in the area increased from a net 2010 year-end exit rate of 84 million cubic feet per day (MMcf/d) of natural gas to a net year-end exit rate of 230 MMcf/d.

During 2011, the Company accumulated over 370,000 gross acres in the prospective liquids-rich area of the eastern Ohio Utica shale in the Appalachian basin. Two Utica horizontal pilot wells reached total depth in the fourth quarter of 2011 and Anadarko plans to accelerate the pilot and testing program in 2012.

Anadarko owns 330,000 net acres in the Delaware basin, which has seen significant drilling activity, primarily targeting the liquids-rich Bone Spring formation and Avalon shale. In 2011, Anadarko spud 50 operated wells, participated in 27 non-operated wells, and completed 54 operated wells and 27 non-operated wells in the area. Drilling and well performance continue to improve with well tests producing in excess of 2,000 BOE/d. The Company had four rigs drilling in the Bone Spring formation and one rig drilling in the Avalon shale at year-end 2011.

Alaska Anadarko's oil and natural-gas production and development activity in Alaska is concentrated primarily on the North Slope. Development activity continued at the Colville River Unit through 2011 with eight wells drilled. In 2012, the Company anticipates participating in approximately 12 development wells and the sanctioning of the Alpine West satellite development.

Gulf of Mexico In the Gulf of Mexico, Anadarko owns an average 64% working interest in 487 blocks. The Company operates seven active floating platforms, holds interests in 34 producing fields, and is in the process of delineating and developing six additional fields in the area.

Following a period of significantly reduced activity as a result of the drilling moratorium in 2010, during 2011, the Company resumed an active deepwater exploration and appraisal program in the Gulf of Mexico and is continuing to take advantage of existing infrastructure to accelerate resource development at reduced costs. Anadarko made its first post-moratorium deepwater discovery at the Cheyenne East prospect, which is being developed as a tieback to the Independence Hub (IHUB) and is expected to produce 60 MMcf/d of natural gas. First production from this well is expected by March 2012. The Company also completed a workover at the Spiderman IHUB well, resulting in natural-gas production at a rate in excess of 90 MMcf/d. In 4.5 years since first production, aggregate IHUB production surpassed one trillion cubic feet (Tcf) in early 2012. In Green Canyon Block 903, the Heidelberg appraisal well (44% operated working interest) began drilling in October 2011, and was declared successful in February 2012. The Company plans to sidetrack the well to evaluate the down-dip extent of the field.

During 2011, Anadarko continued to advance the Lucius field development. The unitization agreement for the Anadarko-operated Lucius field was signed during the second quarter of 2011, and the Lucius project was sanctioned during the fourth quarter of 2011 with first production expected in 2014. A production-handling agreement to process natural gas from the Hadrian South field at the Lucius facility was executed with the Hadrian South co-venturers, and will add additional value to the Lucius development. The Company completed a successful well test at Lucius, which showed that the well is capable of flowing in excess of 15,000 barrels per day (Bbls/d) of oil and that the main pay intervals are well connected. Lucius will be developed with a truss spar floating production facility with the capacity to produce in excess of 80,000 Bbls/d of oil and 450 MMcf/d of natural gas. The spar is currently under construction and will be the largest of Anadarko's operated spars. The Company plans to have an active drilling program in the area beginning in 2012, with plans to drill its Spartacus prospect during the year.

Anadarko continued advancing its development project at Caesar/Tonga. The Company completed and tested three wells that each demonstrated facility-constrained flow rates of approximately 15,000 Bbls/d of oil. First production is expected by mid-2012.

During 2011, Anadarko participated in the drilling of the Coronado #1 exploration well (15% working interest), located in Walker Ridge Block 143. The well spud in October 2011 and was plugged and abandoned as a result of unanticipated geopressure in the shallow section. At year-end 2011, seismic was being reviewed to determine a new well location. In June 2011, the Kakuna #1 subsalt exploration well spud. Anadarko has an option to acquire a 6.25% interest or an overriding royalty interest in the well, which is located in Green Canyon Block 505, north of the Company's Caesar/Tonga development. In addition, the Vito NE appraisal well (20% non-operated working interest), located in Mississippi Canyon Block 940, spud in early 2012 and will test the northeast flank of the Vito discovery.

Due to the drilling moratorium, Anadarko redeployed its deepwater rigs to other parts of the world but retained the *Ensco 8500* under a long-term contract for operations in the Gulf of Mexico. The Gulf of Mexico has regained momentum and the Bureau of Safety and Environmental Enforcement (BSEE) is approving drilling permits, which has prompted Anadarko to execute contracts for the *Ensco 8505* rig, with delivery scheduled for the second quarter of 2012 and the *Ensco 8506* rig, with delivery in the fourth quarter of 2012. Both the *Ensco 8500* and the *Ensco 8505* are shared rig contracts between Anadarko and other Gulf of Mexico operators. Also, the *Transocean Spirit* rig, currently working in West Africa, will be mobilized to the Gulf of Mexico in the latter part of 2012 to service the Company's oil development projects and exploration activities in the Gulf of Mexico. Anadarko expects exploration and appraisal activities to return to pre-moratorium levels in 2012. In addition, Anadarko signed long-term lease agreements for two new-build state-of-the-art drillships. The *Ocean BlackHawk* is expected to be delivered in late 2013 and the *Ocean BlackHornet* is expected to be delivered in early 2014. These rigs are dual-activity and dual blowout-prevention rigs, reflecting Anadarko's focus on continuing to enhance operational efficiency.

International

Overview The Company's international oil and natural-gas production and development operations are located primarily in Algeria, Ghana, and China. The Company also has exploration acreage in Ghana, Mozambique, Brazil, Liberia, Sierra Leone, Kenya, Cote d'Ivoire, New Zealand, Indonesia, and other countries. International locations accounted for 13% of Anadarko's total sales volumes and 27% of sales revenues during 2011, as well as 10% of total proved reserves at year-end 2011. Anadarko drilled 33 wells in international areas in 2011, which included natural-gas discoveries in Mozambique and oil discoveries in Ghana. In 2012, the Company expects to drill approximately 25 development and 25 exploration wells at various international locations.

Algeria Anadarko is engaged in development and production activities in Algeria's Sahara Desert in Blocks 404 and 208. Currently, all production is from fields located in Block 404, which produce through the Hassi Berkine South and Ourhoud Central Production Facilities (CPF). The El Merk project progressed to approximately 88% overall completion at December 31, 2011, and remains on target for initial production in 2012 with significant gross volumes expected at the facility near the end of 2012. The percentage of overall completion captures the progress of ongoing construction work at the El Merk CPF and associated infrastructure such as offsite facilities, export pipelines, and power transmission lines. During 2011, 16 development wells were drilled in Blocks 404 and 208. The Company expects 2012 development drilling activity to be similar to 2011 levels, with continued focus on El Merk drilling.

Contracts and Partners Since October 1989, the Company's operations in Algeria have been governed by a Production Sharing Agreement (PSA) between Anadarko, two third parties, and Sonatrach, the national oil and gas company of Algeria. Anadarko's interest in the PSA for Blocks 404 and 208 is 50% before participation at the exploitation stage by Sonatrach. The Company has two partners, each with a 25% interest, also prior to participation by Sonatrach. Under the terms of the PSA, oil reserves that are discovered, developed, and produced are shared by Sonatrach, Anadarko, and the remaining two partners. Sonatrach is responsible for 51% of development and production costs, Anadarko is responsible for 24.5%, and its two partners are each responsible for 12.25%. Anadarko and its partners have completed the exploration program on Blocks 404 and 208 and now participate only in development activity on these blocks. Anadarko and its joint-venture partners funded Sonatrach's share of exploration costs and are entitled to recover these exploration costs from production during the development phase.

Exceptional Profits Tax In July 2006, the Algerian parliament approved legislation establishing an exceptional profits tax on foreign companies' Algerian oil production. In December 2006, regulations regarding this legislation were issued. These regulations provide for an exceptional profits tax imposed on gross production at rates of taxation ranging from 5% to 50% based on average daily production volumes for each calendar month in which the price of Brent crude averages over $30 per barrel. Exceptional profits tax applies to the full value of production rather than to the amount in excess of $30 per barrel.

In response to the Algerian government's imposition of the exceptional profits tax, the Company notified Sonatrach of its disagreement with the collection of the exceptional profits tax. The Company believes that the PSA provides fiscal stability through several provisions that require Sonatrach to pay all taxes and royalties. To facilitate discussions between the parties in an effort to resolve the dispute, in October 2007 the Company initiated a conciliation proceeding on the exceptional profits tax as provided in the PSA. The Conciliation Board issued its non-binding recommendation in November 2008. In February 2009, the Company initiated arbitration against Sonatrach with regard to the exceptional profits tax by submitting a notice of arbitration to Sonatrach. The arbitration hearing on the merits of the claims presented by Anadarko took place in June 2011 and the Company anticipates the issuance of the arbitration panel's decision in the near term. Any decision issued by the arbitration panel is binding on the parties.

Ghana Anadarko's exploration and development activities in Ghana are located offshore in the West Cape Three Points Block and the Deepwater Tano Block. In December 2010, 3.5 years following discovery, the Company and its partners achieved first oil from the Jubilee field. The Company and its partners completed execution of the Phase 1 development program and tied back 17 wells to the floating production, storage, and offloading vessel (FPSO) at the Jubilee field. The gross oil production level was approximately 70,000 Bbls/d at year-end 2011 from eight producing wells. Completion issues required a side-track of one of the original nine Phase 1 production wells in the fourth quarter of 2011 and two or three other producing wells have been identified as possible side-track operations in 2012. Once the completion issues have been resolved, production is expected to increase toward facility capacity of 120,000 Bbls/d. Work is also underway to execute the next phase of development which will tie back another eight wells to the Jubilee FPSO during 2012 and 2013.

During 2011, the Company participated in 10 exploration and appraisal wells outside the Jubilee field, including the Akasa #1 discovery well in the West Cape Three Points Block (32% non-operated interest), two Teak discovery wells, and one Teak appraisal well to the Teak #1 discovery. The successful Teak appraisal well confirmed a northern extension of the discovery. The Company also participated in two successful Enyenra appraisal wells in the Deepwater Tano Block (18% non-operated working interest) and an additional appraisal of the Tweneboa discovery. A drillstem test (DST) conducted on the Tweneboa #2 well in the bottom oil leg of the reservoir and the DST performed at the Tweneboa #4 well confirmed the connectivity of the two wells. The Ntomme #2 was spud in late 2011 and reached total depth in 2012. This successful appraisal well tested the same targets discovered in the Tweneboa #3ST well and encountered oil pay in excellent-quality sandstone reservoirs. In 2012, the Company plans to participate in up to four exploration and appraisal wells in Ghana.

The Company and its partners anticipate declaration of commerciality for the Tweneboa/Enyenra/Ntomme field complex located in the Deepwater Tano Block during the second half of 2012 following completion of the appraisal program. In the West Cape Three Points Block, stand-alone FPSO and Jubilee tie-back development options are being evaluated to maximize the resource value from the Teak and Akasa discoveries.

Mozambique Anadarko operates two blocks (one onshore and one offshore) in Mozambique totaling approximately six million gross acres. In 2011, the Company drilled two natural-gas discoveries (Tubarão and Camarão) and two successful appraisal wells (Barquentine #2 and Barquentine #3) in the Offshore Area 1 of the Rovuma basin where Anadarko holds a 36.5% working interest. In 2012, the Lagosta #2 and Lagosta #3 appraisal wells successfully appraised discoveries at Lagosta and Camarão. To date, the Company has eight successful wells in the complex, including the Windjammer, Lagosta, Barquentine and Camarão discoveries. As a result, the Company and its partners are continuing to advance a liquefied natural gas (LNG) development, which is being designed to consist of an initial two 5-million-tonne-per-annum trains. Anadarko plans to construct a flexible offshore production system to collect gas from the wells located approximately 35 miles (56 kilometers) offshore, which will deliver gas to the liquefaction plant onshore. Pre-FEED (front-end engineering and design) activities are complete and the Company expects to begin FEED work around the middle of 2012. The Company expects to reach a final investment decision at approximately year-end 2013, with first cargo sales targeted for late 2018.

Also during 2011, Anadarko acquired two new 3D seismic datasets which have led to a growing number of high-potential prospects in other areas of the Offshore Area 1. Early in 2012, Anadarko mobilized a second deepwater drillship to Mozambique to accelerate the planned exploration and appraisal activities, which include an extensive reservoir testing program and up to seven exploration and appraisal wells in 2012.

China Anadarko's development and production activities in China are located offshore in Bohai Bay. Development drilling was ongoing throughout 2011, and Anadarko drilled 19 wells during the year including eight side-tracks of low oil-rate/high water-cut producers. The majority of the wells were drilled from the platform expansion decks, which were installed as part of an initiative to sustain continued plateau production. An exploration well in the South China Sea is expected to spud in mid-2012. Consistent with the terms of the Petroleum Contract, the Company is preparing to transfer operatorship of the Bohai Bay development to China National Offshore Oil Corporation at the end of 2012.

Brazil Anadarko holds exploration interests in approximately 750,000 gross acres in six blocks located offshore Brazil in the Campos and Espírito Santo basins. In these areas, Anadarko drilled two appraisal wells in 2011. In Block BM-C-32 (33% non-operated working interest) in the Campos basin, the successful Itaipu #2 pre-salt appraisal well established a fluid contact and appears to have successfully extended the accumulation 394 feet downdip from the Itaipu discovery well, which is located four miles to the northwest. The appraisal well significantly increases the areal extent of the Itaipu field. In Block BM-C-29 (50% working interest), the Ituana appraisal well was plugged and abandoned in 2012. The Company is reviewing the results of the well as part of the evaluation of the Ituana post-salt discovery. Anadarko expects to drill up to four exploration and appraisal wells in Brazil during 2012, including the Wahoo #4 appraisal well in Block BM-C-30 (30% operated working interest).

During 2011, the Company began marketing its Brazilian properties and a sale is possible in 2012 subject to receiving acceptable pricing and terms and obtaining regulatory approval.

Liberia The Company currently operates four blocks in offshore Liberia totaling approximately 3.3 million exploration acres in the Liberian basin. Multiple Cretaceous stratigraphic leads, similar to the Jubilee Mahogany fan, have been identified on these blocks. The Montserrado well was drilled in 2011 on Block LB-15 and encountered good-quality, water-bearing sands in the main objective and 27 net feet of pay in a secondary objective. The well was plugged and abandoned and the results are being incorporated into the Company's geologic data for future exploration in the Liberian basin. Plans for 2012 include the incorporation of the drilling results into the 3D seismic on Blocks 15, 16, and 17, as well as the evaluation of the newly acquired 3D seismic in the LB-10 Block.

Sierra Leone Anadarko operates and has a 55% participating interest in Block SL-07B-11 in offshore Sierra Leone encompassing approximately 1.2 million gross acres. Multiple Upper Cretaceous fan-type prospects have been identified in the lightly explored Liberian basin. The Jupiter #1 well, spud in the fourth quarter of 2011, targeted a large Cretaceous fan channel complex similar to the Enyenra and Tweneboa discoveries in Ghana. In 2012, the Jupiter #1 discovery well encountered hydrocarbon pay and has been preserved for possible re-entry, as the area will likely require additional evaluation. The Mercury #2 well, which will be drilled subsequent to Jupiter #1, will appraise the Mercury #1 discovery well that was announced as a discovery in 2010.

Kenya Anadarko operates and has a 50% participating interest in five deepwater blocks offshore Kenya encompassing approximately 7.5 million gross acres. The Company has completed 2D and 3D seismic programs and evaluation is currently taking place with potential drilling possible in late 2012 or early 2013.

Côte d'Ivoire During 2011, Anadarko and its partners began interpreting new 3D seismic data on two deepwater exploration blocks totaling approximately 850,000 gross acres offshore Côte d'Ivoire. Multiple Upper Cretaceous fan-type prospects have been identified on the 2D and 3D seismic. The Kosrou #1 well, spud in January 2012 on Block CI 105 (50% operated interest), has multiple targets within a large Cretaceous fan located south and east of the Company's 2009 South Grand Lahou-1X well, which encountered thin sands with shows in the target. The Paon prospect located on Block CI 103 (40% non-operated interest) will be drilled following the Kosrou well. The geology on the block appears similar to that of the Jubilee, Enyenra, and Tweneboa discoveries in Ghana. In 2012, Anadarko purchased approximately 500,000 gross acres in Blocks CI 515 and CI 516 (45% operated interest).

New Zealand Anadarko operates approximately 11.5 million exploration acres in the Taranaki and Canterbury basins in New Zealand. A 3D seismic survey of approximately 1,100 square miles was completed on the Taranaki Block in 2011, and a 2D seismic survey of approximately 2,400 miles was acquired over the Canterbury Blocks. Two exploration wells, one on each block, are planned for late 2012 subject to rig availability.

Indonesia Anadarko has participating interests in approximately 3.4 million gross exploration acres in Indonesia through a combination of one operated and two non-operated Production Sharing Contracts. In 2012, the Company began marketing its Indonesian properties for sale.

Other Anadarko also has exploration projects in other overseas, new-venture areas including Morocco, Tunisia, and South Africa.

Proved Reserves

Estimates of proved reserves volumes owned at year end, net of third-party royalty interests, are presented in billion cubic feet (Bcf), at a pressure base of 14.73 pounds per square inch for natural gas and in millions of barrels (MMBbls) for oil, condensate, and NGLs. Total volumes are presented in millions of barrels of oil equivalent (MMBOE). For this computation, one barrel is the equivalent of 6,000 cubic feet of natural gas. Shrinkage associated with NGLs has been deducted from the natural-gas reserve volumes.

Disclosures by geographic area include United States and International. The International geographic area includes proved reserves located in Algeria, Ghana, and China, which by country and in total represents less than 15% of the Company's total proved reserves.

Summary of Proved Reserves

	Natural Gas (Bcf)	Oil and Condensate (MMBbls)	NGLs (MMBbls)	Total (MMBOE)
As of December 31, 2011				
Proved				
Developed				
United States	**6,113**	**352**	**267**	**1,638**
International	**—**	**173**	**—**	**173**
Undeveloped				
United States	**2,252**	**184**	**94**	**653**
International	**—**	**62**	**13**	**75**
Total proved	**8,365**	**771**	**374**	**2,539**
As of December 31, 2010				
Proved				
Developed				
United States	5,982	303	222	1,523
International	—	150	—	150
Undeveloped				
United States	2,135	195	85	635
International	—	101	13	114
Total proved	8,117	749	320	2,422
As of December 31, 2009				
Proved				
Developed				
United States	5,884	300	199	1,480
International	—	144	—	144
Undeveloped				
United States	1,880	200	61	574
International	—	89	17	106
Total proved	7,764	733	277	2,304

The Company's year-end 2011 product mix for proved reserves was 55% natural gas, 30% oil and condensate, and 15% NGLs; compared to a year-end 2010 product mix of 56% natural gas, 31% oil and condensate, and 13% NGLs; and a year-end 2009 product mix of 56% natural gas, 32% oil and condensate, and 12% NGLs.

The Company's estimates of proved developed reserves, proved undeveloped reserves (PUDs), and total proved reserves at December 31, 2011, 2010, and 2009, and changes in proved reserves during the last three years are presented in the *Supplemental Information on Oil and Gas Exploration and Production Activities (Supplemental Information)* under Item 8 of this Form 10-K.

The Company has not filed information with a federal authority or agency with respect to its estimated total proved reserves at December 31, 2011. Annually, Anadarko reports gross proved reserves of operated properties in the United States to the U.S. Department of Energy; these reported reserves are derived from the same data used to estimate and report proved reserves in this Form 10-K.

Also presented in the *Supplemental Information* are the Company's estimates of future net cash flows and discounted future net cash flows from proved reserves. See *Operating Results* and *Critical Accounting Estimates* under Item 7 of this Form 10-K for additional information on the Company's proved reserves.

Changes in PUDs Significant changes to PUDs occurring during 2011 are summarized in the table below. Revisions of prior estimates reflect the addition of new PUDs associated with current development plans, revisions to prior PUDs, revisions to infill drilling development plans, as well as the transfer of PUDs to unproved reserve categories due to changes in development plans during the period. These PUDs changes reflect the ongoing evaluation of Anadarko's asset portfolio and alignment with current-year changes to development plans. The Company's year-end development plans are consistent with SEC guidelines for PUDs development within five years unless specific circumstances warrant a longer development time horizon.

MMBOE	
PUDs at December 31, 2010	**749**
Revisions of prior estimates	**60**
Extensions, discoveries, and other additions	**112**
Conversion to developed	**(171)**
Sales	**(22)**
PUDs at December 31, 2011	**728**

PUDs Conversion In 2011, the Company converted 171 MMBOE, or 23% of the total year-end 2010 PUDs, to developed status. Approximately 58% of PUDs conversions occurred in onshore U.S. assets, 26% in international assets, and the remaining 16% in Gulf of Mexico assets.

The majority of PUDs conversions occurred as a result of ongoing development activities in the Rockies and in the liquids-rich areas of the Southern and Appalachia Region. Approximately 96 MMBOE of PUDs were converted to developed reserves in these areas. The conversion of an additional 45 MMBOE of PUDs occurred in the international areas, most of which are associated with completed production wells in the El Merk project of Algeria where the overall project was approximately 88% complete at December 31, 2011. Another 26 MMBOE of PUDs converted to developed reserves were associated with ongoing development in the Caesar/Tonga project in the U.S. Gulf of Mexico where three completed wells are awaiting tie-back to production facilities. The remaining converted PUDs were a result of development activity in Alaska.

Anadarko spent $900 million associated with the development of PUDs in 2011. Approximately 68% of total 2011 PUDs conversion capital related to domestic development programs in the Rockies and the Southern and Appalachia Regions. Approximately 12% related to the development of the Caesar/Tonga and Lucius projects in the Gulf of Mexico, and 10% related to development of the El Merk project in Algeria. The remaining 10% of 2011 PUDs development spending was associated with Alaska and other international development projects.

In 2010, the Company converted 103 MMBOE, or 15% of the total year-end 2009 PUDs to developed status. Approximately 65% of PUDs conversions occurred in onshore U.S. assets, 24% in international assets, and the remaining 11% in Gulf of Mexico assets. Anadarko spent $1.5 billion associated with the development of PUDs in 2010. Approximately 58% of total 2010 PUDs capital related to two major development projects, El Merk in Algeria and Jubilee in Ghana, and 29% related to domestic development programs in the Rockies and the Southern and Appalachia Regions. The remaining 13% of 2010 PUDs development spending was associated with Gulf of Mexico, Alaska, and other international development projects.

Development Plans The Company annually reviews all PUDs to ensure an appropriate plan for development exists. Typically, onshore U.S. PUDs are converted to developed reserves within five years of the initial proved reserves booking. Projects such as EOR, arctic development, deepwater development, and international programs may take longer than five years. All of the Company's onshore U.S. PUDs were scheduled to be developed within five years at December 31, 2011, with the exception of the Salt Creek EOR project, the annual development of which is limited by CO2 supply contract terms and the amount of work that can be physically completed.

The Company had 101 MMBOE of pre-2007 PUDs that remain undeveloped five years or more after initial disclosure as PUDs. Approximately 50% of these PUDs are located in Algeria and are being developed according to an Algerian government-approved plan. Nearly all of the Algerian PUDs are associated with the El Merk development project located in Block 208 in the Berkine basin. Site preparation was initiated in 2008 and construction of the El Merk CPF is continuing. As of year-end 2011, 85 wells have been drilled in the El Merk fields and drilling is continuing in 2012. The Reservoir Development Plan includes a total of 141 wells for full development. The overall El Merk project, including future drilling commitments, was approximately 88% complete at December 31, 2011. First oil production from the El Merk fields is expected to occur in 2012.

Another 42% of the Company's pre-2007 PUDs are associated with the Salt Creek EOR single-development project located in the Rockies. Since 2003, Anadarko has invested an average of $65 million per year to develop various phases of the Salt Creek integrated EOR project and will continue significant spending levels in the future to complete the development. All of the remaining pre-2007 PUDs are associated with Gulf of Mexico opportunities where development timing is influenced by seasonal restrictions and the depletion of reserves from existing completions. The Company expects to complete these opportunities over the next three years.

Technologies Used in Proved Reserve Estimation The Company's 2011 proved reserves additions were based on estimates generated through the integration of pertinent geological, engineering, and production data, utilizing technologies that have been demonstrated in the field to yield repeatable and consistent results as defined in the SEC regulations. Data used in these integrated assessments included information obtained directly from the subsurface through wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements such as seismic data. The tools used to interpret the data included proprietary and commercially available seismic processing software and commercially available reservoir modeling and simulation software. Reservoir parameters from analogous reservoirs were used to increase the quality of and confidence in the reserves estimates when available. The method or combination of methods used to estimate the reserves of each reservoir was based on the unique circumstances of each reservoir and the dataset available at the time of the estimate.

Internal Controls over Reserves Estimation Anadarko's estimates of proved reserves and associated future net cash flows were made solely by the Company's engineers and are the responsibility of management. The Company requires that reserves estimates be made by qualified reserves estimators (QREs), as defined by the Society of Petroleum Engineers' standards. The QREs are assigned to specific assets within the Company's regions. The QREs interact with engineering, land, and geoscience personnel to obtain the necessary data for projecting future production, net cash flows, and ultimate recoverable reserves. Management within each region approves the QREs' reserve estimates. All QREs receive ongoing education on the fundamentals of SEC reserves reporting through the Company's reserves manual and internal training programs administered by the Corporate Reserves Group (CRG).

The CRG ensures confidence in the Company's reserves estimates by maintaining internal policies for estimating and recording reserves in compliance with applicable SEC definitions and guidance. Compliance with the SEC reserves guidelines is the primary responsibility of Anadarko's CRG.

The CRG is managed through the Company's finance department, which is separate from its operating regions, and is responsible for overseeing internal reserves reviews and approving the Company's reserve estimates. The Director–Reserves Administration and the Corporate Reserves Manager manage the CRG and report to the Director–Corporate Planning. The Director–Corporate Planning reports to the Company's Senior Vice President, Finance and Chief Financial Officer, who in turn reports to the Chief Executive Officer. The Audit Committee of the Company's Board of Directors meets with management, members of the CRG, and the Company's independent petroleum consultants, Miller and Lents, Ltd. (M&L), to discuss matters and policies related to reserves.

The Company's principal engineer, who is primarily responsible for overseeing the preparation of proved reserves estimates, has over 25 years of experience in the oil and gas industry, including over 11 years as either a reserves evaluator or manager. Further professional qualifications include a degree in petroleum engineering, extensive internal and external reserves training, and asset evaluation and management. In addition, the principal engineer is an active participant in industry reserves seminars, professional industry groups, and has been a member of the Society of Petroleum Engineers for over 25 years.

Third-Party Procedures and Methods Review M&L reviewed the procedures and methods used by Anadarko's staff in preparing its internal estimates of proved reserves and future net cash flows at December 31, 2011. The purpose of the review was to determine that the procedures and methods used by Anadarko to estimate its proved reserves are effective and in accordance with the definitions contained in SEC regulations. The procedures and methods review by M&L was a limited review of Anadarko's procedures and methods and does not constitute a complete review, audit, independent estimate, or confirmation of the reasonableness of Anadarko's estimates of proved reserves and future net cash flows.

The review consisted of 17 fields which included major assets in the United States and Africa, and encompassed approximately 85% of the Company's estimates of proved reserves and associated future net cash flows at December 31, 2011. In each review, Anadarko's technical staff presented M&L with an overview of the data, methods, and assumptions used in estimating its 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 M&L to review its procedures and methods is to provide objective third-party input on the Company's procedures and methods and to gather industry information applicable to reserves estimation and reporting processes.

Sales Volumes, Prices, and Production Costs

The following table provides the Company's annual sales volumes, average sales prices, and average production costs per BOE for each of the last three years. The Company's sales volumes for 2011, 2010, and 2009 were 248 MMBOE, 235 MMBOE, and 220 MMBOE, respectively. Production costs are costs to operate and maintain the Company's wells and related equipment and include the cost of labor, well service and repair, location maintenance, power and fuel, transportation, other taxes, and production-related general and administrative costs. Additional information on volumes, prices and production costs is contained in *Financial Results* under Item 7 of this Form 10-K. Additional detail regarding production costs is contained in the *Supplemental Information* under Item 8 of this Form 10-K.

	Sales Volumes				**Average Sales Prices[1]**			
	Natural Gas (Bcf)	**Oil and Condensate (MMBbls)**	**NGLs (MMBbls)**	**Barrels of Oil Equivalent (MMBOE)**	**Natural Gas (Per Mcf)**	**Oil and Condensate (Per Bbl)**	**NGLs (Per Bbl)**	**Average Production Costs[2] (Per BOE)**
2011								
United States								
Greater Natural Buttes	**135**	**1**	**4**	**27**	**$ 3.58**	**$ 84.29**	**$ 52.04**	**$ 9.54**
Other United States	**717**	**47**	**23**	**190**	**3.93**	**97.93**	**54.28**	**9.48**
Total United States	**852**	**48**	**27**	**217**	**3.87**	**97.70**	**53.95**	**9.50**
International	**—**	**31**	**—**	**31**	**—**	**109.20**	**—**	**9.98**
Total	**852**	**79**	**27**	**248**	**3.87**	**102.24**	**53.95**	**9.55**
2010								
United States								
Greater Natural Buttes	107	1	4	23	$ 3.92	$ 66.50	$ 39.08	$ 9.65
Other United States	722	47	19	186	4.15	75.08	43.84	8.56
Total United States	829	48	23	209	4.12	74.96	43.07	8.68
International	—	26	—	26	—	78.52	—	7.56
Total	829	74	23	235	4.12	76.22	43.07	8.56
2009								
United States								
Greater Natural Buttes	100	1	3	21	$ 3.13	$ 48.84	$ 33.68	$ 9.43
Other United States	709	43	14	175	3.68	58.75	31.00	8.50
Total United States	809	44	17	196	3.61	58.56	31.42	8.59
International	—	24	—	24	—	59.01	—	6.01
Total	809	68	17	220	3.61	58.72	31.42	8.30

Bcf—billion cubic feet
Mcf—thousand cubic feet
Bbl—barrel

(1) Excludes the impact of commodity derivatives.

(2) Excludes ad valorem and severance taxes.

Delivery Commitments

The Company sells crude oil and natural gas under a variety of contractual agreements, some of which specify the delivery of fixed and determinable quantities. At December 31, 2011, Anadarko was contractually committed to deliver approximately 775 Bcf of natural gas to various customers in the United States through 2021. These contracts have various expiration dates with approximately 50% of the Company's current commitment to be delivered in 2012, and 85% by 2016. At December 31, 2011, Anadarko was also contractually committed to deliver approximately 8 MMBbls of crude oil to ports in Algeria and Ghana through 2012. The Company expects to fulfill these delivery commitments with existing proved developed and proved undeveloped reserves.

Drilling Program

The Company's 2011 drilling program focused on proven and emerging oil and natural-gas basins in the United States (onshore and deepwater Gulf of Mexico) and various international locations. Exploration activity in 2011 consisted of 224 gross completed wells, which included 216 onshore U.S. wells, three offshore Gulf of Mexico wells, and five international wells. Development activity in 2011 consisted of 1,843 gross completed wells, which included 1,813 onshore U.S. wells, two offshore Gulf of Mexico wells, and 28 international wells.

Drilling Statistics

The following table shows the number of oil and gas wells that completed drilling in each of the last three years.

	Net Exploratory			Net Development			
	Productive	**Dry Holes**	**Total**	**Productive**	**Dry Holes**	**Total**	**Total**
2011							
United States	**79.0**	**2.2**	**81.2**	**1,169.6**	**6.3**	**1,175.9**	**1,257.1**
International	**0.5**	**1.2**	**1.7**	**6.8**	**0.2**	**7.0**	**8.7**
Total	**79.5**	**3.4**	**82.9**	**1,176.4**	**6.5**	**1,182.9**	**1,265.8**
2010							
United States	84.3	1.2	85.5	1,027.9	3.6	1,031.5	1,117.0
International	—	3.6	3.6	11.2	—	11.2	14.8
Total	84.3	4.8	89.1	1,039.1	3.6	1,042.7	1,131.8
2009							
United States	30.6	5.0	35.6	587.2	7.3	594.5	630.1
International	—	3.3	3.3	10.7	—	10.7	14.0
Total	30.6	8.3	38.9	597.9	7.3	605.2	644.1

The following table shows the number of wells in the process of drilling or in active completion stages and the number of wells suspended or waiting on completion at December 31, 2011.

	Wells in the process of drilling or in active completion		Wells suspended or waiting on completion	
	Exploration	**Development**	**Exploration**	**Development**
United States				
Gross	39	286	172	346
Net	14.0	204.7	65.5	206.4
International				
Gross	5	2	34	—
Net	1.6	0.3	11.3	—
Total				
Gross	44	288	206	346
Net	15.6	205.0	76.8	206.4

Productive Wells

At December 31, 2011, the Company's ownership interest in productive wells was as follows:

	Oil Wells[1]	**Gas Wells**[1]
United States		
Gross	4,220	28,550
Net	3,292.4	17,777.7
International		
Gross	338	—
Net	85.7	—
Total		
Gross	4,558	28,550
Net	3,378.1	17,777.7

(1) Includes wells containing multiple completions as follows:

Gross	380	2,395
Net	347.4	1,899.1

Properties and Leases

The following schedule shows the developed lease, undeveloped lease, and fee mineral acres in which Anadarko held interests at December 31, 2011.

	Developed Lease		Undeveloped Lease		Fee Minerals		Total	
thousands of acres	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States								
Onshore	5,041	2,977	6,134	2,776	10,231	8,373	21,406	14,126
Offshore	340	167	2,403	1,645	—	—	2,743	1,812
Total United States	5,381	3,144	8,537	4,421	10,231	8,373	24,149	15,938
International	362	88	38,205	19,160	—	—	38,567	19,248
Total	5,743	3,232	46,742	23,581	10,231	8,373	62,716	35,186

At December 31, 2011, the Company had approximately 13 million net undeveloped lease acres scheduled to expire by December 31, 2012, if the Company does not establish production or take any other action to extend the terms. The Company plans to continue the terms of many of these licenses and concession areas through operational or administrative actions and does not expect a significant portion of the Company's net acreage position to expire before such actions occur.

MIDSTREAM PROPERTIES AND ACTIVITIES

Anadarko invests in midstream (gathering, processing, treating, and transportation) assets to complement its operations in regions where the Company has oil and natural-gas production. Through ownership and operation of these facilities, the Company is better able to manage costs, control the timing of bringing on new production, and enhance the value received for gathering, processing, treating, and transporting the Company's production. In addition, Anadarko's midstream business provides services to third-party customers, including major and independent producers. Anadarko generates revenues from its midstream activities through a variety of agreements including fixed-fee, percent-of-proceeds, and keep-whole agreements.

At the end of 2011, Anadarko had 31 gathering systems and 25 processing and treating plants located throughout major onshore producing basins in Wyoming, Colorado, Utah, New Mexico, Kansas, Oklahoma, Pennsylvania, and Texas. In 2011, the focus of the midstream activity was the Company's liquids-rich growth areas such as Greater Natural Buttes, Wattenberg, Delaware basin, and the Eagleford shale, as well as growth in the Marcellus shale dry-gas play. In 2012, the Company plans to continue to focus its midstream investments in these areas, as well as the prospective liquids-rich Utica shale play in Ohio.

In Greater Natural Buttes, gathering and compression capacity of 70 MMcf/d was added in 2011 and the Company is constructing a second cryogenic processing train with a capacity of 300 MMcf/d at the Chipeta processing complex. The new train is expected to commence operations by the third quarter of 2012.

In the Wattenberg area, the Company acquired an additional 93% interest in a 195 MMcf/d processing facility from a third party in May 2011 that positions the Company to realize the additional economics associated with the NGL uplift from its natural-gas production that was previously shared with the facility owner. The Company operates and owns a 100% interest in the Wattenberg Plant. The Company plans to expand cryogenic processing capacity with the addition of the 300 MMcf/d Lancaster plant in Wattenberg, which will significantly increase ethane recoveries in the basin. Permitting and engineering for the Lancaster Plant are underway with start-up operations planned for early 2014.

In the Delaware basin, the Company expanded its natural-gas-gathering capacity to 65 MMcf/d and placed oil-gathering and pipeline facilities into service. The oil-gathering and pipeline facilities are directly connected to third-party pipelines. This allows Anadarko to realize greater value for its oil production due to reduced trucking costs. Also in the Delaware basin, the Company entered into a joint venture with two third parties to build the 100 MMcf/d Ranch Westex joint-venture cryogenic processing plant that is expected to be operational in early 2013.

In the Eagleford shale, gas-gathering capacity was expanded from 100 MMcf/d in 2010 to 225 MMcf/d in 2011 with plans to further expand system capacity to 500 MMcf/d by the end of 2013. A new Company-operated cryogenic processing plant in the Eagleford shale with capacity of 200 MMcf/d is scheduled to be operational in the first quarter of 2013. The Eagleford oil-gathering system was placed in service in 2011 with an initial capacity of 30,000 Bbls/d. The Company plans to expand the capacity to 100,000 Bbls/d by the end of 2013. In addition, the first phase of a crude-oil pipeline, with an initial capacity of 100,000 Bbls/d, was placed in service. The oil pipeline replaces truck-based sales and provides price uplift on Anadarko's oil by reducing aggregate transportation costs.

In the Marcellus shale, Anadarko's gas-gathering capacity increased from 180 MMcf/d in 2010 to 500 MMcf/d in 2011. The Company plans to add an additional 500 MMcf/d of capacity in 2012.

During 2011, Anadarko and its partners agreed to design and construct a new NGL pipeline that will originate from Skellytown, Texas and extend approximately 580 miles to NGL fractionation and storage facilities in Mont Belvieu, Texas. The new Texas Express Pipeline (TEP) will help Anadarko maximize the value of the Company's production by providing additional takeaway capacity and enhancing access to the Gulf Coast NGL market. Initial capacity on TEP will be approximately 280,000 Bbls/d that can be readily expanded to approximately 400,000 Bbls/d. Subject to regulatory approvals, the pipeline is expected to begin service in the second quarter of 2013.

Western Gas Partners, LP (WES), a consolidated subsidiary of Anadarko, is a publicly traded limited partnership formed by Anadarko to own, operate, acquire, and develop midstream assets. In the first quarter of 2011, WES acquired a gas processing facility and related gathering systems in the Wattenberg area from a third party. At December 31, 2011, Anadarko held a 43.3% limited partner interest in WES, as well as the entire 2% general partner interest and incentive distribution rights.

The following table provides information regarding the Company's midstream assets by geographic regions.

Area	Asset Type	Miles of Gathering Pipelines	Total Horsepower	2011 Average Throughput (MMcf/d)
Rocky Mountains	Gathering, Processing, and Treating	9,700	1,088,200	3,500
Mid-Continent and other	Gathering	2,500	105,100	200
Texas	Gathering and Treating	2,200	168,700	700
Total		14,400	1,362,000	4,400

MARKETING ACTIVITIES

The Company's marketing segment actively manages Anadarko's natural-gas, crude-oil, condensate, and NGLs sales. In marketing its production, the Company attempts to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. The Company's sales of natural gas, crude oil, condensate, and NGLs are generally made at market prices for those products at the time of sale. The Company also purchases natural gas, crude oil, condensate, and NGLs from third parties, primarily near Anadarko's production areas, to aggregate volumes and better position the Company to fully utilize transportation and storage capacity, attract creditworthy customers, facilitate efforts to maximize prices received, and minimize balancing issues with customers and pipelines during operational disruptions.

The Company sells natural gas under a variety of contracts including indexed, fixed-price, and cost-escalation-based agreements. The Company also engages in limited trading activities for the purpose of generating profits from exposure to changes in market prices of natural gas, crude oil, condensate, and NGLs. The Company does not engage in market-making practices and limits its marketing activities to natural-gas, crude-oil, and NGLs commodity contracts. The Company's marketing risk position is typically a net short position (reflecting agreements to sell natural gas, crude oil, and NGLs in the future for specific prices) that is offset by the Company's natural long position as a producer (reflecting ownership of underlying natural-gas and crude-oil reserves). See *Energy Price Risk* under Item 7A of this Form 10-K.

Natural Gas Natural gas continues to fulfill a significant portion of North America's energy needs and the Company believes the importance of natural gas will continue to increase. Anadarko markets its natural-gas production to maximize its value and to reduce the inherent risks of physical commodity markets. Anadarko's marketing segment offers supply-assurance and limited risk-management services at competitive prices, as well as other services that are tailored to its customers' needs. The Company may also receive a service fee related to the level of reliability and service required by the customer.

The Company controls natural-gas firm transportation capacity that ensures access to downstream markets, which enables the Company to maximize its natural-gas production. This transportation capacity also provides the opportunity to capture incremental value when price differentials between physical locations exist. The Company also stores natural gas in contracted storage facilities to minimize operational disruptions to its ongoing operations and to take advantage of seasonal price differentials. Normally, the Company will have forward contracts in place (physical-delivery or financial derivative instruments) to sell stored natural gas at a fixed price.

Crude Oil, Condensate, and NGLs Anadarko's crude-oil, condensate, and NGLs revenues are derived from production in the United States, Algeria, China, and Ghana. Most of the Company's U.S. crude-oil and NGLs production is sold under contracts with prices based on market indices, adjusted for location, quality, and transportation. Oil from Algeria is sold by tanker as Saharan Blend to customers primarily in the Mediterranean area. Saharan Blend is high-quality crude that provides refiners large quantities of premium products such as gasoline, and jet and diesel fuel. Oil from China is sold by tanker as Cao Fei Dian (CFD) Blend to customers primarily in the Far East markets. CFD Blend is a heavy sour crude oil which is sold into both the prime fuels refining market and the market for the heavy fuel oil blend stock. Oil from Ghana is sold by tanker as Jubilee Crude Oil to customers around the world. Jubilee Crude Oil is high-quality crude that provides refiners large quantities of premium products such as gasoline and jet and diesel fuel. The Company also purchases and sells third-party-produced crude oil, condensate, and NGLs in the Company's domestic and international market areas, and utilizes contracted NGLs storage facilities to capture market opportunities and reduce fractionation and downstream infrastructure disruptions.

COMPETITION

The oil and gas business is highly competitive in the exploration for and acquisition of reserves and in the gathering and marketing of oil and gas production. The Company's competitors include national oil companies, major oil and gas companies, independent oil and gas companies, individual producers, gas marketers, and major pipeline companies, as well as participants in other industries supplying energy and fuel to consumers.

SEGMENT INFORMATION

For additional information on operations by segment, see *Note 20—Segment Information* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

For additional information on risk associated with international operations, see *Risk Factors* under Item 1A of this Form 10-K.

EMPLOYEES

The Company had approximately 4,800 employees at December 31, 2011.

REGULATORY MATTERS, ENVIRONMENTAL, AND ADDITIONAL FACTORS AFFECTING BUSINESS

Environmental and Occupational Health and Safety Regulations

Anadarko's business operations are subject to numerous international, federal, state and local environmental and occupational health and safety laws and regulations pertaining to the release, emission, or discharge of materials into the environment; the generation, storage, transportation, handling, and disposal of materials (including solid and hazardous wastes); the workplace health and safety of employees; or otherwise relating to the prevention, mitigation, or remediation of pollution, or the preservation or protection of natural resources, wildlife, or the environment. The more significant of these existing environmental and occupational health and safety laws and regulations include the following U.S. laws and regulations, as amended from time to time:

- The U.S. Clean Air Act, which restricts the emission of air pollutants from many sources and imposes various pre-construction, monitoring, and reporting requirements.
- The U.S. Federal Water Pollution Control Act, also known as the federal Clean Water Act (CWA), which regulates discharges of pollutants from facilities to state and federal waters.
- The U.S. Oil Pollution Act of 1990 (OPA), which subjects owners and operators of vessels, onshore facilities, and pipelines, as well as lessees or permittees of areas in which offshore facilities are located, to strict liability for removal costs and damages arising from an oil spill in waters of the United States.
- U.S. Department of the Interior (DOI) regulations, which relate to offshore oil and natural-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.
- The Comprehensive Environmental Response, Compensation and Liability Act of 1980, a remedial statute that imposes strict liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur.
- The U.S. Resource Conservation and Recovery Act, which governs the treatment, storage, and disposal of solid wastes, including hazardous wastes.
- The U.S. Federal Safe Drinking Water Act, which ensures the quality of the nation's public drinking water through adoption of drinking water standards and controlling the injection of waste fluids into below-ground formations that may adversely affect drinking water sources.
- The U.S. Emergency Planning and Community Right-to-Know Act, which requires facilities to disseminate information on chemical inventories to employees as well as local emergency planning committees and response departments.
- The U.S. Occupational Safety and Health Act, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures.
- The National Environmental Policy Act, which requires federal agencies, including the DOI, to evaluate major agency actions having the potential to significantly impact the environment and which may require the preparation of Environmental Assessments and more detailed Environmental Impact Statements that may be made available for public review and comment.
- The Endangered Species Act, which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas.

- The Marine Mammal Protection Act, which ensures the protection of marine mammals through the prohibition, with certain exceptions, of the taking of marine mammals in U.S. waters and by U.S. citizens on the high seas and which may require the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas.
- The Migratory Bird Treaty Act, which implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds and, pursuant to which the taking, killing or possessing of migratory birds is unlawful without a permit, thereby potentially requiring the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas.

These laws and their implementing regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and ground water. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the development of projects; and the issuance of injunctions restricting or prohibiting some or all of the Company's activities in a particular area. Compliance with these laws and regulations also, in most cases, requires new or amended permits that may contain new or more stringent technological standards or limits on emissions, discharges, disposals, or other releases in association with new or modified operations. Application for 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 public notice and comment periods required prior to the issuance or amendment of a permit as well as the agency's processing of an application. Many of the delays associated with the permitting process are beyond the control of the Company.

Many states and foreign countries where the Company operates also have, or are developing, similar environmental laws, regulations, or analogous controls governing many of these same types of activities. While the legal requirements may be similar in form, in some cases the actual implementation of these requirements may impose additional, or more stringent, conditions or controls that can significantly alter or delay the development of a project or substantially increase the cost of doing business.

Anadarko is also subject to certain laws and regulations relating to environmental remediation obligations associated with current and past operations.

Federal and state occupational safety and health laws require the Company to organize information about materials, some of which may be hazardous or toxic, that are used, released or produced in Anadarko's operations. Certain portions of this information must be provided to employees, state and local governmental authorities and responders, and local citizens. The Company is also subject to the safety hazard communication requirements and reporting obligations set forth in federal workplace standards.

There have been several regulatory and governmental initiatives to restrict the hydraulic-fracturing process, which could have an adverse impact on our completion or production activities. The U.S. Environmental Protection Agency (EPA) has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic-fracturing practices notwithstanding the existence of current oil and gas regulations adopted at the state level. Moreover, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with final results expected to be available by 2014. The EPA has also announced plans to propose effluent limitations for the treatment and discharge of wastewater resulting from hydraulic-fracturing activities by 2014. Certain other governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices, including evaluations by the U.S. Department of Energy and the DOI, and coordination of an administration-wide review of these practices by the White House Council on Environmental Quality. Congress is currently considering, and has from time to time in the past considered, bills that would regulate hydraulic fracturing and/or require public disclosure of chemicals used in the hydraulic-fracturing process. A number of states, including states in which we operate, have adopted or are considering legal requirements that could impose more stringent permitting, public disclosure, and well-construction requirements on hydraulic-fracturing activities.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as new standards, such as air emission standards and water quality standards, continue to evolve. However, environmental laws and regulations, including those that may arise to address concerns about global climate change and the threat of adverse impacts to groundwater arising from hydraulic-fracturing activities, are expected to continue to have an increasing impact on the Company's operations in the United States and in other countries in which Anadarko operates. Notable areas of potential impacts include air emission monitoring, compliance, mitigation, and remediation obligations in the United States.

The Company has reviewed its potential responsibilities under both OPA and CWA as they relate to the Deepwater Horizon events. OPA imposes joint and several liability on the responsible parties for all cleanup and response costs, natural resource damages, and other damages such as lost revenues, damages to real or personal property, damages to subsistence users of natural resources, and lost profits and earning capacity. While OPA requires that a responsible party pay for all cleanup and response costs, it currently limits liability for damages to $75 million, exclusive of response and remediation expenses (for which there is no cap), except in cases of gross negligence, willful misconduct, or the violation of an applicable federal safety, construction, or operating regulation. The federal government may take legislative or other action to increase or eliminate, perhaps even retroactively, the liability cap. As for damages to natural resources, the government may recover damages for injury to, loss of, destruction of, or loss of use of natural resources which may include the costs to repair, replace, or restore those or like resources. The CWA governs discharges into waters of the United States and provides for penalties in the event of unauthorized discharges into those waters. Under the CWA, these include, among other penalties, civil penalties that may be assessed in an amount up to $1,100 per barrel of oil discharged. In cases of gross negligence or willful misconduct, such civil penalties that may be sought by the EPA are increased to not more than $4,300 per barrel of oil discharged.

As of the date of filing this Form 10-K with the SEC, no penalties or fines have been assessed by the federal government against the Company under OPA, CWA, and other similar local, state and federal environmental legislation related to the Deepwater Horizon events. However, in December 2010, the Department of Justice (DOJ), on behalf of the federal agencies involved in the spill response, filed a civil lawsuit in the U.S. District Court for the Eastern District of Louisiana against several parties, including the Company, seeking (i) an assessment of civil penalties under the CWA in an amount to be determined by the court, and (ii) a declaratory judgment that such parties are jointly and severally liable without limitation under OPA for all removal costs and damages resulting from the Deepwater Horizon events. In October 2011, the Company and BP entered into a settlement agreement, mutual releases, and agreement to indemnify, relating to the Deepwater Horizon events (Settlement Agreement), pursuant to which BP has fully indemnified Anadarko against all claims, causes of action, losses, costs, expenses, liabilities, damages, or judgments of any kind arising out of the Deepwater Horizon events and related damage claims arising under OPA. Under the Settlement Agreement, BP does not indemnify the Company against penalties or fines that may be assessed against the Company as a result of the Deepwater Horizon events, including for example, under the CWA. For additional information, see *Note 2—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

The Company has made and will continue to make operating and capital expenditures, some of which may be material, to comply with environmental and occupational health and safety laws and regulations. These are necessary business costs in the Company's operations and in the oil and natural-gas industry. Although the Company is not fully insured against all environmental and occupational health and safety risks, and the Company's insurance does not cover any penalties or fines that may be issued by a governmental authority, it maintains insurance coverage that it believes is sufficient based on the Company's assessment of insurable risks and consistent with insurance coverage held by other similarly situated industry participants. Nevertheless, it is possible that other developments, such as stricter and more comprehensive environmental and occupational health and safety laws and regulations, as well as claims for damages to property or persons resulting from the Company's operations, could result in substantial costs and liabilities, including administrative, civil, and criminal penalties, to Anadarko. The Company believes that it is in material compliance with existing environmental and occupational health and safety regulations. Further, the Company believes that the cost of maintaining compliance with these existing laws and regulations will not have a material adverse effect on its business, financial position, results of operations, or cash flows, but new or more stringently applied or enforced existing laws and regulations could increase the cost of doing business, and such increases could be material.

Oil Spill-Response Plan

Domestically, the Company is required to comply with BSEE regulations, which require every owner or operator of a U.S. offshore lease to prepare and submit for approval an oil spill-response plan prior to conducting any offshore operations. The submitted plan is required to provide a detailed description of actions to be taken in the event of a spill, identify contracted spill-response equipment, materials and trained personnel, and stipulate the time necessary to deploy identified resources in the event of a spill. The Company has filed the information that describes the Company's ability to deploy surface and subsea containment resources to adequately and promptly respond to a blowout or other loss of well control. The BSEE regulations may be amended, resulting in changes to the amount and type of spill-response resources to which an owner or operator must maintain ready access. Accordingly, resources available to the Company may change in order to satisfy any new regulatory requirements, or to adapt to changes in the Company's operations.

Anadarko has in place and maintains both Regional (Central and Western Gulf of Mexico) and Sub-Regional (Eastern Gulf of Mexico) Oil Spill-Response Plans (Plans) for the Company's Gulf of Mexico operations. These plans detail procedures for a rapid and effective response to spill events that may occur as a result of Anadarko's operations. The Plans are reviewed at least annually and updated as necessary. Drills are conducted at least annually to test the effectiveness of the Plans and include the participation of spill-response contractors, representatives of Clean Gulf Associates (CGA, a not-for-profit association of production and pipeline companies operating in the Gulf of Mexico), and representatives of relevant governmental agencies. The Plans must be approved by the BSEE.

As part of the Company's oil spill-response preparedness, and as set forth in the Plans, Anadarko maintains membership in CGA, and has an employee representative on the executive committee of CGA. CGA was created to provide a means of effectively staging response equipment and to provide effective spill-response capability for its member companies operating in the Gulf of Mexico.

CGA equipment includes one High Volume Open Sea Skimmer System (HOSS) barge, four 46-foot skimming vessels, one 56-foot skimming vessel, three Marco skimmers, and two Egmopol skimmers. In addition, CGA equipment also consists of:

- Nine Fast Response Units;
- One rope mop;
- Three Foilex skim packages;
- Two 4-drum skimmers (Magnum 100);
- Two 2-drum skimmers (TDS 118);
- Eleven sets of Koseq skimming arms;
- Two Aqua Guard Triton RBS;
- Four oil storage barges (249 barrels);
- Ten tanks (100 barrels, primary); and
- Nine tanks (100 barrels, secondary).

Auto boom, beach boom, and fire boom are currently available through CGA. CGA also has a stockpile of Corexit 9500 dispersant spray system through Airborne Support Inc. (ASI), a wildlife rehabilitation trailer, and bird scare guns. CGA currently has one X-band radar installed on the HOSS Barge. CGA has ordered three 95–foot fast response vessels and is scheduled to receive delivery on or about the end of the second quarter of 2012.

The CGA coordinates bareboat charters with Marine Spill Response Corporation (MSRC). MSRC is responsible for inspecting, maintaining, storing, and calling out CGA equipment. MSRC has positioned CGA's equipment and materials in a ready state at various staging areas around the Gulf of Mexico.

MSRC also handles the maintenance and mobilization of CGA non-marine equipment. MSRC has service contracts in place with domestic environmental contractors as well as with other companies that provide support services during the execution of spill-response activities. In the event of a spill, MSRC will activate these contracts as necessary to provide additional resources or support services requested by CGA. In addition, CGA maintains a service contract with ASI, which provides aircraft and dispersant capabilities for CGA member companies.

As of December 2, 2011, Anadarko became a member of the Marine Preservation Association, which provides full access to the MSRC cooperative including the Deep Blue enhanced Gulf of Mexico Response capability. In the event of a spill, MSRC stands ready to mobilize all of its equipment and materials, including those from CGA. MSRC has a fleet of 15 dedicated Responder Class Oil Spill-Response Vessels (OSRVs), designed and built specifically to recover spilled oil. Each OSRV is approximately 210 feet long, has temporary storage for recovered oil, and has the ability to separate oil and water aboard the vessels using two oil-water separation systems. To enable the OSRV to sustain cleanup operations, recovered oil is transferred into other vessels or barges.

MSRC has equipment housed for the Atlantic Region, the Gulf of Mexico Region, the California Region, and the Pacific Northwest Region. The Gulf of Mexico Region has a total of 61 skimmers with an Effective Daily Recovery Capacity of 449,108 barrels. The following equipment was available through the various regions at December 31, 2011:

- Fifteen Responder Class OSRVs;
- Twenty-nine smaller OSRVs;
- Five Fast Response Vessels;
- Nineteen offshore barges;
- Fifty-one shallow water barges (non self-propelled);
- Fifty-one shallow water push boats;
- Seventeen shallow water barges (self-propelled);
- Seventy-one towable storage bladders;
- Three towable storage barges (non self-propelled);
- Twenty-one work boats;
- Twenty-three fastanks (900 barrels);
- Six mini towable storage bladders;
- Twelve tanks/seabags;
- Seven small skimming vessels;
- Nine small barges;
- Thirteen small boats;
- One small Oil Spill-Response Barge;
- Fifteen storage tanks/bladders;
- 275,734 feet of ocean boom;
- 103,159 gallons of Corexit 9500 dispersant; and
- 1,500 gallons of Corexit 9527 dispersant.

As of December 31, 2011, Anadarko will no longer maintain a retainer-based service contract with National Response Corporation. These services have been superseded by the MSRC contract and are available as a commercial service should the extraordinary case arise.

Anadarko has emergency and oil spill-response plans in place for each of its exploration and operational activities around the globe. Each plan satisfies the requirements of the relevant local or national authority, describes the actions the Company will take in the event of an incident, is subject to drills at least annually, and includes reference to external resources that may become necessary in the event of an incident. Included in these external resources is the Company's contract with Oil Spill Response Limited (OSR), a global emergency and oil spill-response organization headquartered in London. OSR maintains specialized equipment in a ready state for deployment in the event such equipment is needed by one of its members. OSR is mainly available for response internationally, but its equipment is registered with the U.S. Coast Guard for domestic use if needed.

OSR has two Hercules aircraft, located in the United Kingdom and Singapore, available for dispersant application or equipment transport. The aircraft have a three-hour callback time. The Hercules can transport two to three pre-packaged equipment loads, or one Aerial Dispersant Delivery System (ADDS) Pack. OSR has 3 ADDS Packs; one in the United Kingdom, one in Bahrain, and one in Singapore. If additional aircraft are needed, OSR retains an aircraft broker so that an aircraft can be chartered. For international operations, the majority of equipment will be air freighted. Fast response trailers are available, if within the United Kingdom.

OSR has a number of active recovery boom systems, and a range of booms that can be used for offshore, nearshore, or shoreline responses. Offshore boom is stored in the United Kingdom, Bahrain, and Singapore. Fireboom systems have been delivered and a team is trained to operate the system. A variety of nearshore boom exists for spill containment.

Additionally OSR can provide a range of communications equipment, safety equipment, transfer pumps, dispersant application systems, temporary storage equipment, power packs and generators, small inflatable vessels, rigid inflatable boats, work boats, and Fast Response Vessels. Oleophilic, weir, and mechanical skimmers provide the ability to recover a range of oil types. OSR also has a wide range of oiled wildlife equipment in conjunction with the Sea Alarm Foundation.

The Company has also entered into contractual commitments to access subsea intervention, containment, capture, and shut-in capacity (Containment) for deepwater exploration wells. CGA has contracted with Helix Energy Solutions Group (Helix), on behalf of its membership, for the provision of these Containment assets, which will initially provide processing capacity of 45,000 Bbls/d of oil, 60,000 Bbls/d of liquids, and flaring of 80 MMcf/d of natural gas from the vessel HP-1, and burning 10,000 Bbls/d of oil from the vessel Q4000. The system, known as the Helix Fast Response System, currently operates at up to 8,000 feet of sea water depth, and is rated at a 10,000 psi shut-in capability. Member operators are considering various capacity expansion options.

In addition, during 2011, the Company became an investing member in the Marine Well Containment Company (MWCC), which is open to all oil and gas operators in the U.S. Gulf of Mexico and provides members access to oil spill-response equipment and services on a per-well fee basis. Anadarko has an employee representative on the Executive Committee of MWCC and this employee currently serves as its Chair. MWCC members have access to an interim containment system that includes a 15-kpsi capping stack and dispersant capability. The interim containment system is engineered to operate in deepwater depths of up to 10,000 feet, and has the capacity to contain 60 MBbls/d of liquids and flare 120 MMcf/d of natural gas. The DOI has reviewed the functional specifications of the MWCC interim containment system, and DOI input was included in the final specifications.

MWCC members also expect to have access to an expanded containment system that is planned for use in deepwater depths of up to 10,000 feet with containment capacity of 100 MBbls/d of liquids and flare capability for 200 MMcf/d of natural gas. The expanded system is planned to include a 15-kpsi subsea containment assembly with three rams stack, dedicated capture vessels, and a dispersant injection system. The expanded containment system may also be further expanded with additional capture vessels, modified tankers, drill ships, and extended well-test vessels, all of which may process, store, and offload oil to shuttle tankers, which may then take the oil to shore for further processing. This expanded containment system is on schedule for delivery in 2012.

In addition to Anadarko's membership in or access to CGA, MSRC, OSR, Helix, and MWCC, the Company is also participating in industry-wide task forces, which are currently studying improvements in both gaining access to and controlling blowouts in subsea environments. Two such task forces are the Subsea Well Control and Containment Task Force, and the Oil Spill Task Force.

TITLE TO PROPERTIES

As is customary in the oil and gas industry, only a preliminary title review is conducted at the time properties believed to be suitable for drilling operations are acquired by the Company. Prior to the commencement of drilling operations, a thorough title examination of the drill site tract is conducted and curative work is performed with respect to significant defects, if any, before proceeding with operations. Anadarko believes the title to its leasehold properties is good, defensible, and customary with practices in the oil and gas industry, subject to such exceptions that, in the opinion of legal counsel for the Company, do not materially detract from the use of such properties.

Leasehold properties owned by the Company are subject to royalty, overriding royalty, and other outstanding interests customary in the industry. The properties may be subject to burdens such as liens incident to operating agreements, current taxes, development obligations under oil and gas leases and other encumbrances, easements, and restrictions. Anadarko does not believe any of these burdens will materially interfere with its use of these properties.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Age as of February 21, 2012	Position
James T. Hackett	58	Chairman of the Board and Chief Executive Officer
R. A. Walker	55	President and Chief Operating Officer
Robert P. Daniels	53	Senior Vice President, Worldwide Exploration
Robert G. Gwin	48	Senior Vice President, Finance and Chief Financial Officer
Charles A. Meloy	51	Senior Vice President, Worldwide Operations
Robert K. Reeves	54	Senior Vice President, General Counsel and Chief Administrative Officer
M. Cathy Douglas	55	Vice President and Chief Accounting Officer

On February 21, 2012, Anadarko announced the transition of Mr. Hackett from Chairman and Chief Executive Officer to Executive Chairman effective May 15, 2012. Mr. Hackett was named Chief Executive Officer in December 2003 and assumed the additional role of Chairman of the Board in January 2006. He also served as President from December 2003 to February 2010. Prior to joining Anadarko, Mr. Hackett served as President and Chief Operating Officer of Devon Energy Corporation following its merger with Ocean Energy, Inc. in April 2003. He served as President and Chief Executive Officer of Ocean Energy, Inc. from March 1999 to April 2003 and as Chairman of the Board from January 2000 to April 2003. He currently serves as a director of Fluor Corporation, Bunge Limited, and The Welch Foundation.

On February 21, 2012, Anadarko announced the appointment of Mr. Walker as Chief Executive Officer of Anadarko effective May 15, 2012. He will continue as President. Mr. Walker was named Chief Operating Officer in March 2009 and assumed the additional role of President in February 2010. He previously served as Senior Vice President, Finance and Chief Financial Officer from September 2005 until his appointment as Chief Operating Officer. Prior to joining Anadarko, Mr. Walker served as Managing Director for the Global Energy Group of UBS Investment Bank from 2003 to 2005. Mr. Walker served as a director of Temple-Inland Inc. from November 2008 to February 2012 and has served as a director of CenterPoint Energy, Inc. since April 2010. Since August 2007, he has also served as director of Western Gas Holdings, LLC, the general partner of WES, and served as the general partner's Chairman of the Board from August 2007 to September 2009.

Mr. Daniels was named Senior Vice President, Worldwide Exploration in December 2006. Prior to this position, he served as Senior Vice President, Exploration and Production since May 2004 and prior to that position, he served as Vice President, Canada since July 2001. Mr. Daniels also served in various managerial roles in the Exploration Department for Anadarko Algeria Company, LLC. He has worked for the Company since 1985.

Mr. Gwin was named Senior Vice President, Finance and Chief Financial Officer in March 2009 and previously had served as Senior Vice President since March 2008. He also serves as Chairman of the Board of Western Gas Holdings, LLC, the general partner of WES, since October 2009 and as a director since August 2007. Mr. Gwin also served as President of Western Gas Holdings, LLC from August 2007 to September 2009 and as Chief Executive Officer of Western Gas Holdings, LLC from August 2007 to January 2010. He joined Anadarko in January 2006 as Vice President, Finance and Treasurer and served in that capacity until March 2008. Prior to joining Anadarko, he served as President and CEO of Prosoft Learning Corporation from November 2002 to November 2004 and as Chairman from November 2002 to February 2006. Previously, Mr. Gwin spent 10 years at Prudential Capital Group in merchant banking roles of increasing responsibility, including serving as Managing Director with responsibility for the firm's energy investments worldwide. He has served as a director of LyondellBassell Industries N.V. since May 2010.

Mr. Meloy was named Senior Vice President, Worldwide Operations in December 2006 and served as Senior Vice President, Gulf of Mexico and International Operations since the acquisition of Kerr-McGee in August 2006. Prior to joining Anadarko, he served Kerr-McGee as Vice President of Exploration and Production from 2005 to 2006, Vice President of Gulf of Mexico Exploration, Production and Development from 2004 to 2005, Vice President and Managing Director of Kerr-McGee North Sea (U.K.) Limited from 2002 to 2004 and Vice President of Gulf of Mexico Deep Water from 2000 to 2002. Mr. Meloy has served as a director of Western Gas Holdings, LLC since February 2009.

Mr. Reeves was named Senior Vice President, General Counsel and Chief Administrative Officer in February 2007 and served as Corporate Secretary from February 2007 to August 2008. He previously served as Senior Vice President, Corporate Affairs & Law and Chief Governance Officer since 2004. Prior to joining Anadarko, he served as Executive Vice President, Administration and General Counsel of North Sea New Ventures from 2003 to 2004, and as Executive Vice President, General Counsel and Secretary of Ocean Energy, Inc. and its predecessor companies from 1997 to 2003. He has served as a director of Key Energy Services, Inc., a publicly traded oilfield services company, since October 2007, and as a director of Western Gas Holdings, LLC since August 2007.

Ms. Douglas was named Vice President and Chief Accounting Officer in November 2008 and served as Corporate Controller from September 2007 to March 2009. She served as Assistant Controller from July 2006 to September 2007. She also served as Director, Accounting, Policy and Coordination from October 2006 to September 2007 and Financial Reporting and Policy Manager from January 2003 to October 2006. Ms. Douglas joined Anadarko in 1979.

Officers of Anadarko are elected at an organizational meeting of the Board of Directors following the annual meeting of stockholders, which is expected to occur on May 15, 2012, and hold office until their successors are duly elected and shall have qualified. There are no family relationships between any directors or executive officers of Anadarko.

Item 1A. Risk Factors

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

The Company has made in this report, and may from time to time otherwise make in other public filings, press releases, and management discussions, 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 concerning the Company's operations, economic performance, and financial condition. These forward-looking statements include information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and gas properties, marketing and midstream activities, and also include those statements preceded by, followed by, or that otherwise include the words "may," "could," "believes," "expects," "anticipates," "intends," "estimates," "projects," "target," "goal," "plans," "objective," "should," or similar expressions or variations on such expressions. For such statements, the Company claims the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to be correct. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events, or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from the Company's expectations include, but are not limited to, the following risks and uncertainties:

- *the Company's assumptions about the energy market;*
- *production levels;*
- *reserve levels;*
- *operating results;*
- *competitive conditions;*
- *technology;*
- *the availability of capital resources, capital expenditures, and other contractual obligations;*
- *the supply and demand for, the price of, and the commercializing and transporting of natural gas, crude oil, natural gas liquids (NGLs), and other products or services;*
- *volatility in the commodity-futures market;*
- *the weather;*
- *inflation;*
- *the availability of goods and services;*
- *drilling risks;*
- *future processing volumes and pipeline throughput;*
- *general economic conditions, either internationally or nationally or in the jurisdictions in which the Company or its subsidiaries are doing business;*
- *legislative or regulatory changes, including retroactive royalty or production tax regimes; hydraulic-fracturing regulation; deepwater drilling and permitting regulations; derivatives reform; changes in state, federal, and foreign income taxes; environmental regulation; environmental risks; and liability under federal, state, foreign, and local environmental laws and regulations;*
- *the ability of BP Exploration & Production Inc. (BP) to meet its indemnification obligations to the Company for, among other things, damage claims arising under the Oil Pollution Act of 1990 (OPA), claims for natural resource damages (NRD) and associated damage-assessment costs, and any claims arising under the Operating Agreement (OA) for the Macondo well, as well as the ability of BP*

Corporation North America Inc. (BPCNA) and BP p.l.c. to satisfy their guarantees of such indemnification obligations;

- *the impact of remaining claims related to the Deepwater Horizon events, including, but not limited to, fines, penalties, and punitive damages for which the Company is not indemnified by BP;*
- *the legislative and regulatory changes that may impact the Company's Gulf of Mexico and international offshore operations;*
- *the impact of future regulations on the Company's ability to fully resume drilling operations in the Gulf of Mexico;*
- *current and potential legal proceedings, environmental or other obligations related to or arising from Tronox Incorporated (Tronox);*
- *civil or political unrest in a region or country;*
- *the creditworthiness and performance of the Company's counterparties, including financial institutions, operating partners, and other parties;*
- *volatility in the securities, capital, or credit markets;*
- *the Company's ability to successfully monetize select assets, repay its debt, and the impact of changes in the Company's credit ratings;*
- *disruptions in international crude oil cargo shipping activities;*
- *electronic, cyber, and physical security breaches;*
- *the supply and demand, technological, political, and commercial conditions associated with long-term development and production projects in domestic and international locations;*
- *the outcome of proceedings related to the Algerian exceptional profits tax; and*
- *other factors discussed below and elsewhere in this Form 10-K, and in the Company's other public filings, press releases, and discussions with Company management.*

We may be subject to claims and liabilities relating to the Deepwater Horizon events that are not covered by BP's indemnification obligations under our Settlement Agreement with BP, or that result in losses to the Company, notwithstanding BP's indemnification against such losses, as a result of BP's inability to satisfy its indemnification obligations under the Settlement Agreement and BPCNA's and BP p.l.c's inability to satisfy their guarantees of BP's indemnification obligations.

In October 2011, the Company and BP entered into a settlement agreement, mutual releases, and agreement to indemnify, relating to the Deepwater Horizon events (Settlement Agreement). Pursuant to the Settlement Agreement, the Company paid $4.0 billion and transferred its interest in the Macondo well and the Lease to BP, and BP accepted this consideration in full satisfaction of its claims against Anadarko for $6.1 billion of invoices issued through the settlement date as well as for potential reimbursements of subsequent costs incurred by BP related to the Deepwater Horizon events, including costs under the OA.

Under the Settlement Agreement, BP fully indemnified Anadarko against all claims, causes of action, losses, costs, expenses, liabilities, damages, or judgments of any kind arising out of the Deepwater Horizon events, related damage claims arising under OPA, NRD claims and associated damage-assessment costs, and any claims arising under the OA. This indemnification is guaranteed by BPCNA and, in the event that the net worth of BPCNA declines below an agreed-upon amount, BP p.l.c. has agreed to become the sole guarantor.

Any failure or inability on the part of BP to satisfy its indemnification obligations under the Settlement Agreement, or on the part of BPCNA or BP p.l.c. to satisfy their respective guarantee obligations, could subject us to significant monetary liability beyond the terms of the Settlement Agreement, which could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity. Furthermore, in certain instances we may be required to recognize a liability for amounts for which we are indemnified in advance of or in connection with recognizing a receivable from BP for the related indemnity payment. Any such liability recognition without collection of the offsetting receivable could adversely impact our results of operations, our financial condition, and our ability to make borrowings.

Under the Settlement Agreement, BP does not indemnify the Company against fines and penalties, punitive damages, shareholder, derivative, or security laws claims, or certain other claims. The adverse resolution of any current or future proceeding related to the Deepwater Horizon events for which we are not indemnified by BP could subject us to significant monetary liability, which could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

The additional deepwater drilling laws and regulations, delays in the processing and approval of drilling permits and exploration and oil spill-response plans, and other related developments arising after the deepwater drilling moratorium in the Gulf of Mexico may have a material adverse effect on our business, financial condition, or results of operations.

In May and July 2010, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), previously known as the Minerals Management Service, an agency of the Department of the Interior (DOI), issued directives requiring lessees and operators of federal oil and gas leases in the Outer Continental Shelf (OCS) regions of the Gulf of Mexico and Pacific Ocean to cease drilling all new deepwater wells, including wellbore sidetracks and bypasses, but excluding workovers, completions, plugging and abandonment, or production, through November 30, 2010 (Moratorium). Anadarko ceased all drilling operations in the Gulf of Mexico in accordance with the Moratorium, which resulted in the suspension of operations of two operated deepwater wells (Lucius and Nansen) and one non-operated deepwater well (Vito). The Moratorium was lifted effective October 12, 2010.

Between mid-May 2010 and mid-October 2010, part of which time the Moratorium was in place, the BOEMRE issued a series of rules and Notices to Lessees and Operators (NTLs) imposing new regulatory safety and performance requirements and permitting procedures for new wells to be drilled in federal waters of the OCS. The new regulatory requirements include the following:

- Environmental NTL, which imposes new and more stringent requirements for documenting the environmental impacts potentially associated with the drilling of a new offshore well and significantly increases oil spill response requirements.
- Compliance and Review NTL, which imposes requirements for operators to secure independent reviews of well design, construction and flow intervention processes, and also requires certifications of compliance from senior corporate officers.
- Drilling Safety Rule, which prescribes tighter cementing and casing practices, imposes standards for the use of drilling fluids to maintain well bore integrity, and enhances oversight requirements relating to blowout preventers and related components, including shear and pipe rams.
- Workplace Safety Rule, which requires operators to have a comprehensive safety and environmental management system (SEMS) in order to reduce human and organizational errors as root causes of work-related accidents and offshore spills. The BOEMRE subsequently issued a proposed rulemaking in 2011 that would amend the Workplace Safety Rule by requiring the imposition of certain added safety procedures to a company's SEMS not covered by the original rule (including, by way of example, procedures to authorize any and all employees on an offshore facility authority to stop work when witnessing any activity that poses a threat of danger to an individual, property, or the environment) and revising existing obligations that a company's SEMS be audited by requiring the use of an independent third-party auditor who is pre-approved by the agency to perform the auditing task.

In addition, the BOEMRE issued an NTL effective October 15, 2010, that established a more stringent regiment for the timely decommissioning of what is known as "idle iron"—wells, platforms, and pipelines that are no longer producing or serving exploration or support functions related to an operator's lease—in the Gulf of Mexico. This NTL establishes more stringent standards for the deadlines by which idle iron must be decommissioned, the result of which is that Anadarko anticipates incurring costs to plug, abandon, or decommission wells and facilities on a more expedited basis than it might otherwise, absent this NTL.

The federal government may issue further safety and environmental laws and regulations regarding operations in the Gulf of Mexico. These additional rules and regulations, delays in the processing and approval of drilling permits and exploration, development, and oil spill-response plans, as a result of the new laws and regulations, the split of the BOEMRE into two new federal bureaus, and possible additional regulatory initiatives could adversely affect and further delay new drilling and ongoing development efforts in the Gulf of Mexico. Among other adverse impacts, these additional measures could delay or disrupt our operations, result in increased costs and limit activities in certain areas of the Gulf of Mexico. We cannot predict with any certainty the full impact of any new laws or regulations on our drilling operations in the Gulf of Mexico.

In addition to the drilling restrictions and new safety and permitting measures already issued and the possibility of new safety and environmental laws and regulations in the future, there have been discussions by government and private constituencies to amend existing laws such that exploration and production operators in the Gulf of Mexico would have to demonstrate or otherwise have available greater financial resources in order to conduct operations. For example, legislation has been discussed that could require companies operating in the Gulf of Mexico to establish and maintain a higher level of financial responsibility under its Certificate of Financial Responsibility, a certificate required by the OPA which evidences a company's financial ability to pay for cleanup and damages caused by oil spills. There have also been discussions regarding the establishment of a new industry mutual insurance fund in which companies would be required to participate and which would be available to pay for consequential damages arising from an oil spill.

Other governments may also adopt safety, environmental or other laws and regulations that would adversely impact our offshore developments in other areas of the world, including offshore Brazil, New Zealand, West Africa, Mozambique, and Southeast Asia. Additional U.S. or foreign government laws or regulations would likely increase the costs associated with the offshore operations of our drilling contractors. As a result, our drilling contractors may seek to pass increased operating costs to us through higher day-rate charges or through cost escalation provisions in existing contracts.

In addition to increased governmental regulation, insurance costs may increase across the energy industry and certain insurance coverage may be subject to reduced availability or not available on economically reasonable terms, if at all. In particular, the events in the Gulf of Mexico relating to the Macondo well may make it increasingly difficult to obtain offshore property damage, well control, and similar insurance coverage. The potential increased costs and risks associated with offshore development may also result in certain current participants allocating resources away from offshore development and discourage potential new participants from undertaking offshore development activities. Accordingly, we may encounter increased difficulty identifying suitable partners willing to participate in our offshore drilling projects and prospects.

Further, the deepwater Gulf of Mexico (as well as international deepwater locations) lacks the degree of physical and oilfield service infrastructure present in shallower waters. Therefore, it may be difficult for us to quickly or effectively execute any contingency plans related to future events similar to the Macondo well oil spill.

The matters described above, individually or in the aggregate, could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

We are, and in the future may become, involved in legal proceedings related to Tronox and, as a result, may incur substantial costs in connection with those proceedings.

In January 2009, Tronox Incorporated (Tronox), a former subsidiary of Kerr-McGee Corporation (Kerr-McGee), which is a current subsidiary of Anadarko, and certain of Tronox's subsidiaries filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code (the Bankruptcy) in the U.S. Bankruptcy Court for the Southern District of New York (Bankruptcy Court). Subsequently, in May 2009, Tronox and certain of its affiliates filed a lawsuit against Anadarko and Kerr-McGee asserting a number of claims, including claims for actual and constructive fraudulent conveyance (Adversary Proceeding). Tronox alleges, among other things, that it was insolvent or undercapitalized at the time it was spun off from Kerr-McGee and seeks, among other things, to recover damages, including interest, in excess of $14.5 billion from Kerr-McGee and Anadarko, as well as litigation fees and costs. An adverse resolution of any proceedings related to Tronox could subject us to significant monetary damages and other penalties, which could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

For additional information regarding the nature and status of these and other material legal proceedings, see *Note 16—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Oil, natural-gas, and NGLs prices are volatile. A substantial or extended decline in the price of these commodities could adversely affect our financial condition and results of operations.

Prices for oil, natural gas, and NGLs can fluctuate widely. Our revenues, operating results, and future growth rates are highly dependent on the prices we receive for our oil, natural gas, and NGLs. Historically, the markets for oil, natural gas, and NGLs have been volatile and may continue to be volatile in the future. For example, market prices for natural gas in the United States have declined substantially from 2008 price levels, and the rapid development of shale plays throughout North America has contributed significantly to this trend. Factors influencing the prices of oil, natural gas, and NGLs are beyond our control. These factors include, but are not limited to, the following:

- domestic and worldwide supply of, and demand for, oil, natural gas, and NGLs;
- volatile trading patterns in the commodity-futures markets;
- the cost of exploring for, developing, producing, transporting, and marketing oil, natural gas, and NGLs;
- weather conditions;
- the ability of the members of the Organization of Petroleum Exporting Countries (OPEC) and other producing nations to agree to and maintain production levels;
- the worldwide military and political environment, civil and political unrest in Africa and the Middle East, uncertainty or instability resulting from the escalation or additional outbreak of armed hostilities, or further acts of terrorism in the United States, or elsewhere;
- the effect of worldwide energy conservation and environmental protection efforts;
- the price and availability of alternative and competing fuels;
- the price and level of foreign imports of oil, natural gas, and NGLs;
- domestic and foreign governmental regulations and taxes;
- the proximity to, and capacity of, natural-gas pipelines and other transportation facilities; and
- general economic conditions worldwide.

The long-term effect of these and other factors on the prices of oil, natural gas, and NGLs are uncertain. Prolonged or substantial declines in these commodity prices may have the following effects on our business:

- adversely affecting our financial condition, liquidity, ability to finance planned capital expenditures, and results of operations;
- reducing the amount of oil, natural gas, and NGLs that we can produce economically;
- causing us to delay or postpone some of our capital projects;
- reducing our revenues, operating income, or cash flows;
- reducing the amounts of our estimated proved oil and natural-gas reserves;
- reducing the carrying value of our oil and natural-gas properties;
- reducing the standardized measure of discounted future net cash flows relating to oil and natural-gas reserves; and
- limiting our access to sources of capital, such as equity and long-term debt.

Our domestic operations are subject to governmental risks that may impact our operations.

Our domestic operations have been, and at times in the future may be, affected by political developments and are subject to complex federal, regional, state, tribal, local, and other laws and regulations such as restrictions on production, permitting, changes in taxes, deductions, royalties and other amounts payable to governments or governmental agencies, price or gathering-rate controls, hydraulic fracturing, and environmental protection regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals, and certificates from various federal, regional, state, tribal, and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws, including environmental and tax laws and regulations, are revised or reinterpreted, or if new laws and regulations become applicable to our operations. For example, Congress, from time to time, has considered adopting legislation that could adversely affect our business, financial condition, results of operations, or cash flows related to the following:

- *Climate Change.* Congress has considered climate-change legislation that would seek to reduce emissions of green-house gases (GHGs) through establishment of a "cap-and-trade" plan. It is not possible at this time to predict whether or when Congress may re-introduce or act on climate-change legislation. The U.S. Environmental Protection Agency (EPA) has made findings that emissions of GHGs present a danger to public health and the environment and, based on these findings, has adopted regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act, including one that requires a reduction in emissions of GHGs from motor vehicles and another that requires certain construction and operating permit reviews for GHG emissions from certain large stationary sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHGs from certain sources, including, among others, onshore and offshore oil and natural-gas production facilities, which includes certain of our operations, on an annual basis. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.
- *Taxes.* The U.S. President's Fiscal Year 2013 Budget Proposal includes provisions that would, if enacted, make significant changes to U.S. tax laws. These changes include, but are not limited to, (i) eliminating the immediate deduction for intangible drilling and development costs, (ii) eliminating the deduction from income for domestic production activities relating to oil and natural-gas exploration and development, and (iii) implementing certain international tax reforms.

Federal, state, and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, and adversely affect our production.

Hydraulic fracturing is an essential and common practice used to stimulate production of natural gas and/or oil from dense subsurface rock formations such as shales that generally exist between 4,000 and 14,000 feet below ground. We routinely apply hydraulic-fracturing techniques in many of our U.S. onshore oil and natural-gas drilling and completion programs. The process involves the injection of water, sand, and additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations, which are held open by the grains of sand, enabling the oil or natural gas to flow to the wellbore. The process is typically regulated by state oil and natural-gas commissions; however, the EPA, recently asserted federal regulatory authority over certain hydraulic-fracturing activities involving diesel under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. In February 2012, the DOI released draft regulations governing hydraulic fracturing on federal and Indian oil and gas leases to require disclosure of information regarding the chemicals used in hydraulic fracturing, advance approval for well-stimulation activities, mechanical integrity testing of casing, and monitoring of well-stimulation operations. In addition, Congress, from time to time, has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process. In the event that a new, federal level of legal restrictions relating to the hydraulic-fracturing process are adopted in areas where we currently or in the future plan to operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

Certain states in which we operate, including Colorado, Pennsylvania, Louisiana, Texas, and Wyoming, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure, and additional well-construction requirements on hydraulic-fracturing operations. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas and the public of certain information regarding the components used in the hydraulic-fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general and/or hydraulic fracturing in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, in the event state or local restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic-fracturing practices, and a committee of the U.S. House of Representatives has conducted an investigation of hydraulic-fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic-fracturing activities and plans to propose these standards by 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Also, the DOI is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. These ongoing or proposed studies, depending on any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

The adoption of derivatives legislation by the U.S. Congress could have an adverse effect on the Company's ability to use derivative instruments to reduce the effect of commodity price, interest rate, and other risks associated with its business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), signed into law in 2010, establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. The new legislation required the Commodities Futures Trading Commission (CFTC) and the Securities and Exchange Commission (SEC) to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In July 2011, the CFTC granted temporary exemptive relief from certain swap regulation provisions of the legislation until December 21, 2011, or until the agency finalized the corresponding rules. In December 2011, the CFTC extended the potential latest expiration date of the exemptive relief to July 16, 2012. In its rulemaking under the new legislation, the CFTC has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain *bona fide* hedging transactions or positions are exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize other regulations, including critical rulemaking on the definition of "swap", "swap dealer" and "major swap participant." Depending on the Company's classification, the financial reform legislation may require the Company to comply with margin requirements and with certain clearing and trade-execution requirements in connection with its derivative activities. The financial reform legislation may also require the counterparties to the Company's derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks the Company encounters, reduce the Company's ability to monetize or restructure its existing derivative contracts, and increase the Company's exposure to less creditworthy counterparties. If the Company reduces its use of derivatives as a result of the legislation and regulations, the Company's results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect the Company's ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural-gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. The Company's revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on the Company's consolidated financial position, results of operations, or cash flows.

Our debt and other financial commitments may limit our financial and operating flexibility.

Our total debt was $15.2 billion at December 31, 2011. We also have various commitments for leases, drilling contracts, derivative contracts, firm transportation, and purchase obligations for services and products. Our financial commitments could have important consequences to our business including, but not limited to:

- increasing our vulnerability to general adverse economic and industry conditions;
- limiting our ability to fund future working capital and capital expenditures, to engage in future acquisitions or development activities, or to otherwise realize the value of our assets and opportunities fully because of the need to dedicate a substantial portion of our cash flows from operations to payments on our debt or to comply with any restrictive terms of our debt;
- limiting our flexibility in planning for, or reacting to, changes in the industry in which we operate; and
- placing us at a competitive disadvantage compared to our competitors that have less debt and/or fewer financial commitments.

Additionally, the credit agreement governing our senior secured revolving credit facility ($5.0 billion Facility) contains a number of covenants that impose operating and financial constraints on the Company, including restrictions on our ability to:

- incur additional indebtedness;
- sell assets; and
- incur liens.

Provisions of the $5.0 billion Facility also require us to maintain specified financial covenants as further described in *Liquidity and Capital Resources* under Item 7 of this Form 10-K. Our ability to meet such covenants may be affected by events beyond our control.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

As of December 31, 2011, our debt was rated "BBB-" with a stable outlook by Standard and Poor's (S&P), "BBB-" with a negative outlook by Fitch Ratings (Fitch), and "Ba1" and under review for upgrade by Moody's Investors Service (Moody's). Although we are not aware of any current plans of S&P, Fitch, or Moody's to lower their respective ratings on our debt, our credit ratings may be subject to future downgrades. A downgrade in our credit ratings could negatively impact our cost of capital or our ability to effectively execute aspects of our strategy. If we were to be downgraded, it could be difficult for us to raise debt in the public debt markets and the cost of that new debt could be much higher than our outstanding debt. In addition, a downgrade could affect the Company's requirements to provide financial assurance of its performance under certain contractual arrangements and derivative agreements. See *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Our proved reserves are estimates. Any material inaccuracies in our reserve estimates or assumptions underlying our reserve estimates could cause the quantities and net present value of our reserves to be overstated or understated.

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control that could cause the quantities and net present value of our reserves to be overstated or understated. The reserve information included or incorporated by reference in this report represents estimates prepared by our internal engineers. The procedures and methods for estimating the reserves by our internal engineers were reviewed by independent petroleum consultants; however, no reserve audit was conducted by these consultants. Estimation of reserves is not an exact science. Estimates of economically recoverable oil and natural-gas reserves and of future net cash flows depend on a number of variable factors and assumptions, any of which may cause actual results to vary considerably from these estimates, such as:

- historical production from an area compared with production from similar producing areas;
- assumed effects of regulation by governmental agencies and court rulings;
- assumptions concerning future oil and natural-gas prices, future operating costs and capital expenditures; and
- estimates of future severance and excise taxes, workover, and remedial costs.

Estimates of reserves based on risk of recovery and estimates of expected future net cash flows prepared by different engineers, or by the same engineers at different times, may vary substantially. Actual production, revenues, and expenditures with respect to our reserves will likely vary from estimates, and the variance may be material. The discounted cash flows included in this report should not be construed as the fair value of the estimated oil, natural-gas, and NGLs reserves attributable to our properties. For the December 31, 2011, 2010, and 2009 reserves, in accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are based on average 12-month sales prices using the average beginning-of-month price, while reserves for all periods prior to December 31, 2009, are based on year-end sales prices. Actual future prices and costs may differ materially from the SEC regulation-compliant prices used for purposes of estimating future discounted net cash flows from proved reserves.

Failure to replace reserves may negatively affect our business.

Our future success depends upon our ability to find, develop, or acquire additional oil and natural-gas reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. We may be unable to find, develop, or acquire additional reserves on an economic basis. Furthermore, if oil and natural-gas prices increase, our costs for finding or acquiring additional reserves could also increase.

Poor general economic, business, or industry conditions may have a material adverse effect on our results of operations, liquidity, and financial condition.

During the last few years, concerns over inflation, energy costs, geopolitical issues, the availability and cost of credit, the U.S. mortgage market, uncertainties with regard to European sovereign debt, and a declining real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. Concerns about global economic conditions have had a significant adverse impact on global financial markets and commodity prices. If the economic recovery in the United States or abroad remains prolonged, demand for petroleum products could diminish or stagnate, which could impact the price at which we can sell our oil, natural gas, and NGLs, affect our vendors', suppliers' and customers' ability to continue operations, and ultimately adversely impact our results of operations, liquidity, and financial condition.

Our results of operations could be adversely affected by goodwill impairments.

As a result of mergers and acquisitions, we have approximately $5.6 billion of goodwill on our Consolidated Balance Sheet. Goodwill must be tested at least annually for impairment, and more frequently when circumstances indicate likely impairment. Goodwill is considered impaired to the extent that its carrying amount exceeds its implied fair value. Various factors could lead to an impairment of goodwill, such as the Company's inability to replace the value of its depleting asset base, or other adverse events, such as lower sustained oil and natural-gas prices, which could reduce the fair value of the associated reporting unit. An impairment of goodwill could have a substantial negative effect on our profitability.

We are subject to complex laws and regulations relating to environmental protection that can adversely affect the cost, manner, and feasibility of doing business.

Our operations and properties are subject to numerous federal, regional, state, tribal, local, and foreign laws and regulations relating to environmental protection from the time projects commence until abandonment. These laws and regulations govern, among other things:

- the amounts and types of substances and materials that may be released;
- the issuance of permits in connection with exploration, drilling, production, and midstream activities;
- the protection of endangered species;
- the release of emissions;
- the discharge and disposition of generated waste materials;
- offshore oil and gas operations;
- the reclamation and abandonment of wells and facility sites; and
- the remediation of contaminated sites.

In addition, these laws and regulations may impose substantial liabilities for our failure to comply or for any contamination resulting from our operations. Future environmental laws and regulations, such as the designation of previously unprotected species as threatened or endangered in areas where we operate, may negatively impact our industry. The cost of satisfying these requirements may have an adverse effect on our financial condition, results of operations, or cash flows or could result in limitations on our exploration and production activities, which could have an adverse impact on our ability to develop and produce our reserves. For a description of certain environmental proceedings in which we are involved, see *Note 16—Contingencies* and *Note 2—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

We are vulnerable to risks associated with our offshore operations that could negatively impact our operations and financial results.

We conduct offshore operations in the Gulf of Mexico, Ghana, Mozambique, Brazil, China, New Zealand, and other countries. Our operations and financial results could be significantly impacted by conditions in some of these areas because we are vulnerable to certain unique risks associated with operating offshore, including those relating to:

- hurricanes and other adverse weather conditions;
- oil field service costs and availability;
- compliance with environmental and other laws and regulations;

- terrorist attacks, such as piracy;
- remediation and other costs and regulatory changes resulting from oil spills or releases of hazardous materials; and
- failure of equipment or facilities.

In addition, we conduct some of our exploration in deep waters (greater than 1,000 feet) where operations are more difficult and costly than in shallower waters. The deep waters in the Gulf of Mexico, as well as international deepwater locations, lack the physical and oilfield service infrastructure present in its shallower waters. As a result, deepwater operations may require significant time between a discovery and the time that we can market our production, thereby increasing the risk involved with these operations.

Further, production of reserves from reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in many other producing regions of the world. This results in recovery of a relatively higher percentage of reserves from properties in the Gulf of Mexico during the initial few years of production and, as a result, our reserve replacement needs from new prospects may be greater there than for our operations elsewhere. Also, our revenues and return on capital will depend significantly on prices prevailing during these relatively short production periods.

We operate in other countries and are subject to political, economic, and other uncertainties.

Our operations outside the United States are based primarily in Algeria, Brazil, China, Cote d'Ivoire, Ghana, Indonesia, Liberia, Mozambique, Sierra Leone, and New Zealand. As a result, we face political and economic risks and other uncertainties with respect to our international operations. These risks may include, among other things:

- loss of revenue, property, and equipment as a result of hazards such as expropriation, war, piracy, acts of terrorism, insurrection, civil unrest, and other political risks;
- transparency issues in general and, more specifically, the U.S. Foreign Corrupt Practices Act, the U.K. Bribery Act, and other anti-corruption compliance issues;
- increases in taxes and governmental royalties;
- unilateral renegotiation of contracts by governmental entities;
- redefinition of international boundaries or boundary disputes;
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations;
- changes in laws and policies governing operations of foreign-based companies;
- foreign-exchange restrictions; and
- international monetary fluctuations and changes in the relative value of the U.S. dollar as compared to the currencies of other countries in which we conduct business.

For example, in 2006, the Algerian parliament approved legislation establishing an exceptional profits tax on foreign companies' Algerian oil production and issued regulations implementing this legislation. In response to the Algerian government's imposition of the exceptional profits tax, we notified Sonatrach of our disagreement with the collection of the exceptional profits tax. In February 2009, we initiated arbitration against Sonatrach with regard to the exceptional profits tax. The arbitration hearing related to Anadarko's dispute regarding the imposition of the Algerian exceptional profits tax was held in June 2011. Any decision issued by the arbitration panel is binding on the parties. For additional information, see *Note 17—Other Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

In addition, Ghana and Cote d'Ivoire are currently engaged in a dispute regarding the international maritime and land boundaries between the two countries. As a result, Cote d'Ivoire claims to be entitled to the maritime area which covers a portion of the Deepwater Tano Block where we are currently conducting exploration and appraisal activities. In the event Cote d'Ivoire is successful in its maritime border claims, our operations in the block could be materially impacted.

Recently, outbreaks of civil and political unrest have occurred in several countries in Africa and the Middle East, including countries where we conduct operations, such as Algeria and Cote d'Ivoire. As exhibited by the events in Tunisia, Egypt, and Libya, these outbreaks have resulted in the established governing body being overthrown. Continued or escalated civil and political unrest in the countries in which we operate could result in our curtailing operations. In the event that countries in which we operate experience political or civil unrest, especially in events where such unrest leads to an unseating of the established government, our operations in such country could be materially impaired.

Our international operations may also be adversely affected by laws and policies of the United States affecting foreign trade and taxation.

Realization of any of the factors listed above could materially and adversely affect our financial position, results of operations, or cash flows.

Our commodity-price risk-management and trading activities may prevent us from fully benefiting from price increases and may expose us to other risks.

To the extent that we engage in commodity-price risk-management activities to protect our cash flows from commodity-price declines, we may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our commodity-price risk-management and trading activities may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than the hedged volumes;
- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our hedging or other price-risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural-gas prices.

The credit risk of financial institutions could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, investment funds and other institutions. These transactions expose us to credit risk in the event of default by our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill existing obligations to us and their willingness to enter into future transactions with us. We have exposure to these financial institutions through our derivative transactions. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender's commitment under our credit facility.

We are not insured against all of the operating risks to which our business is exposed.

Our business is subject to all of the operating risks normally associated with the exploration for and production, gathering, processing, and transportation of oil and gas, including blowouts, cratering and fire, any of which could result in damage to, or destruction of, oil and natural-gas wells or formations, production facilities, and other property, as well as injury to persons. For protection against financial loss resulting from these operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/control of a well, comprehensive general liability, aviation liability, and worker's compensation and employer's liability. However, our insurance coverage may not be sufficient to cover us against 100% of potential losses arising as a result of the foregoing, and for certain risks, such as political risk, business interruption, war, terrorism, and piracy, for which we have limited or no coverage. In addition, we are not insured against all risks in all aspects of our business, such as hurricanes. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

Material differences between the estimated and actual timing of critical events may affect the completion of and commencement of production from development projects.

We are involved in several large development projects. Key factors that may affect the timing and outcome of such projects include:

- project approvals by joint-venture partners;
- timely issuance of permits and licenses by governmental agencies;
- weather conditions;
- availability of personnel;
- manufacturing and delivery schedules of critical equipment; and
- commercial arrangements for pipelines and related equipment to transport and market hydrocarbons.

Delays and differences between estimated and actual timing of critical events may affect the forward-looking statements related to large development projects and could have a material adverse effect on our results of operations.

The oil and gas exploration and production industry is very competitive, and some of our exploration and production competitors have greater financial and other resources than we do.

The oil and gas business is highly competitive in the search for and acquisition of reserves and in the gathering and marketing of oil and gas production. Our competitors include national oil companies, major oil and gas companies, independent oil and gas companies, individual producers, gas marketers, and major pipeline companies, as well as participants in other industries supplying energy and fuel to consumers. Some of our competitors may have greater and more diverse resources upon which to draw than we do. If we are not successful in our competition for oil and gas reserves or in our marketing of production, our financial condition and results of operations may be adversely affected.

The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, or qualified personnel. During these periods, the costs of rigs, equipment, supplies, and personnel are substantially greater and their availability to us may be limited. Additionally, these services may not be available on commercially reasonable terms. The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

Our drilling activities may not be productive.

Drilling for oil and natural gas involves numerous risks, including the risk that we will not encounter commercially productive oil or natural-gas reservoirs. The costs of drilling, completing, and operating wells are often uncertain, and drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- fires, explosions, blowouts, and surface cratering;
- marine risks such as capsizing, collisions, and hurricanes;
- title problems;
- other adverse weather conditions; and
- shortages or delays in the delivery of equipment.

Certain of our future drilling activities may not be successful and, if unsuccessful, this failure could have an adverse effect on our future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. Because of the percentage of our capital budget devoted to high-risk exploratory projects, it is likely that we will continue to experience significant exploration and dry hole expenses.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital and lead to unexpected future costs.

Our ability to sell our gas and oil production could be materially harmed if we fail to obtain adequate services such as transportation.

The marketability of our production depends in part on the availability, proximity, and capacity of pipeline facilities and tanker transportation. If any pipelines or tankers become unavailable, we would, to the extent possible, be required to find a suitable alternative to transport the natural gas and oil, which could increase our costs and/or reduce the revenues we might obtain from the sale of the gas and oil.

Provisions in our corporate documents and Delaware law could delay or prevent a change of control of Anadarko, even if that change would be beneficial to our stockholders.

Our restated certificate of incorporation and by-laws contain provisions that may make a change of control of Anadarko difficult, even if it may be beneficial to our stockholders, including provisions governing the nomination and removal of directors; the prohibition of stockholder action by written consent and regulation of stockholders' ability to bring matters for action before annual stockholder meetings; and the authorization given to our Board of Directors to issue and set the terms of preferred stock.

In addition, Section 203 of the Delaware General Corporation Law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock.

We may reduce or cease to pay dividends on our common stock.

We can provide no assurance that we will continue to pay dividends at the current rate or at all. The amount of cash dividends, if any, to be paid in the future will depend on actions taken by our Board of Directors, as well as, our financial condition, results of operations, cash flows, levels of capital and exploration expenditures, future business prospects, expected liquidity needs, and other related matters that our Board of Directors deems relevant.

The loss of key members of our management team, or difficulty attracting and retaining experienced technical personnel, could reduce our competitiveness and prospects for future success.

The successful implementation of our strategies and handling of other issues integral to our future success will depend, in part, on our experienced management team. The loss of key members of our management team could have an adverse effect on our business. We do not carry key man insurance. Our exploratory drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced explorationists, engineers, and other professionals. Competition for such professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

Item 1B. Unresolved Staff Comments

The Company has no unresolved SEC staff comments that have been outstanding greater than 180 days from December 31, 2011.

Item 3. Legal Proceedings

GENERAL The Company is a defendant in a number of lawsuits and is involved in governmental proceedings and regulatory controls arising in the ordinary course of business, including, but not limited to, personal injury claims, title disputes, royalty claims, contract claims, oil-field contamination claims, and environmental claims, including claims involving assets owned by predecessors of acquired companies. While the ultimate outcome and impact on the Company cannot be predicted with certainty, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's consolidated financial position, results of operations, or cash flows.

See *Note 2—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K, which is incorporated herein by reference, for a discussion of legal proceedings related to the Deepwater Horizon events.

See *Note 16—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K, which is incorporated herein by reference, for a discussion of other material legal proceedings to which the Company is a party.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

MARKET INFORMATION, HOLDERS, AND DIVIDENDS

As of January 31, 2012, there were approximately 13,700 record holders of Anadarko common stock. The common stock of Anadarko is traded on the New York Stock Exchange. The following shows information regarding the market price of and dividends declared and paid on the Company's common stock by quarter for 2011 and 2010.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2011				
Market Price				
High	**$ 84.00**	**$ 85.50**	**$ 85.25**	**$ 84.42**
Low	**$ 73.02**	**$ 68.67**	**$ 63.03**	**$ 57.11**
Dividends	**$ 0.09**	**$ 0.09**	**$ 0.09**	**$ 0.09**
2010				
Market Price				
High	$ 73.89	$ 75.07	$ 58.42	$ 78.98
Low	$ 60.75	$ 34.54	$ 36.06	$ 55.65
Dividends	$ 0.09	$ 0.09	$ 0.09	$ 0.09

The amount of future common stock dividends will depend on earnings, financial condition, capital requirements, the effect a dividend payment would have on the Company's compliance with its financial covenants, and other factors, and will be determined by the Board of Directors on a quarterly basis. For additional information, see *Liquidity and Capital Resources—Uses of Cash—Dividends* under Item 7 of this Form 10-K.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth information with respect to the equity compensation plans available to directors, officers, and employees of the Company at December 31, 2011.

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))
Equity compensation plans approved by security holders	9,868,589	$ 55.27	15,474,224
Equity compensation plans not approved by security holders	—	—	—
Total	9,868,589	$ 55.27	15,474,224

PURCHASES OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PERSONS

The following sets forth information with respect to repurchases made by the Company of its shares of common stock during the fourth quarter of 2011.

Period	Total number of shares purchased[1]	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Approximate dollar value of shares that may yet be purchased under the plans or programs
October 1-31	175	$ 63.05	—	
November 1-30	83,614	$ 78.47	—	
December 1-31	40,517	$ 80.38	—	
Fourth Quarter 2011	124,306	$ 79.07	—	$ —

(1) During the fourth quarter of 2011, all purchased shares related to stock received by the Company for the payment of withholding taxes due on employee stock plan share issuances.

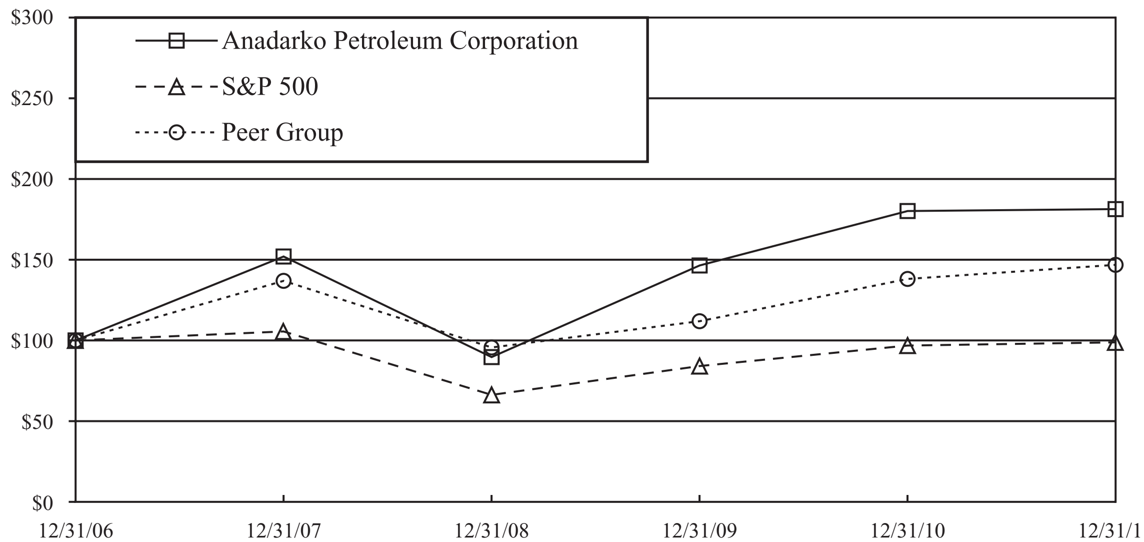
For additional information, see *Note 14—Share-Based Compensation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

PERFORMANCE GRAPH

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

The following graph compares the cumulative five-year total return to stockholders on Anadarko's common stock relative to the cumulative total returns of the S&P 500 index and a peer group of 11 companies. The companies included in the peer group are Apache Corporation; Chevron Corporation; ConocoPhillips; Devon Energy Corporation; EOG Resources, Inc.; Hess Corporation; Marathon Oil Corporation; Noble Energy, Inc.; Occidental Petroleum Corporation; Pioneer Natural Resources Company; and Plains Exploration and Production Company.

Comparison of 5-Year Cumulative Total Return Among Anadarko Petroleum Corporation, the S&P 500 Index and a Peer Group



An investment of $100 (with reinvestment of all dividends) is assumed to have been made in the Company's common stock, in the index and in the peer group on December 31, 2006, and its relative performance is tracked through December 31, 2011.

Fiscal Year Ended December 31	2006	2007	2008	2009	2010	2011
Anadarko Petroleum Corporation	$ 100.00	$ 152.04	$ 89.83	$ 146.59	$ 179.98	$ 181.24
S&P 500	100.00	105.49	66.46	84.05	96.71	98.75
Peer Group	100.00	137.07	95.49	112.00	138.00	147.01

Item 6. Selected Financial Data

millions except per-share amounts	Summary Financial Information[1] 2011	2010	2009	2008	2007
Sales Revenues	**$ 13,882**	$ 10,842	$ 8,210	$ 14,079	$ 11,656
Gains (Losses) on Divestitures and Other, net	**85**	142	133	1,083	4,760
Reversal of Accrual for DWRRA Dispute	**—**	—	657	—	—
Total Revenues and Other	**13,967**	10,984	9,000	15,162	16,416
Deepwater Horizon settlement and related costs	**3,930**	15	—	—	—
Operating Income (Loss)	**(1,870)**	1,769	377	5,601	7,871
Income (Loss) from Continuing Operations	**(2,568)**	821	(103)	3,220	3,767
Income from Discontinued Operations, net of taxes	**—**	—	—	63	11
Net Income (Loss) Attributable to Common Stockholders	**(2,649)**	761	(135)	3,260	3,778
Per Common Share (amounts attributable to common stockholders):					
Income (Loss) from Continuing Operations—Basic	**$ (5.32)**	$ 1.53	$ (0.28)	$ 6.79	$ 8.01
Income (Loss) from Continuing Operations—Diluted	**$ (5.32)**	$ 1.52	$ (0.28)	$ 6.78	$ 7.99
Income from Discontinued Operations—Basic	**$ —**	$ —	$ —	$ 0.13	$ 0.02
Income from Discontinued Operations—Diluted	**$ —**	$ —	$ —	$ 0.13	$ 0.02
Net Income (Loss)—Basic	**$ (5.32)**	$ 1.53	$ (0.28)	$ 6.92	$ 8.03
Net Income (Loss)—Diluted	**$ (5.32)**	$ 1.52	$ (0.28)	$ 6.91	$ 8.01
Dividends	**$ 0.36**	$ 0.36	$ 0.36	$ 0.36	$ 0.36
Average Number of Common Shares Outstanding—Basic	**498**	495	480	465	465
Average Number of Common Shares Outstanding—Diluted	**498**	497	480	466	467
Cash Provided by Operating Activities—Continuing Operations	**$ 2,505**	$ 5,247	$ 3,926	$ 6,447	$ 2,766
Cash Provided by (Used in) Operating Activities—Discontinued Operations	**—**	—	—	(5)	134
Net Cash Provided by Operating Activities	**2,505**	5,247	3,926	6,442	2,900
Capital Expenditures	**$ 6,553**	$ 5,169	$ 4,558	$ 4,881	$ 3,990
Current Debt	**$ 170**	$ 291	$ —	$ 1,472	$ 1,396
Long-term Debt	**15,060**	12,722	11,149	9,128	11,151
Midstream Subsidiary Note Payable to a Related Party	**—**	—	1,599	1,739	2,200
Total Debt	**$ 15,230**	$ 13,013	$ 12,748	$ 12,339	$ 14,747
Total Stockholders' Equity	**18,105**	20,684	19,928	18,795	16,364
Total Assets	**$ 51,779**	$ 51,559	$ 50,123	$ 48,923	$ 48,451
Annual Sales Volumes:					
Natural Gas (Bcf)	**852**	829	809	750	698
Oil and Condensate (MMBbls)	**79**	74	68	67	79
Natural Gas Liquids (MMBbls)	**27**	23	17	14	16
Total (MMBOE)[2]	**248**	235	220	206	211
Average Daily Sales Volumes:					
Natural Gas (MMcf/d)	**2,334**	2,272	2,217	2,049	1,912
Oil and Condensate (MBbls/d)	**217**	201	187	182	215
Natural Gas Liquids (MBbls/d)	**74**	63	47	39	43
Total (MBOE/d)	**680**	643	604	563	577
Proved Reserves:					
Natural-Gas Reserves (Tcf)	**8.4**	8.1	7.8	8.1	8.5
Oil and Condensate Reserves (MMBbls)	**771**	749	733	709	843
Natural-Gas Liquids Reserves (MMBbls)	**374**	320	277	217	171
Total Proved Reserves (MMBOE)	**2,539**	2,422	2,304	2,277	2,431
Number of Employees	**4,800**	4,400	4,300	4,300	4,000

(1) Consolidated for Anadarko and its subsidiaries. Certain amounts for prior years have been reclassified to conform to the current presentation.

(2) Natural gas is converted to equivalent barrels at the rate of 6,000 cubic feet of gas per barrel.

Table of Measures

Bcf—Billion cubic feet	MBbls/d—Thousand barrels per day
MMBbls—Million barrels	MBOE/d—Thousand barrels of oil equivalent per day
MMBOE—Million barrels of oil equivalent	Tcf—Trillion cubic feet
MMcf/d—Million cubic feet per day	

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read together with the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements*, which are included in this report in Item 8, and the information set forth in *Risk Factors* under Item 1A. Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries.

OVERVIEW

Anadarko achieved its key operational objectives in 2011 by increasing sales volumes by approximately 6% year-over-year and adding 392 million barrels of oil equivalent (BOE) of proved reserves. Additionally, the Company continued its offshore exploration and appraisal drilling success with an approximate 80% success rate for wells completed in 2011. Anadarko ended 2011 with $2.7 billion cash on hand and $2.1 billion available under its five-year $5.0 billion senior secured revolving credit facility ($5.0 billion Facility), as well as additional access to credit and capital markets as needed. Management believes that the Company is positioned to satisfy its operational objectives and capital commitments with cash on hand, available borrowing capacity, and cash flows from operations.

Mission and Strategy

Anadarko's mission is to deliver a competitive and sustainable rate of return to shareholders by exploring for, acquiring, and developing oil and natural-gas resources vital to the world's health and welfare. Anadarko employs the following strategy to achieve this mission:

- identify and commercialize resources;
- explore in high-potential, proven basins;
- employ a global business development approach; and
- ensure financial discipline and flexibility.

Developing a portfolio of primarily unconventional resources provides the Company a stable base of capital-efficient, predictable, and repeatable development opportunities which, in turn, positions the Company for consistent growth at competitive rates.

Exploring in high-potential, proven, and emerging basins worldwide provides the Company with growth opportunities. Anadarko's exploration success has created value by expanding its future resource potential, while providing the flexibility to manage risk by monetizing discoveries.

Anadarko's global business development approach transfers core skills across the globe to assist in the discovery and development of world-class resources that are accretive to the Company's performance. These resources help form an optimized global portfolio where both surface and subsurface risks are actively managed.

A strong balance sheet is essential for the development of the Company's assets, and Anadarko is committed to disciplined investments in its businesses to manage through commodity price cycles. Maintaining financial discipline enables the Company to capitalize on the flexibility of its global portfolio, while allowing the Company to pursue new strategic growth opportunities.

Deepwater Horizon Settlement and Indemnity

In October 2011, the Company and BP Exploration & Production Inc. (BP) entered into a settlement agreement, mutual releases, and agreement to indemnify, relating to the Deepwater Horizon events (Settlement Agreement). Pursuant to the Settlement Agreement, the Company paid $4.0 billion and transferred its interest in the Macondo well and the Mississippi Canyon Block 252 lease (Lease) to BP, and BP accepted this consideration in full satisfaction of its claims against Anadarko for $6.1 billion of invoices issued through the settlement date as well as for potential reimbursements of subsequent costs incurred by BP related to the Deepwater Horizon events, including costs under the Operating Agreement (OA). In addition, BP fully indemnified Anadarko against all claims, causes of action, losses, costs, expenses, liabilities, damages, or judgments of any kind arising out of the Deepwater Horizon events, related damage claims arising under the Oil Pollution Act of 1990 (OPA), claims for natural resource damages (NRD) and associated damage-assessment costs, and any claims arising under the OA. This indemnification is guaranteed by BP Corporation North America Inc. (BPCNA) and, in the event that the net worth of BPCNA declines below an agreed-upon amount, BP p.l.c. has agreed to become the sole guarantor. Under the Settlement Agreement, BP does not indemnify the Company against fines and penalties, punitive damages, shareholder, derivative, or security laws claims, or certain other claims. The Company believes that costs associated with any non-indemnified items, individually or in the aggregate, will not materially impact the Company's consolidated financial position, results of operations, or cash flows. Refer to *Note 2—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion and analysis of these events.

Operating Highlights

Significant 2011 operating highlights include the following:

Overall

- Anadarko's total-year sales volumes were 248 MMBOE, representing a 6% increase over 2010.
- Anadarko achieved liquids sales volumes of 106 MMBOE, representing a 10% increase over 2010.
- The Company achieved an approximate 80% success rate from offshore exploration and appraisal drilling completed in 2011.

United States Onshore

- The Company's Rocky Mountains Region (Rockies) achieved total-year sales volumes of 303 thousand barrels of oil equivalent per day (MBOE/d), representing a 10% increase over 2010.
- The Company's Southern and Appalachia Region achieved total-year sales volumes of 146 MBOE/d, representing a 17% increase over 2010, primarily due to increased drilling in the Eagleford and Marcellus shales.
- The Company entered into a joint-venture agreement that requires a third-party joint-venture partner to fund up to $1.6 billion of Anadarko's future capital costs in exchange for a one-third interest in Anadarko's Eagleford shale assets.
- The Company increased its ownership interest in a natural-gas processing plant (Wattenberg Plant), located in northeast Colorado, by acquiring an additional 93% interest for $576 million. The Company operates and owns a 100% interest in the Wattenberg Plant.
- Western Gas Partners, LP (WES), a consolidated subsidiary of the Company, acquired a natural-gas processing plant and related gathering systems (Platte Valley), located in northeast Colorado, for $302 million.
- Anadarko has accumulated over 370,000 gross acres in the prospective liquids-rich area of the eastern Ohio Utica shale.

Gulf of Mexico

- The Company's Gulf of Mexico total-year sales volumes were 131 MBOE/d, representing a 15% decrease from 2010.
- Anadarko and its partners finalized a unitization agreement to develop the Lucius field, which was sanctioned in December 2011. Anadarko will operate the unit and has a 35% working interest in the field.
- The Company received drilling permits for one development well and two exploration appraisal wells, including the Cheyenne East well, Anadarko's first deepwater discovery since the deepwater drilling moratorium.

International

- The Company's International total-year sales volumes were 85 MBOE/d, representing a 20% increase from 2010.
- The Company completed drilling five successful exploration wells; three in Ghana and two in Mozambique.
- The Company completed drilling seven successful appraisal wells; four in Ghana, two in Mozambique, and one in Brazil.

Financial Highlights

Significant 2011 financial highlights include the following:

- Anadarko's net loss attributable to common stockholders for 2011, including the effect of the $4.0 billion payment made as a result of the Settlement Agreement, totaled $2.6 billion compared to net income of $761 million in 2010.
- The Company generated $2.5 billion of cash flows from operations, including the effect of the $4.0 billion payment required by the Settlement Agreement, compared to $5.2 billion in 2010 and ended the year with $2.7 billion of cash on hand.
- The Company entered into an agreement with a financial institution to provide up to $400 million of letters of credit (LOC Facility) which lowered the Company's cost to issue letters of credit.
- The Company amended its $5.0 billion Facility to reduce maintenance costs and to lower interest rates under the facility by 125 basis points on borrowings and 30 basis points on undrawn amounts.
- Anadarko modified and extended swap maturity dates from October 2011 to June 2014 for certain of its interest-rate swaps with an aggregate notional principal of $1.85 billion to better align the swap portfolio with the anticipated timing of future debt issuances.
- The Company impaired $1.2 billion of oil and gas reporting segment properties and $458 million of midstream reporting segment properties.
- The Company restructured 500,000 MMBtu/d of natural-gas three-way collar positions into fixed-price commodity swap positions for one million MMBtu/d with an average price of $4.69 per MMBtu.
- The Company received $419 million in contingent consideration related to its 2008 divestiture of its interest in the Peregrino field offshore Brazil.

Gulf of Mexico Deepwater Drilling Update

In July and August 2011, the Bureau of Ocean Energy Management, Regulation and Enforcement, an agency of the Department of the Interior (DOI), issued drilling permits to Anadarko for the Heidelberg appraisal well, the Cheyenne East exploration well near the Independence Hub facility, and a development well in the Nansen field. Anadarko received a drilling permit for the Spartacus prospect in 2012 and is awaiting additional DOI approvals for other exploration plans and drilling permits. See *Note 16—Contingencies—Deepwater Drilling Moratorium and Other Related Matters* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information on the moratorium.

The following discussion pertains to Anadarko's results of operations, financial condition, and changes in financial condition. Any increases or decreases "for the year ended December 31, 2011" refer to the comparison of the year ended December 31, 2011, to the year ended December 31, 2010. Similarly, any increases or decreases "for the year ended December 31, 2010" refer to the comparison of the year ended December 31, 2010, to the year ended December 31, 2009. The primary factors that affect the Company's results of operations include commodity prices for natural gas, crude oil, and natural gas liquids (NGLs); sales volumes; the Company's ability to discover additional oil and natural-gas reserves; the cost of finding such reserves; and operating costs.

RESULTS OF OPERATIONS

Selected Data

millions except per-share amounts and percentages	**2011**	2010	2009
Financial Results			
Oil and condensate, natural-gas, and NGLs sales	**$ 12,834**	$ 10,009	$ 7,482
Gathering, processing, and marketing sales	**1,048**	833	728
Gains (losses) on divestitures and other, net	**85**	142	133
Reversal of accrual for DWRRA dispute	**—**	—	657
Total revenues and other	**13,967**	10,984	9,000
Costs and expenses[(1)]	**15,837**	9,215	8,623
Other (income) expense	**254**	128	485
Income tax expense (benefit)	**(856)**	820	(5)
Net income (loss) attributable to common stockholders	**$ (2,649)**	$ 761	$ (135)
Net income (loss) per common share attributable to common stockholders—diluted	**$ (5.32)**	$ 1.52	$ (0.28)
Average number of common shares outstanding—diluted	**498**	497	480
Operating Results			
Adjusted EBITDAX[(2)]	**$ 8,560**	$ 7,241	$ 6,033
Total proved reserves (MMBOE)	**2,539**	2,422	2,304
Annual sales volumes (MMBOE)	**248**	235	220
Capital Resources and Liquidity			
Cash provided by operating activities	**$ 2,505**	$ 5,247	$ 3,926
Capital expenditures	**6,553**	5,169	4,558
Total debt	**15,230**	13,013	12,748
Stockholders' equity	**$ 18,105**	$ 20,684	$ 19,928
Debt to total capitalization ratio	**45.7%**	38.6%	39.0%

MMBOE—millions of barrels of oil equivalent

(1) Includes Deepwater Horizon settlement and related costs of $3.9 billion and $15 million in 2011 and 2010, respectively.

(2) See *Operating Results—Segment Analysis—Adjusted EBITDAX* for a description of Adjusted EBITDAX, which is not a U.S. Generally Accepted Accounting Principles (GAAP) measure, and for a reconciliation of Adjusted EBITDAX to income (loss) before income taxes, which is presented in accordance with GAAP.

FINANCIAL RESULTS

Net Income (Loss) Attributable to Common Stockholders Anadarko's net loss attributable to common stockholders for 2011 totaled $2.6 billion, or $5.32 per share (diluted), compared to net income attributable to common stockholders for 2010 of $761 million, or $1.52 per share (diluted). Anadarko's net loss attributable to common stockholders in 2009 was $135 million, or $0.28 per share (diluted). Anadarko's net loss for 2011 included the effect of the $4.0 billion Settlement Agreement with BP related to the Deepwater Horizon events.

Sales Revenues and Volumes

millions except percentages	**2011**	Inc/(Dec) vs. 2010	2010	Inc/(Dec) vs. 2009	2009
Sales Revenues					
Natural-gas sales	**$ 3,300**	(4)%	$ 3,420	17%	$ 2,924
Oil and condensate sales	**8,072**	44	5,592	39	4,022
Natural-gas liquids sales	**1,462**	47	997	86	536
Total	$ 12,834	28	$ 10,009	34	$ 7,482

Anadarko's total sales revenues for the year ended December 31, 2011, increased primarily due to higher prices for crude oil and NGLs, as well as increased liquids volumes, partially offset by lower average natural-gas prices. Total sales revenues for the year ended December 31, 2010, increased primarily due to higher commodity prices and increased sales volumes.

millions	**Natural Gas**	**Oil and Condensate**	**NGLs**	**Total**
2009 sales revenues	$ 2,924	$ 4,022	$ 536	$ 7,482
Changes associated with prices	424	1,284	269	1,977
Changes associated with sales volumes	72	286	192	550
2010 sales revenues	$ 3,420	$ 5,592	$ 997	$ 10,009
Changes associated with prices	**(214)**	**2,055**	**295**	**2,136**
Changes associated with sales volumes	**94**	**425**	**170**	**689**
2011 sales revenues	**$ 3,300**	**$ 8,072**	**$ 1,462**	**$ 12,834**

The following table provides Anadarko's sales volumes for the years ended December 31, 2011, 2010, and 2009.

Sales Volumes	2011	Inc/(Dec) vs. 2010	2010	Inc/(Dec) vs. 2009	2009
Barrels of Oil Equivalent (MMBOE except percentages)					
United States	**217**	4%	209	7%	196
International	**31**	20	26	7	24
Total	**248**	6	235	7	220
Barrels of Oil Equivalent per Day (MBOE/d except percentages)					
United States	**595**	4%	572	7%	537
International	**85**	20	71	7	67
Total	**680**	6	643	7	604

Sales volumes represent actual production volumes adjusted for changes in commodity inventories. Anadarko employs marketing strategies to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. For additional information, see *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 and *Other (Income) Expense—(Gains) Losses on Commodity Derivatives, net*. Production of natural gas, crude oil, and NGLs is usually not affected by seasonal swings in demand.

Natural-Gas Sales Volumes, Average Prices, and Revenues

	2011	Inc/(Dec) vs. 2010	2010	Inc/(Dec) vs. 2009	2009
United States					
Sales volumes—Bcf	**852**	3%	829	2%	809
MMcf/d	**2,334**	3	2,272	2	2,217
Price per Mcf	**$ 3.87**	(6)	$ 4.12	14	$ 3.61
Natural-gas sales revenues (millions)	**$ 3,300**	(4)	$ 3,420	17	$ 2,924

Bcf—billion cubic feet
MMcf/d—million cubic feet per day

The Company's natural-gas sales volumes increased 62 MMcf/d for the year ended December 31, 2011, primarily due to increased sales volumes in the Rockies of 84 MMcf/d, resulting from increased drilling in the Greater Natural Buttes area and the Wattenberg field, as well as increased sales volumes in the Southern and Appalachia Region of 66 MMcf/d, primarily related to increased drilling in the Marcellus shale. These increases were partially offset by lower sales volumes in the Gulf of Mexico of 86 MMcf/d, primarily due to 2010 price-related royalty relief, which did not apply for 2011, as well as natural production declines.

The Company's natural-gas sales volumes increased 55 MMcf/d for the year ended December 31, 2010, primarily due to increased sales volumes in the Rockies of 61 MMcf/d, resulting from increased drilling in Greater Natural Buttes and the Greater Green River basins, as well as increased sales volumes in the Southern and Appalachia Region of 12 MMcf/d, associated with increased drilling in the Eagleford, Haynesville and Marcellus shales. These increases were partially offset by lower sales volumes in the Gulf of Mexico of 18 MMcf/d due to natural production declines.

The average natural-gas price Anadarko received decreased for the year ended December 31, 2011, primarily due the industry's supply growing at a faster pace than demand in 2011. Anadarko's average natural-gas price received increased for the year ended December 31, 2010, primarily due to an increase in demand.

Crude-Oil and Condensate Sales Volumes, Average Prices, and Revenues

	2011	Inc/(Dec) vs. 2010	2010	Inc/(Dec) vs. 2009	2009
United States					
Sales volumes—MMBbls	**48**	1%	48	7%	44
MBbls/d	**132**	1	130	7	120
Price per barrel	**$ 97.70**	30	$ 74.96	28	$ 58.56
International					
Sales volumes—MMBbls	**31**	20%	26	7%	24
MBbls/d	**85**	20	71	7	67
Price per barrel	**$ 109.20**	39	$ 78.52	33	$ 59.01
Total					
Sales volumes—MMBbls	**79**	8%	74	7%	68
MBbls/d	**217**	8	201	7	187
Total price per barrel	**$ 102.24**	34	$ 76.22	30	$ 58.72
Oil and condensate sales revenues (millions)	**$ 8,072**	44	$ 5,592	39	$ 4,022

MMBbls—million barrels
MBbls/d—thousand barrels per day

Anadarko's crude-oil and condensate sales volumes increased 16 MBbls/d for the year ended December 31, 2011. This increase primarily resulted from an additional 15 MBbls/d in Ghana, where the Company's first lifting occurred in the first quarter of 2011. Increased drilling in the Wattenberg field led to a 5 MBbls/d sales-volume improvement in the Rockies. Additionally, increased activity in the Eagleford shale and Bone Spring formation increased sales volumes from those areas by approximately 170%, contributing to an 8 MBbls/d sales-volume increase in the Southern and Appalachian Region. Partially offsetting these increases was a 9 MBbls/d sales-volume decline in the Gulf of Mexico principally caused by downtime for repairs at the Company's Constitution spar and a third-party oil pipeline in 2011, as well as natural production declines.

Anadarko's crude-oil and condensate sales volumes increased 14 MBbls/d for the year ended December 31, 2010. This increase was partially due to higher sales volumes of 5 MBbls/d in the Gulf of Mexico as repairs to third-party downstream infrastructure that was damaged in the 2008 hurricane season was completed during the third quarter of 2009. In addition, crude-oil sales volumes increased 4 MBbls/d in the Southern and Appalachia Region due to a shift in focus from drilling in dry-gas areas to drilling in liquids-rich areas and 3 MBbls/d in the Rockies due to realizing a full year of operations from an oil pipeline that was placed in service in mid-2009, as well as a shift in focus to liquids-rich areas. Also, Algerian crude-oil sales volumes increased 3 MBbls/d due to the timing of cargo liftings.

The average crude-oil price Anadarko received increased for the year ended December 31, 2011, as a result of increased global demand, as well as supply disruptions and unrest in the Middle East and North Africa. The average crude-oil price realized by the Company was enhanced by the widening differential between West Texas Intermediate and Brent crude, as approximately 70% of Anadarko's 2011 crude-oil sales volumes were based on prices that are either directly indexed to, or highly correlated to, Brent crude. Anadarko's average crude-oil price increased for the year ended December 31, 2010, primarily due to increased global demand.

Natural-Gas Liquids Sales Volumes, Average Prices, and Revenues

	2011	Inc/(Dec) vs. 2010	2010	Inc/(Dec) vs. 2009	2009
United States					
Sales volumes—MMBbls	**27**	17%	23	36%	17
MBbls/d	**74**	17	63	36	47
Price per barrel	**$ 53.95**	25	$ 43.07	37	$ 31.42
Natural-gas liquids sales revenues (millions)	**$ 1,462**	47	$ 997	86	$ 536

NGLs sales represent revenues from the sale of products derived from the processing of Anadarko's natural-gas production. The Company's NGLs sales volumes increased by 11 MBbls/d for the year ended December 31, 2011, as a result of the Company's increased focus on liquids-rich areas, expanded horizontal drilling programs in the Wattenberg field, and increases related to the Wattenberg Plant acquisition.

Anadarko's NGLs sales volumes increased 16 MBbls/d for the year ended December 31, 2010. The increased volumes primarily related to operations in the Rockies where an additional natural-gas processing train was brought online late in the second quarter of 2009. Additionally, improved recoveries in the Rockies resulted from new processing agreements entered into late in 2009.

The average NGLs price increased for the years ended December 31, 2011 and 2010, primarily due to higher crude-oil prices and sustained global petrochemical demand.

Gathering, Processing, and Marketing Margin

millions except percentages	2011	Inc/(Dec) vs. 2010	2010	Inc/(Dec) vs. 2009	2009
Gathering, processing, and marketing sales	**$ 1,048**	26%	$ 833	14%	$ 728
Gathering, processing, and marketing expenses	**791**	29	615	—	617
Margin	**$ 257**	18	$ 218	96	$ 111

For the year ended December 31, 2011, the gathering, processing, and marketing margin increased $39 million. This increase was primarily due to increased natural-gas processing margins from higher NGLs prices and volumes, lower prices for natural-gas purchases, and favorable impacts attributable to 2011 asset acquisitions. These increases were partially offset by lower margins associated with natural-gas sales from inventory.

For the year ended December 31, 2010, the gathering, processing, and marketing margin increased $107 million. The increase was primarily due to higher margins associated with natural-gas sales from inventory and increased NGLs volumes and prices. These increases were partially offset by the absence of gas-processing margins associated with assets divested in 2009.

Gains (Losses) on Divestitures and Other, net

Gains (losses) on divestitures in 2011 included losses on assets held for sale of $422 million as the Company began marketing certain onshore domestic properties from the oil and gas exploration and production reporting segment and the midstream reporting segment in order to redirect its operating activities and capital investment to other areas. These assets were impaired to fair value. See *Note 4—Divestitures and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. Also included is a loss of $76 million related to the effective termination of natural-gas processing contracts between the Company and the previous owner of the Wattenberg Plant that occurred in connection with the Company's purchase of the plant. The loss represents the aggregate amount by which the Company's contracts with the previous owner of the Wattenberg Plant were unfavorable as compared to current market transactions for the same or similar services at the date of the Company's acquisition of the plant. These losses were partially offset by a gain of $419 million related to the receipt and final settlement of contingent consideration related to the Company's 2008 divestiture of its interest in the Peregrino field offshore Brazil. Gains on divestitures also include the recognition of a $21 million gain from the acquisition-date fair-value remeasurement of the Company's pre-acquisition 7% equity interest in the Wattenberg Plant.

Gains on divestitures in 2010 were $29 million and related primarily to the divestiture of onshore U.S. oil and gas properties. Gains on divestitures in 2009 were $44 million, primarily related to the sale of oil and gas properties in Qatar.

Reversal of Accrual for DWRRA Dispute

In January 2006, the DOI issued an order (2006 Order) to Kerr-McGee Oil and Gas Corporation (KMOG), a subsidiary of Kerr-McGee Corporation (Kerr-McGee), to pay oil and gas royalties and accrued interest on KMOG's deepwater Gulf of Mexico production associated with eight 1996, 1997, and 2000 leases, for which KMOG considered royalties to be suspended under the Deepwater Royalty Relief Act (DWRRA). KMOG successfully appealed the 2006 Order, and the DOI's petition for a writ of certiorari with the U.S. Supreme Court was denied on October 5, 2009.

In 2009, based on the U.S. Supreme Court's denial of the DOI's petition for review by the court, Anadarko reversed its $657 million liability for accrued royalties on leases listed in the 2006 Order, similar orders to pay issued in 2008 and 2009, and other deepwater Gulf of Mexico leases with similar price-threshold provisions. In addition, the Company reversed its $78 million accrued liability for interest on these unpaid royalty amounts. Effective October 1, 2009, the Company ceased accruing liabilities for royalties and interest costs for deepwater Gulf of Mexico leases that have royalties suspended under the DWRRA. For more information on the DWRRA dispute, see *Note 16—Contingencies—Deepwater Royalty Relief Act* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Costs and Expenses

millions except percentages	**2011**	Inc/(Dec) vs. 2010	2010	Inc/(Dec) vs. 2009	2009
Oil and gas operating	**$ 993**	20%	$ 830	(3)%	$ 859
Oil and gas transportation and other	**891**	9	816	23	664
Exploration	**1,076**	10	974	(12)	1,107

For the year ended December 31, 2011, oil and gas operating expenses increased by $163 million primarily due to (i) increased workovers and related freight costs of $47 million primarily in the Gulf of Mexico and the Rockies, (ii) $36 million related to increased joint-venture activity primarily in the Rockies, Bone Spring and Marcellus shale in the Southern and Appalachia Region, and in Alaska, (iii) operating costs of $34 million resulting from the start of production in Ghana, and (iv) higher surface maintenance costs of $10 million primarily in the Rockies. For the year ended December 31, 2010, oil and gas operating expenses decreased primarily due to decreased workover costs of $28 million in the Gulf of Mexico as a result of the moratorium and associated delays in obtaining drilling permits.

For the year ended December 31, 2011, oil and gas transportation and other expenses increased $75 million due to higher volumes, higher natural-gas processing fees that rise with increases in NGLs prices, and increased costs attributable to growth in U.S. onshore plays. These increases were partially offset by the 2010 expensing of amounts attributable to drilling rig lease payments made for rigs that sat idle during the moratorium, as well as rig termination fees incurred in 2010 related to deepwater drilling rigs in the Gulf of Mexico. For the year ended December 31, 2010, oil and gas transportation and other expenses increased due to higher gas gathering and transportation costs of $77 million and $45 million, primarily attributable to increased production in the Rockies and the Southern and Appalachia Region, respectively, and the expensing of $27 million of drilling rig lease payments and $19 million of rig termination fees as discussed above. Partially offsetting this increase in oil and gas transportation and other expenses was $29 million of drilling rig contract termination fees incurred in 2009 as a result of low 2009 commodity prices.

Exploration expense increased $102 million for the year ended December 31, 2011, due to $143 million of higher geological and geophysical expense, primarily associated with increased seismic purchases in the Rockies, Gulf of Mexico, the Marcellus shale, Indonesia, Liberia, and East Africa. These additional expenses were partially offset by $48 million of lower dry hole expense, primarily in the Gulf of Mexico. Exploration expense decreased $133 million for the year ended December 31, 2010, primarily due to a $128 million decline in dry hole expense in the United States, and lower exit costs of $15 million in various international locations, partially offset by higher dry hole expense of $26 million in various other international locations, including Brazil, Ghana, and Mozambique. Exploration expense for 2010 included a $46 million increase related to the Macondo well in the Gulf of Mexico.

millions except percentages	**2011**	Inc/(Dec) vs. 2010	2010	Inc/(Dec) vs. 2009	2009
General and administrative	**$ 1,060**	10%	$ 967	(2)%	$ 983
Depreciation, depletion, and amortization	**3,830**	3	3,714	5	3,532
Other taxes	**1,492**	40	1,068	43	746
Impairments	**1,774**	NM	216	88	115
Deepwater Horizon settlement and related costs	**3,930**	NM	15	NM	—

NM—not meaningful

For the year ended December 31, 2011, general and administrative (G&A) expense increased by $93 million primarily due to higher employee-related costs of $67 million primarily from operational expansions and changes in pension discount rates; higher legal, consulting, and other expenses of $51 million related to ongoing litigation and other matters; and increased insurance costs of $9 million related to higher industry-specific rates as a result of the Deepwater Horizon events. These increased costs are partially offset by a gain of $46 million from the financial settlement stemming from Tronox's rejection of the Master Separation Agreement (MSA) discussed in *Note 16—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. For the year ended December 31, 2010, G&A expense decreased due to lower bonus plan expense of $67 million, offset by higher legal and consulting fees of $41 million primarily due to costs associated with the Tronox bankruptcy, and higher employee-related costs.

For the year ended December 31, 2011, depreciation, depletion, and amortization (DD&A) expense increased by $116 million primarily attributable to higher sales volumes, partially offset by a lower average DD&A rate, largely the result of an $89 million DD&A expense that was taken in 2010 associated with depleted fields in the Gulf of Mexico. For the year ended December 31, 2010, DD&A increased $182 million primarily due to higher sales volumes and $89 million associated with the Gulf of Mexico, as discussed above, partially offset by a lower average DD&A rate attributable to reserve increases in the Marcellus shale and the Eagleford shale.

For the year ended December 31, 2011, other taxes increased by $424 million primarily due to higher crude-oil prices and total sales volumes, resulting in increased Algerian exceptional profits tax of $172 million, increased U.S. production and severance taxes of $152 million, and increased Chinese windfall profits tax of $55 million. Additionally, ad valorem taxes increased by $46 million in 2011 due to higher assessed property values. For the year ended December 31, 2010, other taxes increased $322 million primarily due to higher commodity prices and total sales volumes, resulting in increased Algerian exceptional profits tax of $129 million, increased U.S. production and severance taxes of $118 million, and increased Chinese windfall profits tax of $44 million. In addition, higher assessed property values increased ad valorem taxes by $30 million. Refer to *Note 17—Other Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information on the Algerian exceptional profits tax.

Impairment expense of $1.8 billion for the year ended December 31, 2011, included $1.2 billion related to oil and gas exploration and production reporting segment properties located in the United States, $458 million for midstream reporting segment properties, and $91 million related to the Company's investment in Venezuelan assets. Impairment expense of $952 million for U.S. onshore oil and gas properties and $446 million for associated midstream properties was triggered by lower natural-gas prices. Impairment expense also included $162 million related to reserves revisions for certain Gulf of Mexico properties, and $100 million related to onshore properties due to changes in projected cash flows, which resulted from the Company's intent to divest the properties. All of these assets were impaired to fair value. Further declines in commodity prices could result in additional price-related impairments. See *Risk Factors* under Item 1A of this Form 10-K for further discussion on the risks associated with oil, natural-gas, and NGLs prices. Impairment expense for the year ended December 31, 2010, included $145 million related to oil and gas exploration and production reporting segment properties located in the United States. The properties in the United States include $114 million related to a production platform included in the oil and gas exploration and production reporting segment that remains idle with no immediate plan for use, and for which a limited market exists. The platform was impaired to its estimated fair value of $25 million. Impairments for the year ended December 31, 2010, also included $61 million related to the Company's investment in Venezuelan assets that was impaired to its estimated fair value.

For the year ended December 31, 2011, Deepwater Horizon settlement and related costs included a $4.0 billion expense for the Company's cash payment made to BP pursuant to the Settlement Agreement, as well as $93 million of legal expenses and other related costs associated with the Deepwater Horizon events. These amounts were partially offset by a $163 million gain recognized in the fourth quarter for insurance recoveries associated with the Deepwater Horizon events. Legal expenses of $15 million related to the Deepwater Horizon events for 2010, previously recorded to general and administrative expense, were reclassified to Deepwater Horizon settlement and related costs. Although Anadarko has been indemnified by BP for certain costs, the Company may be required to recognize a liability for amounts in advance of or in connection with recognizing a receivable from BP for the related indemnity payment. In all circumstances, however, the Company expects that any additional indemnified liability that may be recognized by the Company will be subsequently recovered from BP itself or through the guarantees of BPCNA or BP p.l.c. Additionally, as part of the Settlement Agreement, BP has agreed that, to the extent it receives value in the future from claims that it has asserted or could assert against third parties arising from or relating to the Deepwater Horizon events, it will make cash payments (not to exceed $1.0 billion in the aggregate) to Anadarko, on a current and continuing basis, equal to 12.5% of the aggregate value received by BP in excess of $1.5 billion. Any payments received by the Company pursuant to this arrangement will be accounted for as a reimbursement of the $4.0 billion payment made to BP as part of the Settlement Agreement. Refer to *Note 2—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Other (Income) Expense

millions except percentages	**2011**	Inc/(Dec) vs. 2010	2010	Inc/(Dec) vs. 2009	2009
Interest Expense					
Current debt, long-term debt, and other	**$ 986**	13%	$ 871	13%	$ 773
(Gain) loss on early debt retirements and commitment termination	**—**	(100)	112	NM	(2)
Capitalized interest	**(147)**	(15)	(128)	(86)	(69)
Interest expense	**$ 839**	(2)	$ 855	22	$ 702

Anadarko's interest expense decreased for the year ended December 31, 2011, due to $19 million of increased capitalized interest related to higher construction-in-progress balances for long-term capital projects. Additionally, 2011 interest expense was lower due to items that occurred in 2010 with no similar expense in 2011, including $86 million associated with losses on early debt retirements, $17 million of commitment and structuring costs associated with a contemplated term-loan facility, and $9 million related to unamortized debt issuance costs recognized with the retirement of the Midstream Subsidiary Note Payable to a Related Party. These items were partially offset by $48 million from a higher average outstanding debt balance and weighted-average interest rate on outstanding debt, $29 million related to interest on capital lease obligations incurred in 2011, $24 million attributable to increased amortization of debt-issuance and credit-facility origination costs, and $20 million of higher fees on issued letters of credit and credit-facility commitment fees. Anadarko's interest expense increased for the year ended December 31, 2010, primarily due to the reversal of $78 million in 2009 for previously accrued interest expense related to the DWRRA dispute. In addition, $86 million of losses on early retirements of debt, $17 million of commitment and structuring costs, and $9 million of expensed unamortized debt issuance costs, discussed above, were incurred in 2010. The Company also incurred $12 million of amortized debt issuance costs associated with the $5.0 billion Facility. These increases were partially offset by increases in capitalized interest of $59 million due to higher construction-in-progress balances related to long-term capital projects. For additional information, see *Liquidity and Capital Resources—Uses of Cash—Debt Retirements and Repayments*, and *Interest-Rate Risk* under Item 7A of this Form 10-K.

millions except percentages	**2011**	Inc/(Dec) vs. 2010	2010	Inc/(Dec) vs. 2009	2009
(Gains) Losses on Commodity Derivatives, net					
Realized (gains) losses					
Natural gas	**$ (288)**	(44)%	$ (513)	85%	$ (277)
Oil and condensate	**61**	NM	15	(130)	(50)
Natural gas liquids	**1**	NM	—	—	—
Total realized (gains) losses	**(226)**	(55)	(498)	52	(327)
Unrealized (gains) losses					
Natural gas	**(192)**	(46)	(353)	180	444
Oil and condensate	**(140)**	NM	(42)	114	291
Natural gas liquids	**(4)**	NM	—	—	—
Total unrealized (gains) losses	**(336)**	(15)	(395)	154	735
Total (gains) losses on commodity derivatives, net	**$ (562)**	(37)	$ (893)	NM	$ 408

The Company enters into commodity derivatives to manage the risk of a decrease in the market prices for its anticipated sales of production. The change in (gains) losses on commodity derivatives, net includes the impact of derivatives entered into or settled and price changes related to positions open at December 31 of each year. For additional information on (gains) losses on commodity derivatives, see *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

millions except percentages	**2011**	Inc/(Dec) vs. 2010	2010	Inc/(Dec) vs. 2009	2009
(Gains) Losses on Other Derivatives, net					
Realized (gains) losses—interest-rate derivatives and other	**$ 59**	NM	$ —	(100)%	$ (525)
Unrealized (gains) losses—interest-rate derivatives and other	**964**	NM	285	NM	(57)
Total (gains) losses on other derivatives, net	**$ 1,023**	NM	$ 285	(149)	$ (582)

Anadarko enters into interest-rate swaps to fix or float interest rates on existing or anticipated indebtedness to manage exposure to interest-rate changes. In 2008 and 2009, Anadarko entered into interest-rate swap contracts as a fixed-rate payor to mitigate interest-rate risk associated with anticipated debt issuances. In 2009, the Company revised the swap contract terms to increase the weighted-average interest rate of the swap portfolio, and realized a $552 million gain. In 2011, the Company extended the swap maturity dates from October 2011 to June 2014 for interest-rate swaps with an aggregate notional principal amount of $1.85 billion. In connection with these extensions, the swap interest rates were also adjusted. In addition, interest-rate swap agreements with an aggregate notional principal amount of $150 million were settled for a loss of $57 million in October 2011. For additional information, see *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

millions except percentages	**2011**	Inc/(Dec) vs. 2010	2010	Inc/(Dec) vs. 2009	2009
Other (Income) Expense, net					
Interest income	**$ (21)**	62%	$ (13)	(32)%	$ (19)
Other	**275**	NM	(106)	NM	(24)
Total other (income) expense, net	**$ 254**	NM	$ (119)	177	$ (43)

Total other income decreased $373 million for the year ended December 31, 2011, primarily due to a $250 million Tronox-related contingent loss in 2011, the 2010 reversal of the $95 million reimbursement obligation to Tronox described below, and $20 million due to unfavorable exchange-rate changes applicable to foreign currency purchased in anticipation of funding future expenditures on major development projects and foreign currency held in escrow as of December 31, 2011, pending final determination of the Company's Brazilian tax liability from its 2008 divestiture of the Peregrino field offshore Brazil. The Brazilian tax matter is currently being considered by the Brazilian courts, and the Company expects this litigation to be resolved within the next 18 to 24 months. An unfavorable decision may require the Company to record an additional tax liability in its consolidated financial statements. See *Note 16—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information regarding Tronox litigation.

For 2010, total other income increased primarily due to the reversal of the $95 million reimbursement obligation to Tronox as a result of the cancellation of the MSA by Tronox that occurred as part of Tronox's bankruptcy proceedings. Under the terms of the MSA entered into between Kerr-McGee and Tronox, a former subsidiary of Kerr-McGee that held Kerr-McGee's chemical business, Kerr-McGee agreed to reimburse Tronox for 50% of certain qualifying environmental-remediation costs incurred and paid by Tronox and its subsidiaries before November 28, 2012, subject to certain limitations and conditions. The reimbursement obligation under the MSA was limited to a maximum aggregate reimbursement of $100 million. The reversal of this liability in 2010 was partially offset by $54 million of unfavorable changes in foreign-currency exchange rates primarily attributable to cash denominated in Brazilian currency held in escrow.

Income Tax Expense

millions except percentages	**2011**	2010	2009
Income tax expense (benefit)	**$ (856)**	$ 820	$ (5)
Effective tax rate	**25%**	50%	5%

The Company reported a loss before income taxes for the year ended December 31, 2011. As a result, items that ordinarily increase or decrease the tax rate will have the opposite effect. The decrease from the 35% U.S. federal statutory rate for the year ended December 31, 2011, was primarily attributable to the following:

- tax expense associated with the accrual of the Algerian exceptional profits tax, which is non-deductible for Algerian income tax purposes;
- U.S. tax on foreign income inclusions and distributions;
- foreign tax rate differential and valuation allowances; and
- items resulting from business acquisitions and other items.

These amounts were partially offset by the following:

- U.S. income tax benefits associated with foreign losses and the restructuring of foreign operations; and
- state income tax benefits.

The increase from the 35% U.S. federal statutory rate for the year ended December 31, 2010, was primarily attributable to the following:

- tax expense associated with the accrual of the Algerian exceptional profits tax;
- U.S. tax on foreign income inclusions and distributions;
- foreign tax rate differential and valuation allowances; and
- the unfavorable resolution of uncertain tax positions.

These amounts were partially offset by the following:

- U.S. income tax impact from losses and restructuring of foreign operations; and
- the federal manufacturing deduction and other items.

The decrease from the 35% U.S. federal statutory rate for the year ended December 31, 2009, was primarily attributable to the following:

- tax expense associated with the accrual of the Algerian exceptional profits tax;
- foreign tax rate differential and valuation allowances; and
- U.S. tax on foreign income inclusions and distributions.

These amounts were partially offset by the following:

- benefits associated with changes in uncertain tax positions;
- state income taxes, including a change in the state income tax rate expected to be in effect at the time the Company's deferred state income tax liability is expected to be settled or realized; and
- U.S. income tax impact from losses and restructuring of foreign operations and other items.

For additional information on income tax rates, see *Note 18—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Net Income Attributable to Noncontrolling Interests

For the years ended December 31, 2011, 2010, and 2009, the Company's net income attributable to noncontrolling interests of $81 million, $60 million, and $32 million, respectively, primarily related to the public ownership interests in Western Gas Partners, LP (WES), a consolidated subsidiary of the Company. Public ownership of WES was 54.7%, 51.5%, and 43.2% at year-end 2011, 2010, and 2009, respectively. See *Note 8—Noncontrolling Interests* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

OPERATING RESULTS

Segment Analysis—Adjusted EBITDAX To assess the performance of Anadarko's reporting segments, the chief operating decision maker analyzes income (loss) before income taxes, interest expense, exploration expense, DD&A, impairments, Deepwater Horizon settlement and related costs, and unrealized (gains) losses on derivatives, net, less net income attributable to noncontrolling interests (Adjusted EBITDAX). The Company's definition of Adjusted EBITDAX, which is not a GAAP measure, excludes interest expense to allow for assessment of segment operating results without regard to Anadarko's financing methods or capital structure. Adjusted EBITDAX also excludes exploration expense, as it is not an indicator of operating efficiency for a given reporting period. However, exploration expense is monitored by management as part of costs incurred in exploration and development activities. Similarly, DD&A and impairments are excluded from Adjusted EBITDAX as a measure of segment operating performance because capital expenditures are evaluated at the time capital costs are incurred. Anadarko's definition of Adjusted EBITDAX excludes Deepwater Horizon settlement and related costs as these costs are outside the normal operations of the Company. See *Note 2—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. Finally, unrealized (gains) losses on derivatives, net are excluded from Adjusted EBITDAX because unrealized (gains) losses on derivatives are not considered to be a measure of asset operating performance. Management believes that the presentation of Adjusted EBITDAX provides information useful in assessing the Company's financial condition and results of operations and that Adjusted EBITDAX is a widely accepted financial indicator of a company's ability to incur and service debt, fund capital expenditures, and make distributions to stockholders.

Adjusted EBITDAX, as defined by Anadarko, may not be comparable to similarly titled measures used by other companies. Therefore, Anadarko's consolidated Adjusted EBITDAX should be considered in conjunction with net income (loss) attributable to common stockholders and other performance measures prepared in accordance with GAAP, such as operating income or cash flows from operating activities. Adjusted EBITDAX has important limitations as an analytical tool because it excludes certain items that affect net income (loss) attributable to common stockholders and net cash provided by operating activities. Adjusted EBITDAX should not be considered in isolation or as a substitute for an analysis of Anadarko's results as reported under GAAP. Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) before income taxes, and consolidated Adjusted EBITDAX by reporting segment.

Adjusted EBITDAX

millions except percentages	**2011**	Inc/(Dec) vs. 2010	2010	Inc/(Dec) vs. 2009	2009
Income (loss) before income taxes	**$ (3,424)**	NM	$ 1,641	NM	$ (108)
Exploration expense	**1,076**	10%	974	(12)%	1,107
DD&A	**3,830**	3	3,714	5	3,532
Impairments	**1,774**	NM	216	88	115
Deepwater Horizon settlement and related costs(1)	**3,930**	NM	15	NM	—
Interest expense	**839**	(2)	855	22	702
Unrealized (gains) losses on derivative instruments, net(2)	**616**	NM	(114)	(116)	717
Less: Net income attributable to noncontrolling interests	**81**	35	60	88	32
Consolidated Adjusted EBITDAX	**$ 8,560**	18	$ 7,241	20	$ 6,033
Adjusted EBITDAX by segment					
Oil and gas exploration and production	**$ 8,787**	29	$ 6,786	23	$ 5,524
Midstream	**419**	36	308	17	263
Marketing	**(63)**	NM	4	104	(110)
Other and intersegment eliminations	**(583)**	NM	143	(60)	356

(1) In 2011, the Company revised the definition of Adjusted EBITDAX to exclude the Deepwater Horizon settlement and related costs. The prior periods have been adjusted to reflect this change.

(2) In 2010, the Company revised the definition of Adjusted EBITDAX to exclude the impact of unrealized (gains) losses on derivatives, net. The prior periods have been adjusted to reflect this change.

Oil and Gas Exploration and Production The increase in Adjusted EBITDAX for the year ended December 31, 2011, was primarily due to the higher crude-oil and NGLs prices and higher sales volumes. These increases were partially offset by lower natural-gas prices and increased operating expenses, primarily other taxes, which increased as a result of higher sales volumes and crude-oil prices. The increase in Adjusted EBITDAX for the year ended December 31, 2010, was primarily due to the impact of higher commodity prices and higher sales volumes, partially offset by the 2009 reversal of amounts previously accrued in connection with the DWRRA dispute.

Midstream The increase in Adjusted EBITDAX for the year ended December 31, 2011, resulted from increased margins due to higher NGLs prices and volumes, lower prices for natural-gas purchases, and margins provided by 2011 asset acquisitions. Also contributing to the increase was the recognition of a $21 million gain from the acquisition-date fair-value remeasurement of the Company's pre-acquisition 7% equity interest in the Wattenberg Plant. These increases were partially offset by losses related to midstream assets held for sale. For the year ended December 31, 2010, the increase in Adjusted EBITDAX resulted primarily from an increase in revenue due to higher prices and NGLs volumes, which impacted revenues earned under the Company's percent-of-proceeds and keep-whole contracts. These increases were reduced by higher cost of product related to NGLs purchases, which increased due to higher NGLs prices, and margins associated with assets divested in 2009.

Marketing Marketing earnings primarily represent the margin earned on sales of natural gas, oil, and NGLs purchased from third parties. The decrease in Adjusted EBITDAX for the year ended December 31, 2011, resulted primarily from lower margins associated with natural-gas sales from inventory and an increase in transportation expense related to new transportation agreements effective January 2011. The increase in Adjusted EBITDAX for the year ended December 31, 2010, was primarily due to higher margins associated with natural-gas sales from inventory, and lower transportation costs due to lower firm transportation amortization as a result of asset impairments in 2009.

Other and Intersegment Eliminations Other and intersegment eliminations consist primarily of corporate costs, realized gains and losses on derivatives, and income from hard minerals investments and royalties. The decrease in Adjusted EBITDAX for the year ended December 31, 2011, was primarily due to lower realized gains on commodity derivatives in 2011, realized losses on interest rate swaps in 2011, $250 million Tronox-related contingent loss in 2011, exchange-rate changes applicable to foreign currency, and the 2010 reversal of the remaining $95 million reimbursement obligation that was provided by Kerr-McGee to Tronox pursuant to the terms of the MSA. See *Note 16—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information. The decrease in Adjusted EBITDAX for the year ended December 31, 2010, was primarily due to realized gains on interest-rate swaps in 2009, partially offset by increased realized gains on commodity derivatives in 2010 and the reversal of the $95 million liability related to the reimbursement obligation discussed above.

Proved Reserves Anadarko is focused on growth and profitability, and reserves replacement is a key to growth. Future profitability partially depends on commodity prices and the cost of finding and developing oil and gas reserves. Reserves growth can be achieved through successful exploration and development drilling, improved recovery, or acquisition of producing properties.

Additional reserves information is contained in the *Supplemental Information on Oil and Gas Exploration and Production Activities (Supplemental Information)* under Item 8 of this Form 10-K.

MMBOE	**2011**	2010	2009
Proved Reserves			
Beginning of year	**2,422**	2,304	2,277
Reserves additions and revisions			
Discoveries and extensions	**174**	83	70
Infill-drilling additions(1)	**203**	312	125
Drilling-related reserves additions and revisions	**377**	395	195
Other non-price-related revisions(1)	**7**	(66)	87
Acquisition of proved reserves in place	**—**	1	32
Price-related revisions(1)	**8**	29	(39)
Total reserves additions and revisions	**392**	359	275
Sales in place	**(29)**	(6)	(24)
Production	**(246)**	(235)	(224)
End of year	**2,539**	2,422	2,304
Proved Developed Reserves			
Beginning of year	**1,673**	1,624	1,600
End of year	**1,811**	1,673	1,624

(1) Combined and reported as revisions of prior estimates in the Company's *Supplemental Information* under Item 8 of this Form 10-K.

Proved Reserve Additions and Revisions During 2011, the Company added 392 MMBOE of proved reserves as a result of additions (purchases in place, discoveries, and extensions) and revisions. The Company expects the majority of future reserves growth to come from revisions associated with infill drilling (reserves bookings related to infill wells are treated as positive revisions), extensions of current fields, new discoveries onshore United States and in the deep waters of the Gulf of Mexico, successful exploration in international growth areas, and purchases of properties in strategic areas.

Additions During 2011, Anadarko added 174 MMBOE of proved reserves primarily as a result of successful domestic drilling in the Marcellus and Eagleford shale areas and the Gulf of Mexico. Although shale plays represent only about 5% of the Company's total proved reserves, growth in the shale plays contributed 119 MMBOE of total additions. The Company had no material acquisitions of proved reserves in place in 2011. During 2010, Anadarko added 83 MMBOE of proved reserves primarily as a result of successful drilling in the United States. Shale plays represented about 2% of the Company's total proved reserves at year-end 2010, but contributed 45 MMBOE of additions. During 2009, Anadarko added 70 MMBOE of proved reserves primarily as a result of successful drilling. The Company also acquired 32 MMBOE of proved reserves in place related to onshore domestic assets in 2009.

Revisions Total revisions in 2011 were 218 MMBOE or 9% of the beginning-of-year reserves base. The revisions included an increase of 203 MMBOE related to the continuation of successful infill drilling in large onshore areas, including the Greater Natural Buttes, Wattenberg, and Pinedale fields, 182 MMBOE of positive revisions to prior estimates and 8 MMBOE associated with higher oil prices. These positive revisions were partially offset by the transfer of 175 MMBOE of proved reserves to unproved categories primarily as a result of changes to development plans and economic conditions experienced during 2011. Total revisions in 2010 were 275 MMBOE or 12% of the beginning-of-year reserves base. The revisions included an increase of 312 MMBOE related to successful infill drilling in large onshore areas, 77 MMBOE of revisions to prior estimates, and 29 MMBOE associated with higher oil and gas prices. These positive revisions were partially offset by the transfer of 143 MMBOE of PUDs to unproved categories as a result of changes to development plans during 2010. Total revisions in 2009 were 173 MMBOE or 8% of the beginning-of-year reserves base. The revisions included an increase of 125 MMBOE related to successful infill drilling in large onshore areas and 87 MMBOE of revisions to prior estimates. The 2009 revisions also included a decrease of 39 MMBOE caused by lower natural-gas prices.

Sales in Place In 2011, the Company sold U.S. properties containing 7 MMBOE of proved developed reserves and 22 MMBOE of proved undeveloped reserves. This included a sale of working interest in the Maverick basin as well as sales of assets in South Texas and Alaska. In 2010, the Company sold properties located in the United States and Egypt that held 5 MMBOE of proved developed reserves and 1 MMBOE of proved undeveloped reserves. In 2009, the Company sold properties located primarily in the Rockies, which accounted for 14 MMBOE of developed properties and 10 MMBOE of undeveloped properties.

Discounted Future Net Cash Flows At December 31, 2011, the discounted estimated future net cash flows (at 10%) from Anadarko's proved reserves was $26.5 billion (measured in accordance with the regulations of the Securities and Exchange Commission (SEC) and the Financial Accounting Standards Board (FASB)). This amount was calculated based on the 12-month average beginning-of-month prices for the year, held flat for the life of the reserves, adjusted for any contractual provisions. The increase of $5.0 billion or 23% in 2011 compared to 2010 is primarily due to an increase in liquids prices and positive revisions of previous reserves estimates. See *Supplemental Information* under Item 8 of this Form 10-K.

The present value of future net cash flows does not purport to be an estimate of the fair value of Anadarko's proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money and the risks inherent in producing oil and natural gas.

LIQUIDITY AND CAPITAL RESOURCES

Overview Anadarko generates cash needed to fund capital expenditures, debt-service obligations, and dividend payments primarily from operating activities, and enters into debt and equity transactions to maintain the desired capital structure and finance acquisition opportunities. Liquidity may also be enhanced through asset divestitures and joint ventures that reduce future capital expenditures.

Consistent with this approach, cash flows from operating activities were the primary source for capital investment funding during 2011. The Company continuously monitors its liquidity needs, coordinates its capital expenditure program with its expected cash flows and projected debt-repayment schedule, and evaluates available funding alternatives in light of current and expected conditions.

At December 31, 2011, the Company had outstanding borrowings of $2.5 billion at a rate of 1.79% under the $5.0 billion Facility. These borrowings were used to fund a portion of the Company's $4.0 billion payment to BP pursuant to the Settlement Agreement. The Company plans to repay these borrowings with a portion of the proceeds from the monetization of certain assets, potentially including onshore domestic properties, Indonesian properties, and its Brazilian subsidiary.

At December 31, 2011, Anadarko's scheduled 2012 debt maturities were $170 million. In addition, the Zero-Coupon Senior Notes due 2036 (Zero Coupons) can be put to the Company in October 2012, as discussed below. The Company has a variety of funding sources available to satisfy these obligations, including cash on hand, an asset portfolio that provides ongoing cash-flow-generating capacity, opportunities for liquidity enhancement through divestitures and joint-venture arrangements, and remaining available capacity under the $5.0 billion Facility. Management believes that the Company's liquidity position, asset portfolio, and continued strong operating and financial performance provide the necessary financial flexibility to fund current operations.

Revolving Credit Facility Borrowings under the $5.0 billion Facility bear interest, at the Company's election, at (i) the London Interbank Offered Rate (LIBOR) plus a margin ranging from 1.25% to 2.50%, based on the Company's credit rating, or (ii) the greatest of (a) the JPMorgan Chase Bank, N.A. prime rate, (b) the Federal Funds Effective Rate plus 0.50%, or (c) one-month LIBOR plus 1%, plus in each case, an applicable margin ranging from 0.25% to 1.50%.

Obligations incurred under the $5.0 billion Facility, as well as obligations Anadarko has to lenders or their affiliates pursuant to certain derivative instruments as discussed in *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K, are guaranteed by certain of the Company's wholly owned domestic subsidiaries, and are secured by a perfected first-priority security interest in certain exploration and production assets located in the United States and 65% of the capital stock of certain wholly owned foreign subsidiaries. The Company had available borrowing capacity of $2.1 billion at year-end 2011 ($5.0 billion maximum capacity, less $2.5 billion of outstanding borrowings and $400 million of letter-of-credit capacity maintained pursuant to the terms of the LOC Facility discussed below).

During 2011, the Company entered into the LOC Facility. Compensating balances deposited with the financial institution provide for reduced fees under the LOC Facility. These compensating balances may be withdrawn at any time, resulting in higher fees. Cash and cash equivalents includes $328 million of demand deposits serving as compensating balances for outstanding letters of credit at December 31, 2011. The LOC Facility requires the Company to maintain a senior debt revolving credit facility with minimum commitments of at least $1.0 billion and the availability to issue letters of credit of at least $400 million.

Financial Covenants The $5.0 billion Facility contains various customary covenants with which Anadarko must comply, including, but not limited to, limitations on incurrence of indebtedness, liens on assets, and asset sales. Anadarko is also required to maintain, at the end of each quarter, (i) a Consolidated Leverage Ratio of no more than 4.5 to 1.0 (relative to Consolidated EBITDAX for the most recent period of four calendar quarters), (ii) a ratio of Current Assets to Current Liabilities of no less than 1.0 to 1.0, and (iii) a Collateral Coverage Ratio of no less than 1.75 to 1.0, in each case, as defined in the $5.0 billion Facility. The Collateral Coverage Ratio is the ratio of an annually redetermined value of pledged assets to outstanding loans under the $5.0 billion Facility. Additionally, to borrow from the $5.0 billion Facility, the Collateral Coverage Ratio must be no less than 1.75 to 1.0 after giving pro forma effect to the requested borrowing. At December 31, 2011, the Company was in compliance with all applicable covenants, and there were no restrictions on its ability to utilize the available capacity of the $5.0 billion Facility.

The covenants contained in certain of the Company's credit agreements provide for a maximum debt-to-capitalization ratio of 67%. The covenants do not specifically restrict the payment of dividends; however, the impact of dividends paid on the Company's debt-to-capitalization ratio must be considered in order to ensure covenant compliance. At December 31, 2011, Anadarko was in compliance with all financial covenants.

Zero-Coupon Notes In a 2006 private offering, Anadarko received $500 million of loan proceeds upon issuing the Zero Coupons. The Zero Coupons mature in October 2036 and have an aggregate principal amount due at maturity of $2.4 billion, reflecting a yield to maturity of 5.24%. The holder has the right to cause the Company to repay the then-accreted value of the outstanding Zero Coupons in October of each year starting in 2012. The accreted value of the outstanding Zero Coupons was $640 million at December 31, 2011, and will be $682 million in October 2012.

The Company considers its cash-flow-generating capacity and access to additional liquidity sufficient to continue to satisfy the Company's debt-service and other obligations, including the potential early repayment of the outstanding Zero Coupons.

WES Funding Sources WES, a consolidated subsidiary of the Company, primarily uses cash flows from operations to fund ongoing operations (including capital investments in the ordinary course of business), service its debt, and make distributions to its equity holders. As needed, WES supplements cash generated from its operating activities with proceeds from debt or equity issuances or borrowings under its five-year, $800 million senior unsecured revolving credit facility maturing in March 2016 (RCF).

During 2011, WES entered into its RCF which amended and restated its $450 million senior unsecured revolving credit facility. Borrowings under the RCF bear interest at (i) LIBOR plus an applicable margin ranging from 1.30% to 1.90%, or (ii) the greatest of (a) the Wells Fargo Bank, National Association prime rate, (b) the Federal Funds Effective Rate plus 0.50%, or (c) one-month LIBOR plus 1%, plus in each case, an applicable margin ranging from 0.30% to 0.90%. At December 31, 2011, WES was in compliance with all covenants contained in the RCF, had no outstanding borrowings under the RCF, and had the entire $800 million of RCF borrowing capacity available. See *Financing Activities* below.

Insurance Coverage and Other Indemnities Anadarko maintains property and casualty insurance that includes coverage for physical damage to the Company's properties, blowout/control of a well, restoration and redrill, sudden and accidental pollution, third-party liability, workers' compensation and employers' liability, and other risks. Anadarko's insurance coverage includes deductibles that must be met prior to recovery. Additionally, the Company's insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect the Company against liability or loss from all potential consequences and damages.

The Company's current insurance coverage, which was obtained subsequent to the Deepwater Horizon events, includes physical damage to Anadarko's properties on a replacement cost basis; $750 million for an offshore blowout/control of a well, restoration and redrill, and pollution from an offshore blowout ($75 million for onshore); $275 million for aircraft liability; and $675 million for third-party liabilities (including sudden and accidental pollution). The Company's total limit is approximately $1.425 billion (which is reduced proportionally to the Company's participating interest in a venture except for the $750 million portion dealing with an offshore blowout, which does not reduce below a 50% participating interest subject to certain reporting requirements) for the negative environmental impacts of an offshore blowout. There is currently no coverage for loss of production income from any facilities or for physical damage to the Company's properties, blowout/control of a well, or restoration and redrill to the extent these items result from the effects of a named windstorm.

Anadarko's property and casualty insurance policies renew in June of each year, with the next renewals scheduled for June 2012. At that time, the Company may not be able to secure similar coverage for the same costs, if at all. Future insurance coverage costs for the oil and gas industry could increase and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that the Company considers economically acceptable.

The Company's service agreements, including drilling contracts, generally indemnify Anadarko for injuries and death to employees of the service provider and subcontractors hired by the service provider as well as for property damage suffered by the service provider and its contractors. Also, these service agreements generally indemnify Anadarko for pollution originating from the equipment of any contractors or subcontractors hired by the service provider.

Following is a discussion of significant sources and uses of cash flows for the three-year period ended December 31, 2011. Forward-looking information related to the Company's liquidity and capital resources is discussed in *Outlook* that follows.

Sources of Cash

Operating Activities Anadarko's cash flows from operating activities in 2011 was $2.5 billion compared to $5.2 billion in 2010 and $3.9 billion in 2009. Cash flows for 2011 decreased primarily due to the $4.0 billion payment to BP related to the Settlement Agreement. Also contributing to the decline were lower natural-gas prices, increased operating expenses primarily due to other taxes (which increased as a result of higher sales volumes and commodity prices), and the impact of changes in working capital items. These decreases were partially offset by higher crude-oil and NGLs prices and higher sales volumes. Cash flows for 2010 increased primarily due to higher commodity prices, higher sales volumes, and the impact of changes in working capital items.

One of the primary sources of variability in the Company's cash flows from operating activities is fluctuation in commodity prices, which Anadarko partially mitigates by entering into commodity derivatives. Sales-volume changes also impact cash flow, but have not been as volatile as commodity prices. Anadarko's long-term cash flows from operating activities is dependent on commodity prices, sales volumes, costs required for continued operations, and debt service.

Investing Activities During 2011, 2010, and 2009, Anadarko received proceeds of $555 million, $70 million, and $176 million before income taxes, respectively, related to several property divestiture transactions.

Financing Activities During 2011, Anadarko borrowed $2.5 billion at a rate of 1.79% under the $5.0 billion Facility to fund a portion of the $4.0 billion payment to BP associated with the Settlement Agreement (see *Deepwater Horizon Settlement Costs* below). In 2011, WES, a consolidated subsidiary of Anadarko, borrowed $320 million under its RCF primarily to fund a third-party asset acquisition and $250 million under its RCF to repay the senior unsecured term loan (Term Loan) as discussed in *Uses of Cash*. Also, during 2011, WES issued approximately 10 million common units to the public, raising net proceeds of $328 million, which was used to repay outstanding RCF borrowings and for other general partnership purposes. In addition, during 2011, WES completed a public offering of $500 million aggregate principal amount of 5.375% Senior Notes due 2021, with net proceeds from the offering used to repay amounts then outstanding under its RCF.

During 2010, the Company received net proceeds of $2.7 billion related to the issuance of $2.8 billion in aggregate principal amount of senior notes and used the net proceeds, combined with cash on hand, to redeem $3.0 billion aggregate principal amount of 2011 and 2012 debt maturities. See *Uses of Cash* for further information about debt repayments.

In connection with entering into the $5.0 billion Facility in 2010 the Company paid upfront underwriting, structuring, arrangement, and other costs totaling $172 million.

During 2010, WES borrowed a total of $670 million under its Term Loan and RCF primarily to fund the acquisition of certain midstream assets from Anadarko. WES also issued approximately 13 million common units in two 2010 public offerings, realizing net proceeds of $338 million, which were used to repay a portion of outstanding RCF borrowings.

During 2009, Anadarko raised $2.0 billion in connection with the public offering of senior notes and an additional $1.3 billion in connection with the public offering of 30 million shares of common stock. Proceeds from the offerings were used to fund the retirement of outstanding Floating Rate Notes and for general corporate purposes.

Uses of Cash

Anadarko invests significant capital to acquire, explore, and develop oil and natural-gas resources and midstream infrastructure, in addition to funding ongoing operating costs, including interest cost and taxes, making debt repayments, and paying dividends to its shareholders.

Capital Expenditures The following table presents the Company's capital expenditures by category.

millions	**2011**	2010	2009
Property Acquisitions			
Exploration	**$ 647**	$ 519	$ 279
Development	**—**	22	266
Exploration	**1,469**	1,278	1,229
Development	**3,525**	3,267	2,886
Total oil and gas costs incurred(1)	**5,641**	5,086	4,660
Less: Corporate acquisitions and non-cash property exchanges	**(17)**	(37)	(284)
Less: Asset retirement costs	**(148)**	(86)	(63)
Less: Geological and geophysical, exploration overhead, delay rentals expenses, and other expenses	**(450)**	(291)	(312)
Total oil and gas capital expenditures	**5,026**	4,672	4,001
Gathering, processing, and marketing and other(2)	**1,527**	497	557
Total capital expenditures(1)	**$ 6,553**	$ 5,169	$ 4,558

(1) Oil and gas costs incurred represent costs related to finding and developing oil and gas reserves. Capital expenditures represent additions to property and equipment excluding corporate acquisitions, property exchanges, and asset retirement costs. Capital expenditures and costs incurred are presented on an accrual basis. Additions to properties and equipment and dry hole costs on the Consolidated Statements of Cash Flows include certain adjustments that give effect to the timing of actual cash payments in order to provide a cash-basis presentation.

(2) Includes WES capital expenditures of $439 million, $81 million, and $32 million for 2011, 2010, and 2009, respectively.

The Company's capital spending increased 27% for the year ended December 31, 2011. Anadarko increased its ownership interest in the Wattenberg Plant to 100% by acquiring an additional 93% interest for $576 million in May 2011. Also, during the first quarter of 2011, WES acquired Platte Valley from a third party for $302 million. These acquisitions, along with future expansion plans, align Anadarko's natural-gas processing capacity with the Company's anticipated production growth in the Rockies. In addition, these acquisitions position the Company to improve field recoveries and realize operational cost efficiencies. The increase to capital expenditures was also due to increased development drilling costs of $258 million primarily related to onshore U.S. properties and higher exploration expenditures of $191 million primarily resulting from exploration drilling in Ghana.

Anadarko's capital spending increased 13% for the year ended December 31, 2010, primarily due to an increase in exploration lease acquisitions onshore and offshore United States, higher development drilling onshore, and increased expenditures related to construction in Algeria. In early 2009, the Company began focusing its capital investments toward areas of the Company's portfolio that have a higher liquids component and infrastructure advantages that enable Anadarko to extract higher-value liquids and access premium markets.

See *Outlook* below for information regarding sources of cash used to fund capital expenditures for 2012.

Deepwater Horizon Settlement Costs In October 2011, the Company and BP entered into the Settlement Agreement related to the Deepwater Horizon events. The Company paid $4.0 billion and transferred its interest in the Macondo well and Lease to BP. Refer to *Note 2—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Pension Contributions During the year ended December 31, 2011, the Company made contributions of \$301 million to its funded pension plans, \$10 million to its unfunded pension plans, and \$17 million to its unfunded other postretirement benefit plans. The increase in contributions to the funded pension plans during 2011 resulted from lower discount rates compared to the prior measurement period, which increased the pension liability and the corresponding funding target.

Debt Retirements and Repayments During 2011, WES repaid \$619 million of borrowings under its RCF and a \$250 million Term Loan primarily from proceeds from public debt and equity offerings, as discussed in *Sources of Cash*. In addition, the Company repaid \$285 million principal amount of 6.875% Senior Notes that matured in September 2011.

In 2010, the Company used \$1.6 billion to repay the Midstream Subsidiary Note and \$1.5 billion, including \$86 million for early-tender premiums, to redeem senior notes scheduled to mature in 2011 and 2012. The repayments were funded with proceeds from new borrowings, as well as cash on hand. Also in 2010, WES repaid \$371 million outstanding under its RCF primarily from proceeds related to its public offerings discussed in *Sources of Cash*.

In 2009, using a portion of proceeds from new debt issuances, the Company repaid an aggregate principal amount of \$1.6 billion of debt, including \$1.4 billion in aggregate principal amount of Floating-Rate Notes due in 2009.

For additional information on the Company's debt instruments, such as transactions during the period, years of maturity, and interest rates, see *Note 12—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Common Stock Dividends and Distributions to Noncontrolling WES Interest Owners In 2011, 2010, and 2009, Anadarko paid \$181 million, \$180 million, and \$176 million, respectively, in dividends to its common stockholders (nine cents per share per quarter). Anadarko has paid a dividend to its common stockholders quarterly since becoming an independent public company in 1986. The amount of future dividends paid to Anadarko common stockholders will be determined by the Board of Directors on a quarterly basis and will depend on earnings, financial conditions, capital requirements, the effect a dividend payment would have on the Company's compliance with relevant financial covenants, and other factors.

Anadarko's consolidated subsidiary, WES, distributed to its unitholders, other than Anadarko, an aggregate of \$72 million, \$42 million, and \$26 million during 2011, 2010, and 2009, respectively. WES has made quarterly distributions to its unitholders since its initial public offering in the second quarter of 2008 and has increased its distribution from \$0.30 per common unit for the third quarter of 2008 to \$0.44 per common unit for the fourth quarter of 2011.

Other During 2011, the Company and its partners in the Jubilee project in Ghana purchased the FPSO. The Company's cash contribution was \$108 million.

Outlook

Anadarko believes that its cash on hand and expected level of operating cash flows will be sufficient to fund the Company's projected operational and capital programs for 2012, while continuing to meet its other obligations. The Company's cash on hand is available for use. If capital expenditures exceed operating cash flows and cash on hand, additional funding would likely be supplemented as needed through borrowings under the $5.0 billion Facility, which provides available borrowing capacity of $2.1 billion ($5.0 billion maximum capacity, less $2.5 billion of outstanding borrowings and $400 million of letter-of-credit capacity maintained pursuant to the terms of the LOC Facility). The Company currently does not consider European sovereign debt events to pose significant risk to the Company's ability to access available borrowing capacity under the $5.0 billion Facility. The Company may also enter into joint-venture arrangements and asset divestitures to supplement cash flow. The Company is marketing certain onshore domestic properties, Indonesian properties, and its Brazilian subsidiary, in order to redirect its operating activities and capital investment to other areas and to repay borrowings under the $5.0 billion Facility.

The Company continuously monitors its liquidity needs, coordinates its capital expenditure program with its expected cash flows and projected debt-repayment schedule, and evaluates available funding alternatives in light of current and expected conditions. In order to increase the predictability of 2012 cash flows, Anadarko entered into strategic derivative positions, which cover a portion of its anticipated natural-gas and crude-oil sales volumes for 2012 and 2013. For details of derivative positions at December 31, 2011, see *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. In 2012, the Company entered into fixed-price swaps consisting of 60 MBbls/d at an average price of $107.20. The Company also entered into three-way collars for 45 MBbls/d, consisting of a sold call at $126, a purchased put at $105, and a sold put at $85, and for 15 MBbls/d, consisting of a sold call at $115, a purchased put at $95, and a sold put at $75.

After the Company entered into the Settlement Agreement with BP in October 2011, the various credit rating agencies each reviewed the credit ratings assigned to Anadarko. Moody's Investors Services placed the Company's senior unsecured credit rating under review for upgrade. Standard & Poor's affirmed its rating and revised its outlook from negative to stable. Fitch Ratings made no change to its rating or outlook. Any changes to the Company's credit ratings could affect the Company's requirement to provide financial assurance of its performance under certain contractual arrangements and derivative agreements, as well as the Company's cost of future borrowing and ability to access capital markets.

In the first quarter of 2011, the Company entered into a joint-venture agreement that requires a third-party partner to fund approximately $1.6 billion of Anadarko's future capital costs in the Eagleford shale, located in southwest Texas, in exchange for a one-third interest in Anadarko's Eagleford shale assets. The funding began in the second quarter of 2011 and covered $500 million of the Company's 2011 development costs. The funding covers 90% of Anadarko's development costs in subsequent years up to a $650 million annual limit. Based on expected activity, the third-party funding is expected to be fully utilized in the second half of 2013. At December 31, 2011, the Company had received $500 million of the total $1.6 billion funding obligation.

In the first quarter of 2010, the Company entered into a joint-venture agreement whereby a third-party partner agreed to fund up to $1.5 billion of Anadarko's share of future acquisition, drilling, completion, equipment, and other capital expenditures to earn a 32.5% interest in Anadarko's Marcellus shale assets, primarily located in north-central Pennsylvania. At December 31, 2011, the Company had received $1.0 billion of the total $1.5 billion funding obligation.

Off-Balance Sheet Arrangements

Anadarko may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. The Company's material off-balance sheet arrangements and transactions include operating lease arrangements and undrawn letters of credit. There are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect Anadarko's liquidity or availability of or requirements for capital resources. See *Obligations and Commitments* for more information regarding off-balance sheet arrangements.

Obligations and Commitments

The following is a summary of the Company's obligations at December 31, 2011.

	Obligations by Period				
millions	2012	2013-2014	2015-2016	2017 and beyond	Total
Total debt					
Principal—current borrowings	$ 170	$ —	$ —	$ —	$ 170
Principal—long-term borrowings[(1)]	—	775	4,250	11,757	16,782
Investee entities' debt[(2)]	—	—	—	2,853	2,853
Interest on borrowings	877	1,722	1,569	8,118	12,286
Investee entities' interest[(2)]	46	158	258	4,123	4,585
Operating leases					
Drilling rig commitments	573	943	829	599	2,944
Production platforms	46	106	80	168	400
Other	77	104	52	45	278
Asset retirement obligations	32	526	90	1,120	1,768
Midstream and marketing activities	393	840	783	1,547	3,563
Oil and gas activities	1,172	916	550	551	3,189
Derivative liabilities[(3)]	421	826	2	—	1,249
Uncertain tax positions, interest, and penalties[(4)]	18	21	10	—	49
Environmental liabilities	20	8	3	61	92
Total[(5)]	$ 3,845	$ 6,945	$ 8,476	$ 30,942	$ 50,208

(1) Represents the fully accreted principal amount of the Zero Coupons of $2.4 billion as coming due after 2016. While the Zero Coupons do not mature until 2036, the holder has the right to put the outstanding Zero Coupons to the Company each October beginning in 2012 at the then-accreted value. The Company could be required to repurchase the outstanding Zero Coupons at $682 million in October 2012.

(2) Anadarko has legal right of setoff and intends to net-settle its obligations under each of the notes payable to the investees with the distributable value of its interest in the corresponding investee. Accordingly, the investments and the obligations are presented net on the Consolidated Balance Sheets in other long-term liabilities—other for all periods presented. These notes payable provide for a variable rate of interest, reset quarterly. Therefore, future interest payments presented in the table above are estimated using the forward LIBOR rate curve. Further, the above table does not reflect the preferred return that Anadarko receives on its investment in these entities, which is also LIBOR-based, with a lower margin than the margin on the associated notes payable. See *Note 9—Investments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(3) Represents Anadarko's gross derivative liability after taking into account the impacts of netting margin and collateral balances deposited with counterparties. See *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(4) See *Note 18—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(5) This table does not include the Company's pension or postretirement benefit obligations. See *Note 21—Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Operating Leases Operating lease obligations include approximately $2.7 billion related to six offshore drilling vessels and $217 million related to certain contracts for onshore U.S. drilling rigs. Anadarko continues to manage its access to rigs in order to execute its drilling strategy over the next several years. Lease payments associated with successful exploratory wells and development wells, net of amounts billed to partners, are capitalized as a component of oil and gas properties. See *Note 16—Contingencies—Deepwater Drilling Moratorium and Other Related Matters* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information on drilling rigs.

The Company had $678 million in commitments under non-cancelable operating lease agreements for production platforms and equipment, buildings, facilities, compressors, and aircraft.

For additional information, see *Note 15—Commitments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Asset Retirement Obligations Anadarko is obligated to fund the costs of disposing of long-lived assets upon their abandonment. The majority of Anadarko's asset retirement obligations (AROs) relate to the plugging of wells and the related abandonment of oil and gas properties. The Company's AROs are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company's credit-adjusted risk-free interest rate. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment.

Midstream and Marketing Activities Anadarko has entered into various transportation, storage, and purchase agreements in order to access markets and provide flexibility for the sale of its natural gas, crude oil, and NGLs in certain areas.

Oil and Gas Activities Anadarko has various long-term contractual commitments pertaining to exploration, development, and production activities that extend beyond 2011. The Company has work-related commitments for, among other things, drilling wells, obtaining and processing seismic, and fulfilling rig commitments. The preceding table includes long-term drilling and work-related commitments of $3.2 billion, comprised of $2.7 billion related to the United States and $500 million related to international locations.

Environmental Liabilities Anadarko is subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. At December 31, 2011, the Company's balance sheet included a $92 million liability for remediation and reclamation obligations, most of which relate to companies acquired by Anadarko. The Company continually monitors the liability recorded and the remediation and reclamation process, and believes the amount recorded is appropriate. For additional information on environmental issues, see *Risk Factors* under Item 1A of this Form 10-K.

For additional information on contracts, obligations, and arrangements the Company enters into from time to time, see *Note 10—Derivative Instruments, Note 12—Debt and Interest Expense, Note 15—Commitments,* and *Note 16—Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

CRITICAL ACCOUNTING ESTIMATES

In preparing financial statements in accordance with GAAP in the United States, management makes informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Management evaluates its estimates and related assumptions regularly, including those related to the value of properties and equipment; proved reserves; goodwill; intangible assets; asset retirement obligations; litigation reserves; environmental liabilities; pension assets, liabilities, and costs; income taxes; and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates. Management considers the following to be its most critical accounting estimates that involve judgment. The selection and development of these estimates is discussed with the Company's Audit Committee.

Oil and Gas Activities

Anadarko applies the successful efforts method of accounting to account for its oil and gas activities. Under this method, acquisition costs and the costs associated with drilling exploratory wells are capitalized pending the determination of proved oil and gas reserves. Exploration geological and geophysical costs and other costs of carrying properties such as delay rentals are expensed as incurred.

Acquisition Costs

Acquisition costs of unproved properties are periodically assessed for impairment and are transferred to proved oil and gas properties to the extent the costs are associated with successful exploration activities.

Significant undeveloped leases are assessed individually for impairment, based on the Company's current exploration plans, and a valuation allowance is provided if impairment is indicated. Significant undeveloped leasehold costs are assessed for impairment at a lease level or resource play (for example, the Greater Natural Buttes area in the Rockies), while leasehold acquisition costs associated with prospective areas that have limited or no previous exploratory drilling are generally assessed for impairment by major prospect area. Unproved oil and gas properties with individually insignificant lease acquisition costs are amortized on a group basis (thereby establishing a valuation allowance) over the average lease term at rates that provide for full amortization of unsuccessful leases upon lease expiration or abandonment. Costs of expired or abandoned leases are charged against the valuation allowance, while costs of productive leases are transferred to proved oil and gas properties. Costs of maintaining and retaining unproved properties, as well as amortization of individually insignificant leases and impairment of unsuccessful leases, are included in exploration expense.

A majority of the Company's unproved property costs are associated with properties acquired in the Kerr-McGee and Western acquisitions in 2006 and to which proved developed producing reserves are also attributed. Generally, economic recovery of unproved reserves in such areas is not yet supported by actual production or conclusive formation tests, but may be confirmed by the Company's continuing exploration and development programs.

Another portion of the Company's unproved property costs are associated with the Land Grant acreage, where the Company owns mineral interests in perpetuity and plans to continue to explore and evaluate the acreage.

A change in the Company's expected future plans for exploration and development could cause an impairment of the Company's unproved property.

Exploratory Costs

Under the successful efforts method of accounting, exploratory costs associated with a well discovering hydrocarbons are initially capitalized, or suspended, pending determination of whether proved reserves can be attributed to the area as a result of drilling. At the end of each quarter, management reviews the status of all suspended exploratory drilling costs in light of ongoing exploration activities, which includes, for example, analyzing whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, analyzing whether development negotiations are underway or proceeding as planned. If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory drilling costs are expensed in that period. Therefore, at any point in time, the Company may have capitalized costs on its Consolidated Balance Sheets associated with exploratory wells that may be charged to exploration expense in a future period.

Proved Reserves

Anadarko estimates its proved oil and gas reserves as defined by the SEC and the FASB. This definition includes crude oil, natural gas, and NGLs that geological and engineering data demonstrate with reasonable certainty to be economically producible in future periods from known reservoirs under existing economic conditions, operating methods, government regulations, etc., i.e., at prices and costs as of the date the estimates are made. Prices include consideration of price changes provided only by contractual arrangements, and do not include adjustments based upon expected future conditions.

The Company's estimates of proved reserves are made using available geological and reservoir data, as well as production performance data. These estimates are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in, among other things, reservoir performance, prices, economic conditions, and governmental restrictions, as well as changes in the expected recovery associated with infill drilling. Decreases in prices, for example, may cause a reduction in some proved reserves due to reaching economic limits earlier. A material adverse change in the estimated volumes of proved reserves could have a negative impact on DD&A and could result in property impairments.

Fair Value

The Company estimates fair value for derivatives, long-lived assets for impairment testing, reporting units for goodwill impairment testing, assets and liabilities acquired in a business combination or exchanged in non-monetary transactions, guarantees, pension plan assets, initial measurements of AROs, and financial instruments that require fair-value disclosure, including cash and cash equivalents, accounts receivable, accounts payable and debt. When the Company is required to measure fair value and there is not a market-observable price for the asset or liability or a market-observable price for a similar asset or liability, the Company utilizes the cost, income, or market valuation approach depending on the quality of information available to support management's assumptions. The cost approach is based on management's best estimate of the current asset replacement cost. The income approach is based upon management's best assumptions regarding expectations of projected cash flows, and discounts the expected cash flows using a commensurate risk-adjusted discount rate. The market approach is based on management's best assumptions regarding prices and other relevant information from market transactions involving comparable assets. Such evaluations involve significant judgment and the results are based on expected future events or conditions, such as sales prices, estimates of future oil and gas production or throughput, development and operating costs and the timing thereof, future net cash flows, economic and regulatory climates, and other factors, most of which are often outside of management's control. However, assumptions used reflect a market participant's view of long-term prices, costs, and other factors, and are consistent with assumptions used in the Company's business plans and investment decisions.

Business Combinations

Accounting for the acquisition of a business requires the assets and liabilities of the acquired business to be recorded at fair value. Deferred taxes are recorded for any differences between asset and liability fair value and the tax basis of acquired assets and liabilities. Any excess of the purchase price over the amounts assigned to the identifiable assets and liabilities is recorded as goodwill.

Goodwill

At December 31, 2011, the Company had $5.6 billion of goodwill, including $335 million as a result of the Wattenberg Plant acquisition. See *Note 3—Acquisitions* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for further discussion of the Wattenberg Plant acquisition. The Company tests goodwill for impairment annually at October 1, or more often as facts and circumstances warrant. The first step in assessing whether an impairment of goodwill is necessary is to compare the fair value of the reporting unit to which goodwill is assigned to the carrying amount of the associated net assets and goodwill. A reporting unit is an operating segment or a component that is one level below an operating segment.

Because quoted market prices for the Company's reporting units are not available, management must apply judgment in determining the estimated fair value of reporting units for purposes of performing goodwill impairment tests. Management uses all available information to make these fair-value estimates, including the present values of expected future cash flows using discount rates commensurate with the risks associated with the assets and observed for the oil and gas exploration and production reporting unit, and market multiples of earnings before interest, taxes, depreciation, and amortization (EBITDA) for the gathering and processing and transportation reporting units.

In estimating the fair value of its oil and gas reporting unit, the Company assumes production profiles utilized in its estimation of reserves that are disclosed in the Company's supplemental oil and gas disclosures, market prices based on the forward price curve for oil and gas at the test date (adjusted for location and quality differentials), capital and operating costs consistent with pricing and expected inflation rates, and discount rates that management believes a market participant would utilize based upon the risks inherent in Anadarko's operations.

For the Company's other gathering and processing, WES gathering and processing, and transportation reporting units, the Company estimates fair value by applying an estimated multiple to projected 2012 EBITDA. The Company considered observable transactions in the market and trading multiples for peers in determining an appropriate multiple to apply against the Company's projected EBITDA for these reporting units.

A lower fair-value estimate in the future for any of these reporting units could result in impairment of goodwill. Factors that could trigger a lower fair-value estimate include sustained price declines, cost increases, regulatory or political environment changes, and other changes in market conditions such as decreased prices in market-based transactions for similar assets, as well as difficulty or potential delays in obtaining drilling permits or other unanticipated events. Based on the most recent goodwill impairment tests, the Company concluded that the fair value of each reporting unit substantially exceeded the carrying value of the related reporting unit. Therefore, no impairment was indicated.

Environmental Obligations and Other Contingencies

Management makes judgments and estimates in accordance with applicable accounting rules when it establishes reserves for environmental remediation, litigation, and other contingent matters. Provisions for such matters are charged to expense when it is probable that a liability is incurred and reasonable estimates of the liability can be made. Estimates of environmental liabilities are based on a variety of matters, including, but not limited to, the stage of investigation, the stage of the remedial design, evaluation of existing remediation technologies, and presently enacted laws and regulations. In future periods, a number of factors could significantly change the Company's estimate of environmental-remediation costs, such as changes in laws and regulations, changes in the interpretation or administration of laws and regulations, revisions to the remedial design, unanticipated construction problems, identification of additional areas or volumes of contaminated soil and groundwater, and changes in costs of labor, equipment, and technology. Consequently, it is not possible for management to reliably estimate the amount and timing of all future expenditures related to environmental or other contingent matters and actual costs may vary significantly from the Company's estimates. The Company's in-house legal counsel and environmental personnel regularly assess these contingent liabilities and, in certain circumstances, consults with third-party legal counsel or consultants to assist in forming the Company's conclusion.

Impairment of Long-Lived Assets

A long-lived asset other than unproved oil and gas property is evaluated for potential impairment whenever events or changes in circumstances indicate that its carrying value may be greater than its future net undiscounted cash flows. Impairment, if any, is measured as the excess of an asset's carrying amount over its estimated fair value. The Company utilizes a variety of fair-value measurement techniques when market information for the same or similar assets does not exist.

Derivative Instruments

All derivative instruments, other than those that satisfy specific exceptions, are recorded at fair value. If market quotes are not available to estimate fair value, management's best estimate of fair value is based on the quoted market price of derivatives with similar characteristics or determined through industry-standard valuation techniques.

The Company's derivative instruments are either exchange-traded or transacted in an over-the-counter market. Valuation is determined by reference to readily available public data for similar instruments. Option fair values are measured using the Black-Scholes option-pricing model and verified by comparing a sample to market quotes for similar options. Unrealized gains or losses on derivatives are recorded to current earnings.

Income Taxes

The amount of income taxes recorded by the Company requires interpretations of complex rules and regulations of various tax jurisdictions throughout the world. The Company has recognized deferred tax assets and liabilities for temporary differences, operating losses, and tax credit carryforwards. The Company routinely assesses the realizability of its deferred tax assets and reduces such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. The Company routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts. The accruals for deferred tax assets and liabilities, including deferred state income tax assets and liabilities, are subject to significant judgment by management and are reviewed and adjusted routinely based on changes in facts and circumstances. Although management considers its tax accruals adequate, material changes in these accruals may occur in the future, based on the progress of ongoing tax audits, changes in legislation, and resolution of pending tax matters.

Benefit Plan Obligations

The Company has non-contributory U.S. defined-benefit pension plans, including both qualified and supplemental plans, and a foreign contributory defined-benefit pension plan. The Company also provides certain health care and life insurance benefits for certain retired employees. Determination of the benefit obligations for the Company's defined-benefit pension and postretirement plans impacts the recorded amounts for such obligations on the balance sheet and the amount of benefit expense recorded to the income statement.

Accounting for pension and other postretirement benefit obligations involves many assumptions, the most significant of which are the discount rate used to measure the present value of plan benefit obligations, the expected long-term rate of return on plan assets (for funded pension plans), the rate of future increases in compensation levels of participating employees, and the future level of health care costs.

The Company amortizes prior service costs and credits on a straight-line basis over the average remaining service period of employees expected to receive benefits under each plan. Actuarial gains and losses that exceed 10% of the greater of the projected benefit obligation and the market-related value of assets are amortized over the average remaining service period of participating employees expected to receive benefits under each plan.

Discount rate

Accumulated and projected benefit obligations are measured as the present value of future cash payments. The Company discounts those cash payments using a discount rate that reflects the weighted average of market-observed yields for select high quality (AA-rated) fixed-income securities with cash flows that correspond to the expected amounts and timing of benefit payments. Discount-rate selection for measurements prior to December 31, 2011, was based on a similar cash-flow-matching analysis, although, instead of using a portfolio of select high quality fixed-income securities to determine the effective settlement rate for a given plan obligation, the Company relied primarily on a published yield curve derived from market-observed yields for a universe of high quality bonds. Both methods are acceptable and result in a discount-rate assumption that represents an estimate of the interest rate at which the pension and other postretirement benefit obligations could effectively be settled on the measurement date. However, the Company believes a discount rate reflecting yields for high-quality fixed-income securities better corresponds to the Company's expectations as to the amount and timing of its benefit payments. Assumed rates of compensation increases for active participants vary by age group. The weighted-average assumed rate (weighted by the plan-level benefit obligation) used to measure the Company's December 31, 2011 pension benefit obligations was 4.50%, and the weighted-average discount-rate assumption for other postretirement benefit obligations, which are longer in duration, was 4.75%.

Expected long-term rate of return

The expected long-term rate of return on plan assets assumption was determined using the year-end 2011 pension investment balances by asset class and expected long-term asset allocation. The expected return for each asset class reflects capital-market projections formulated using a forward-looking building-block approach, while also taking into account historical return trends and current market conditions. Equity returns generally reflect long-term expectations of real earnings growth, dividend yield, and inflation. Returns on fixed-income securities are generally developed based on expected inflation, real bond yield, and risk spread (as appropriate), adjusted for the expected effect that changing yields have on the rate of return. Other asset class returns are derived from their relationship to the equity and fixed income markets. Because the assumption reflects the Company's expectation of average annualized return over a long time horizon, generally, it is not expected to be significantly revised from year to year, even though actual rates of investment return from year to year often experience significant volatility.

To measure the net periodic pension cost for its funded pension plans, Anadarko assumed an average long-term rate of return of 7.0%. A variation in this assumption of 25 basis points would have changed the measure of 2011 net periodic pension cost by approximately $3 million pretax, with higher investment return assumption resulting in lower recognized expense.

Rate of compensation increases

The Company's rate of compensation increases assumption is based on its long-term plans for compensation increases specific to covered employee groups and expected economic conditions. The assumed rate of salary increases includes the effects of merit increases, promotions, and general labor cost inflation within the oil and gas industry. The benefit obligations at December 31, 2011, reflect assumed rates of long-term compensation increases for active participants that vary by age group, with the resulting weighted-average rate (weighted by the plan-level benefit obligation) of 4.5%.

Health care cost trend rate

The health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. A 9% annual rate of increase in the per-capita cost of covered health care benefits was assumed for 2012, decreasing gradually to 5% in 2018 and beyond.

RECENT ACCOUNTING DEVELOPMENTS

In 2011, the FASB issued an Accounting Standards Update (ASU) that permits an initial assessment of qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount for goodwill impairment testing purposes. Thus, determining a reporting unit's fair value is not required unless, as a result of a qualitative assessment, it is more likely than not that the fair value of the reporting unit is less than its carrying amount. This ASU is effective for periods beginning after December 15, 2011. Adoption of this ASU will have no impact on the Company's consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company's primary market risks are attributable to fluctuations in energy prices and interest rates. In addition, foreign-currency exchange-rate risk exists due to anticipated foreign-currency denominated payments and receipts. These risks can affect revenues and cash flows from operating, investing, and financing activities. The Company's risk-management policies provide for the use of derivative instruments to manage these risks. The types of commodity derivative instruments utilized by the Company include futures, swaps, options, and fixed-price physical-delivery contracts. The volume of commodity derivatives entered into by the Company is governed by risk-management policies and may vary from year to year. Both exchange and over-the-counter traded commodity derivative instruments may be subject to margin deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or counterparties in order to satisfy these margin requirements.

For information regarding the Company's accounting policies and additional information related to the Company's derivative and financial instruments, see *Note 1—Summary of Significant Accounting Policies* and *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

COMMODITY PRICE RISK The Company's most significant market risk relates to prices for natural gas, crude oil, and NGLs. Management expects energy prices to remain volatile and unpredictable. As energy prices decline or rise significantly, revenues and cash flows are likewise affected. In addition, a non-cash write-down of the Company's oil and gas properties or goodwill may be required if commodity prices experience a significant and sustained decline. Below is a sensitivity analysis for the Company's commodity-price-related derivative instruments.

Derivative Instruments Held for Non-Trading Purposes The Company had derivative instruments in place to reduce the price risk associated with future production of 662 Bcf of natural gas at year-end 2011. The Company had a net derivative asset position of $619 million on these derivative instruments at December 31, 2011. Based on actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these derivatives by $140 million, while a 10% decrease in underlying commodity prices would increase the fair value of these derivatives by $134 million. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instruments.

Derivative Instruments Held for Trading Purposes The Company had a net derivative asset position of $43 million (gains of $87 million and losses of $44 million) on derivative instruments entered into for trading purposes at December 31, 2011. Based on actual derivative contractual volumes, a 10% increase or decrease in underlying commodity prices would not materially impact the Company's gains or losses on these derivative instruments.

For additional information regarding the Company's marketing and trading portfolio, see *Marketing Activities* under Items 1 and 2 of this Form 10-K.

INTEREST-RATE RISK The Company's $2.5 billion of borrowings under its $5.0 billion Facility are subject to variable interest rates. The remaining reported balance of Anadarko's long-term debt in the Company's Consolidated Balance Sheets was at fixed interest rates. The Company's $2.9 billion of LIBOR-based obligations, which are presented net of preferred investments in two non-controlled entities on the Company's Consolidated Balance Sheets, give rise to minimal net interest-rate risk exposure because coupons on the related preferred investments are also LIBOR-based. See *Note 9—Investments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. A 10% increase in LIBOR would not materially impact the Company's interest cost on debt already outstanding, but would affect the fair value of outstanding debt, as well as interest cost associated with future debt issuances.

At December 31, 2011, the Company had a net derivative liability position of $1.2 billion related to interest-rate swaps. A 10% increase or decrease in the three-month LIBOR interest-rate curve would increase or decrease, respectively, the aggregate fair value of outstanding interest-rate swap agreements by approximately $116 million. However, any change in the interest-rate derivative gain or loss would be substantially offset by an increase or decrease, respectively, in borrowing costs associated with future debt issuances and the Company's borrowings under its $5.0 billion Facility. For a summary of the Company's open interest-rate derivative positions, see *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

FOREIGN-CURRENCY EXCHANGE-RATE RISK Anadarko's operating revenues are realized in U.S. dollars, and the predominant portion of Anadarko's capital and operating expenditures are U.S. dollar denominated. Exposure to foreign-currency risk generally arises in connection with project-specific contractual arrangements and other commitments. Near-term foreign-currency-denominated expenditures are primarily in euros, Brazilian reais, and British pounds sterling. Management periodically enters into transactions to mitigate a portion of its exposure to foreign-currency exchange-rate risk.

With respect to international oil and gas development projects, Anadarko is a party to contracts containing remaining commitments extending through November 2012 that are impacted by euro-to-U.S. dollar exchange rates. To manage euro exchange-rate risk relative to euro-denominated commitments, the Company held approximately €98 million, or $127 million, cash and cash equivalents and also held euro-U.S. dollar collars during 2011. Euro purchases mitigate the Company's exposure to fluctuations in the euro-to-U.S. dollar exchange rate inherent in its existing capital expenditure commitments.

The Company also has risk related to exchange-rate changes applicable to cash held in escrow pending final determination of the Company's Brazilian tax liability for its 2008 divestiture of the Peregrino field offshore Brazil. At December 31, 2011, cash of $182 million was held in escrow. A 10% increase or decrease in the foreign-currency exchange rate would not materially impact the Company's gain or loss related to foreign currency.

Item 8. Financial Statements and Supplementary Data

ANADARKO PETROLEUM CORPORATION

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

ANADARKO PETROLEUM CORPORATION

REPORT OF MANAGEMENT

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

MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Anadarko's 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.

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.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011. This assessment was based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we believe that as of December 31, 2011, the Company's internal control over financial reporting was effective based on those criteria.

KPMG LLP has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2011.

/s/ JAMES T. HACKETT

James T. Hackett
Chairman and Chief Executive Officer

/s/ ROBERT G. GWIN

Robert G. Gwin
Senior Vice President, Finance and Chief Financial Officer

February 21, 2012

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Anadarko Petroleum Corporation:

We have audited Anadarko Petroleum Corporation's internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Anadarko Petroleum Corporation's 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 in the accompanying *Management's Assessment of Internal Control over Financial Reporting*. 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, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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, Anadarko Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2011, and our report dated February 21, 2012 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 21, 2012

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Anadarko Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2011. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Anadarko Petroleum Corporation's internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 21, 2012 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 21, 2012

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

millions except per-share amounts	Years Ended December 31, 2011	2010	2009
Revenues and Other			
Natural-gas sales	**$ 3,300**	$ 3,420	$ 2,924
Oil and condensate sales	**8,072**	5,592	4,022
Natural-gas liquids sales	**1,462**	997	536
Gathering, processing, and marketing sales	**1,048**	833	728
Gains (losses) on divestitures and other, net	**85**	142	133
Reversal of accrual for Deepwater Royalty Relief Act dispute	**—**	—	657
Total	**13,967**	10,984	9,000
Costs and Expenses			
Oil and gas operating	**993**	830	859
Oil and gas transportation and other	**891**	816	664
Exploration	**1,076**	974	1,107
Gathering, processing, and marketing	**791**	615	617
General and administrative	**1,060**	967	983
Depreciation, depletion, and amortization	**3,830**	3,714	3,532
Other taxes	**1,492**	1,068	746
Impairments	**1,774**	216	115
Deepwater Horizon settlement and related costs	**3,930**	15	—
Total	**15,837**	9,215	8,623
Operating Income (Loss)	**(1,870)**	1,769	377
Other (Income) Expense			
Interest expense	**839**	855	702
(Gains) losses on commodity derivatives, net	**(562)**	(893)	408
(Gains) losses on other derivatives, net	**1,023**	285	(582)
Other (income) expense, net	**254**	(119)	(43)
Total	**1,554**	128	485
Income (Loss) Before Income Taxes	**(3,424)**	1,641	(108)
Income Tax Expense (Benefit)	**(856)**	820	(5)
Net Income (Loss)	**(2,568)**	821	(103)
Net Income Attributable to Noncontrolling Interests	**81**	60	32
Net Income (Loss) Attributable to Common Stockholders	**$ (2,649)**	$ 761	$ (135)
Per Common Share:			
Net income (loss) attributable to common stockholders—basic	**$ (5.32)**	$ 1.53	$ (0.28)
Net income (loss) attributable to common stockholders—diluted	**$ (5.32)**	$ 1.52	$ (0.28)
Average Number of Common Shares Outstanding—Basic	**498**	495	480
Average Number of Common Shares Outstanding—Diluted	**498**	497	480
Dividends (per Common Share)	**$ 0.36**	$ 0.36	$ 0.36

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

millions	Years Ended December 31, 2011	2010	2009
Net Income (Loss)	**$ (2,568)**	$ 821	$ (103)
Other Comprehensive Income (Loss), net of taxes			
Reclassification of previously deferred derivative losses to net income[(1)]	**10**	17	22
Adjustments for pension and other postretirement plans:			
Net gain (loss) incurred during period[(2)]	**(136)**	(91)	(131)
Prior service credit (cost) incurred during period[(3)]	**7**	(4)	—
Amortization of net actuarial loss and prior service cost to net periodic benefit cost[(4)]	**56**	41	37
Total adjustments for pension and other postretirement plans	**(73)**	(54)	(94)
Other	**—**	—	1
Total	**(63)**	(37)	(71)
Comprehensive Income (Loss)	**(2,631)**	784	(174)
Comprehensive Income Attributable to Noncontrolling Interests	**81**	60	32
Comprehensive Income (Loss) Attributable to Common Stockholders	**$ (2,712)**	$ 724	$ (206)

(1) Net of income tax benefit (expense) of $(5) million, $(9) million, and $(12) million for the years ended December 31, 2011, 2010, and 2009, respectively.

(2) Net of income tax benefit (expense) of $77 million, $52 million, and $74 million for the years ended December 31, 2011, 2010, and 2009, respectively.

(3) Net of income tax benefit (expense) of $(5) million and $2 million for the years ended December 31, 2011 and 2010, respectively.

(4) Net of income tax benefit (expense) of $(31) million, $(23) million, and $(21) million for the years ended December 31, 2011, 2010, and 2009, respectively.

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS

millions	December 31, 2011	December 31, 2010
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 2,697**	$ 3,680
Accounts receivable, net of allowance:		
Customers	**1,269**	1,032
Others	**1,990**	1,391
Other current assets	**975**	572
Total	**6,931**	6,675
Properties and Equipment		
Cost	**60,081**	54,815
Less accumulated depreciation, depletion, and amortization	**22,580**	16,858
Net properties and equipment	**37,501**	37,957
Other Assets	**1,516**	1,616
Goodwill and Other Intangible Assets	**5,831**	5,311
Total Assets	**$ 51,779**	$ 51,559
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	**$ 3,299**	$ 2,726
Accrued expenses	**1,430**	1,097
Current portion of long-term debt	**170**	291
Total	**4,899**	4,114
Long-term Debt	**15,060**	12,722
Other Long-term Liabilities		
Deferred income taxes	**8,479**	9,861
Asset retirement obligations	**1,737**	1,529
Other	**2,621**	1,894
Total	**12,837**	13,284
Equity		
Stockholders' equity		
Common stock, par value $0.10 per share (1.0 billion shares authorized, 516.0 million and 513.3 million shares issued as of December 31, 2011 and 2010, respectively)	**51**	51
Paid-in capital	**7,851**	7,496
Retained earnings	**11,619**	14,449
Treasury stock (17.6 million and 17.1 million shares as of December 31, 2011 and 2010, respectively)	**(804)**	(763)
Accumulated other comprehensive income (loss)	**(612)**	(549)
Total Stockholders' Equity	**18,105**	20,684
Noncontrolling interests	**878**	755
Total Equity	**18,983**	21,439
Total Liabilities and Equity	**$ 51,779**	$ 51,559

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY

	Total Stockholders' Equity						
millions	Common Stock	Paid-in Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total Equity
Balance at December 31, 2008	$ 47	$ 5,696	$ 14,179	$ (686)	$ (441)	$ 361	$ 19,156
Net income (loss)	—	—	(135)	—	—	32	(103)
Common stock issued	3	1,547	—	—	—	—	1,550
Dividends—common	—	—	(176)	—	—	—	(176)
Repurchase of common stock	—	—	—	(35)	—	—	(35)
Sale of subsidiary units[(1)]	—	—	—	—	—	115	115
Contributions from (distributions to) noncontrolling interest owners and other, net	—	—	—	—	—	(21)	(21)
Reclassification of previously deferred derivative losses to net income	—	—	—	—	22	—	22
Adjustments for pension and other postretirement plans	—	—	—	—	(94)	—	(94)
Other	—	—	—	—	1	—	1
Balance at December 31, 2009	50	7,243	13,868	(721)	(512)	487	20,415
Net income (loss)	—	—	761	—	—	60	821
Common stock issued	1	253	—	—	—	—	254
Dividends—common	—	—	(180)	—	—	—	(180)
Repurchase of common stock	—	—	—	(42)	—	—	(42)
Sale of subsidiary units[(1)]	—	—	—	—	—	295	295
Contributions from (distributions to) noncontrolling interest owners and other, net	—	—	—	—	—	(87)	(87)
Reclassification of previously deferred derivative losses to net income	—	—	—	—	17	—	17
Adjustments for pension and other postretirement plans	—	—	—	—	(54)	—	(54)
Balance at December 31, 2010	**51**	**7,496**	**14,449**	**(763)**	**(549)**	**755**	**21,439**
Net income (loss)	**—**	**—**	**(2,649)**	**—**	**—**	**81**	**(2,568)**
Common stock issued	**—**	**161**	**—**	**—**	**—**	**—**	**161**
Dividends—common	**—**	**—**	**(181)**	**—**	**—**	**—**	**(181)**
Repurchase of common stock	**—**	**—**	**—**	**(41)**	**—**	**—**	**(41)**
Sale of subsidiary units[(1)]	**—**	**32**	**—**	**—**	**—**	**269**	**301**
Conversion of subordinated limited partner units to common units[(2)]	**—**	**162**	**—**	**—**	**—**	**(162)**	**—**
Contributions from (distributions to) noncontrolling interest owners and other, net	**—**	**—**	**—**	**—**	**—**	**(65)**	**(65)**
Reclassification of previously deferred derivative losses to net income	**—**	**—**	**—**	**—**	**10**	**—**	**10**
Adjustments for pension and other postretirement plans	**—**	**—**	**—**	**—**	**(73)**	**—**	**(73)**
Balance at December 31, 2011	**$ 51**	**$ 7,851**	**$ 11,619**	**$ (804)**	**$ (612)**	**$ 878**	**$ 18,983**

(1) Paid-in capital and noncontrolling interests includes $18 million and $9 million, respectively, of tax associated with subsidiary equity transactions for the year ended December 31, 2011. Noncontrolling interests includes $43 million and $5 million of tax associated with subsidiary equity transactions for the years ended December 31, 2010 and 2009, respectively.

(2) Includes $82 million of tax associated with subsidiary equity transactions that occurred prior to the conversion of subordinated limited partner units to common units.

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

millions	Years Ended December 31, 2011	2010	2009
Cash Flows from Operating Activities			
Net income (loss)	**$ (2,568)**	$ 821	$ (103)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, and amortization	**3,830**	3,714	3,532
Deferred income taxes	**(1,461)**	(123)	(165)
Dry hole expense and impairments of unproved properties	**625**	682	780
Impairments	**1,774**	216	115
(Gains) losses on divestitures, net	**(22)**	(29)	(44)
Unrealized (gains) losses on derivatives, net	**616**	(114)	717
Reversal of accrual for Deepwater Royalty Relief Act dispute	**—**	—	(657)
Other	**454**	213	183
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	**(989)**	(172)	(290)
Increase (decrease) in accounts payable and accrued expenses	**287**	(157)	269
Other items—net	**(41)**	196	(411)
Net cash provided by (used in) operating activities	**2,505**	5,247	3,926
Cash Flows from Investing Activities			
Additions to properties and equipment and dry hole costs	**(5,650)**	(5,008)	(4,352)
Acquisition of midstream businesses	**(802)**	—	—
Divestitures of properties and equipment and other assets	**555**	70	176
Other—net	**(78)**	(26)	(60)
Net cash provided by (used in) investing activities	**(5,975)**	(4,964)	(4,236)
Cash Flows from Financing Activities			
Borrowings, net of issuance costs	**3,551**	3,198	1,975
Repayments of debt	**(1,154)**	(1,879)	(1,470)
Repayment of midstream subsidiary note payable to a related party	**—**	(1,599)	(140)
Repayment of capital lease obligation	**(108)**	—	—
Increase (decrease) in accounts payable, banks	**149**	7	(139)
Dividends paid	**(181)**	(180)	(176)
Repurchase of common stock	**(41)**	(42)	(35)
Issuance of common stock, including tax benefit on stock option exercises	**30**	107	1,372
Sale of subsidiary units	**328**	338	120
Distributions to noncontrolling interest owners	**(82)**	(48)	(29)
Other financing activities	**18**	(24)	3
Net cash provided by (used in) financing activities	**2,510**	(122)	1,481
Effect of Exchange Rate Changes on Cash	**(23)**	(12)	—
Net Increase (Decrease) in Cash and Cash Equivalents	**(983)**	149	1,171
Cash and Cash Equivalents at Beginning of Period	**3,680**	3,531	2,360
Cash and Cash Equivalents at End of Period	**$ 2,697**	$ 3,680	$ 3,531

See accompanying Notes to Consolidated Financial Statements.

1. Summary of Significant Accounting Policies

General Anadarko Petroleum Corporation is engaged in the exploration, development, production, and marketing of natural gas, crude oil, condensate, and natural gas liquids (NGLs). In addition, the Company engages in the gathering, processing, and treating of natural gas, and the transporting of natural gas, crude oil, and NGLs. The Company also participates in the hard minerals business through its ownership of non-operated joint ventures and royalty arrangements. Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries.

Basis of Presentation The Consolidated Financial Statements have been prepared in conformity with accounting principles generally accepted in the United States. The Consolidated Financial Statements include the accounts of Anadarko and entities in which it holds a controlling interest. All intercompany transactions have been eliminated. Undivided interests in oil and natural-gas exploration and production joint ventures are consolidated on a proportionate basis. Investments in non-controlled entities, over which Anadarko has the ability to exercise significant influence over operating and financial policies, are accounted for using the equity method. In applying the equity method of accounting, the investments are initially recognized at cost, and subsequently adjusted for the Company's proportionate share of earnings and losses and distributions. Other investments are carried at original cost. Investments accounted for using the equity- and cost-method are reported as a component of other assets. Certain prior-period amounts have been reclassified to conform to the current-year presentation.

Use of Estimates In preparing financial statements in accordance with accounting principles generally accepted in the United States, management makes informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. Management evaluates its estimates and related assumptions regularly, including those related to the value of properties and equipment; proved reserves; goodwill; intangible assets; asset retirement obligations; litigation reserves; environmental liabilities; pension assets, liabilities, and costs; income taxes; and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Fair Value Fair value is defined as the price that would be received to sell an asset or the price paid to transfer a liability in an orderly transaction between market participants at the measurement date. Inputs used in determining fair value are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. The three input levels of the fair-value hierarchy are as follows:

Level 1—Inputs represent quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives).

Level 2—Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).

Level 3—Inputs that are not observable from objective sources, such as the Company's internally developed assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in the Company's internally developed present value of future cash flows model that underlies the fair-value measurement).

1. Summary of Significant Accounting Policies (Continued)

In determining fair value, the Company utilizes observable market data when available, or models that incorporate observable market data. In addition to market information, the Company incorporates transaction-specific details that, in management's judgment, market participants would take into account in measuring fair value.

In arriving at fair-value estimates, the Company utilizes the most observable inputs available for the valuation technique employed. If a fair-value measurement reflects inputs at multiple levels within the hierarchy, the fair-value measurement is characterized based on the lowest level of input that is significant to the fair-value measurement. For Anadarko, recurring fair-value measurements are performed for interest-rate derivatives, commodity derivatives, and investments in trading securities.

The carrying amount of cash and cash equivalents, accounts receivable, and accounts payable reported on the Consolidated Balance Sheets approximates fair value. The fair value of debt is the estimated amount the Company would have to pay to repurchase its debt, including any premium or discount attributable to the difference between the stated interest rate and market rate of interest at each balance sheet date. Debt fair values, as disclosed in *Note 12—Debt and Interest Expense*, are based on quoted market prices for identical instruments, if available, or based on valuations of similar debt instruments.

Non-financial assets and liabilities initially measured at fair value include certain assets and liabilities acquired in a business combination or through a non-monetary exchange transaction, intangible assets, goodwill, asset retirement obligations, exit or disposal costs, and capital lease assets where the present value of lease payments is greater than the fair value of the leased asset.

Revenues The Company's natural gas is sold primarily to interstate and intrastate natural-gas pipelines, direct end-users, industrial users, local distribution companies and natural-gas marketers. Oil and condensate are sold primarily to marketers, gatherers, and refiners. NGLs are sold primarily to direct end-users, refiners, and marketers. In 2011, 2010, and 2009, there were no sales to individual customers that exceeded 10% of the Company's total sales revenues.

The Company recognizes sales revenues for natural gas, oil and condensate, and NGLs based on the amount of each product sold to purchasers when delivery to the purchaser has occurred and title has transferred. This occurs when product has been delivered to a pipeline or a tanker lifting has occurred. The Company follows the sales method of accounting for natural-gas production imbalances. If the Company's sales volumes for a well exceed the Company's proportionate share of production from the well, a liability is recognized to the extent that the Company's share of estimated remaining recoverable reserves from the well is insufficient to satisfy this imbalance. No receivables are recorded for those wells on which the Company has taken less than its proportionate share of production.

The Company enters into buy/sell arrangements for a portion of its crude-oil production. Under these arrangements, barrels are sold at prevailing market prices at a location, and in an additional transaction entered into in contemplation of the sale transaction with the same third party, barrels are re-purchased at a different location at the market prices prevailing at that location. The barrels are then sold at prevailing market prices at the re-purchase location. These arrangements are often required by private transporters. In these transactions, the re-purchase price is more than the original sales price with the difference representing a transportation fee. Other buy/sell arrangements are entered in order to shift the ultimate sales point of the Company's production to a more liquid location, thereby avoiding potential marketing fees and other market-price reductions. In these transactions, the sales price in the field and the re-purchase price are each at prevailing market prices at the respective locations. Anadarko uses buy/sell arrangements in its marketing and trading activities and reports these transactions in the Consolidated Statements of Income on a net basis.

Anadarko provides gathering, processing, treating, and transportation services pursuant to a variety of contracts. Under these arrangements, the Company receives fees, or retains a percentage of products or a percentage of the proceeds from the sale of products and recognizes revenue at the time the services are performed or product is sold. These revenues are included in gathering, processing, and marketing sales.

1. Summary of Significant Accounting Policies (Continued)

Marketing margins related to the Company's production are included in natural-gas sales, oil and condensate sales, and NGLs sales. Marketing margins related to sales of commodities purchased from third parties, as well as realized and unrealized gains and losses on derivatives related to such marketing activities are included in gathering, processing, and marketing sales.

Cash Equivalents The Company considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

Allowance for Uncollectible Accounts The Company conducts credit analyses of customers prior to making any sales to new customers or increasing credit for existing customers. Based on these analyses, the Company may require a standby letter of credit or a financial guarantee. The Company charges uncollectible accounts receivable against the allowance for uncollectible accounts when it determines collection will no longer be pursued. At December 31, 2011 and 2010, accounts receivable are shown net of allowance for uncollectible accounts of $6 million and $9 million, respectively.

Inventories Commodity inventories are stated at the lower of average cost or market.

Properties and Equipment Properties and equipment are stated at cost less accumulated depreciation, depletion, and amortization expense (DD&A). Costs of improvements that appreciably improve the efficiency or productive capacity of existing properties or extend their lives are capitalized. Maintenance and repairs are expensed as incurred. Upon retirement or sale, the cost of properties and equipment, net of the related accumulated DD&A, is removed and, if appropriate, gain or loss is recognized in gains (losses) on divestitures and other, net.

Oil and Gas Properties The Company applies the successful efforts method of accounting for oil and gas properties. Exploration costs such as exploratory geological and geophysical costs, delay rentals, and exploration overhead are charged against earnings as incurred. If an exploratory well provides evidence to justify potential completion as a producing well, drilling costs associated with the well are initially capitalized, or suspended, pending a determination as to whether a commercially sufficient quantity of proved reserves can be attributed to the area as a result of drilling. This determination may take longer than one year in certain areas (generally, deepwater and international locations) depending on, among other things, the amount of hydrocarbons discovered, the outcome of planned geological and engineering studies, the need for additional appraisal drilling activities to determine whether the discovery is sufficient to support an economic development plan, and government sanctioning of development activities in certain international locations. At the end of each quarter, management reviews the status of all suspended exploratory drilling costs in light of ongoing exploration activities—in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, whether development negotiations are underway and proceeding as planned. If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory drilling costs are expensed.

Acquisition costs of unproved properties are periodically assessed for impairment and are transferred to proved oil and gas properties to the extent the costs are associated with successful exploration activities. Significant undeveloped leases are assessed individually for impairment, based on the Company's current exploration plans, and a valuation allowance is provided if impairment is indicated. Unproved oil and gas properties with individually insignificant lease acquisition costs are amortized on a group basis (thereby establishing a valuation allowance) over the average terms of the leases, at rates that provide for full amortization of unsuccessful leases upon lease expiration or abandonment. Costs of expired or abandoned leases are charged against the valuation allowance, while costs of productive leases are transferred to proved oil and gas properties. Costs of maintaining and retaining unproved properties, as well as amortization of individually insignificant leases and impairment of unsuccessful leases, are included in exploration expense.

1. Summary of Significant Accounting Policies (Continued)

Capitalized Interest For significant projects, interest is capitalized as part of the historical cost of developing and constructing assets. Significant oil and gas investments in unproved properties, significant exploration and development projects for which DD&A is not currently recognized, and exploration or development activities that are in progress qualify for interest capitalization. Interest is capitalized until the asset is ready for service. Capitalized interest is determined by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred. Once an asset subject to interest capitalization is completed and placed in service, the associated capitalized interest is expensed through depreciation or impairment.

Asset Retirement Obligations Asset retirement obligations (AROs) associated with the retirement of tangible long-lived assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived assets in the period incurred. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. AROs are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligations discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. If estimated future costs of AROs change, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment.

Impairments Properties and equipment, net of salvage value, are reviewed for impairment at the lowest level for which identifiable cash flows are independent of cash flows from other assets, and when facts and circumstances indicate that net book values may not be recoverable. In performing this review, an undiscounted cash flow test is performed on the impairment unit. If the sum of the undiscounted future net cash flows is less than the net book value of the property, an impairment loss is recognized for the excess, if any, of the property's net book value over its estimated fair value.

Depreciation, Depletion, and Amortization Costs of drilling and equipping successful wells, costs to construct or acquire facilities other than offshore platforms, associated asset retirement costs, and capital lease assets are depreciated using the unit-of-production (UOP) method based on total estimated proved developed oil and gas reserves. Costs of acquiring proved properties, including leasehold acquisition costs transferred from unproved properties and costs to construct or acquire offshore platforms and associated asset retirement costs, are depleted using the UOP method based on total estimated proved developed and undeveloped reserves. Mineral properties are also depleted using the UOP method. All other properties are stated at historical acquisition cost, net of impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 3 to 15 years for furniture and equipment, up to 40 years for buildings, and up to 47 years for gathering facilities.

Goodwill and Other Intangible Assets Goodwill is subject to annual impairment testing at October 1 (or more frequent testing as circumstances dictate). Anadarko has allocated goodwill to four reporting units: oil and gas exploration and production; other gathering and processing; Western Gas Partners, LP (WES) gathering and processing; and transportation. Changes in goodwill may result from, among other things, impairments, future acquisitions, or future divestitures. See *Note 7—Goodwill and Other Intangible Assets.*

Other intangible assets represent contractual rights obtained in connection with business combinations that had favorable contractual terms relative to market at the acquisition date. Other intangible assets are amortized over their estimated useful lives and are assessed for impairment whenever impairment indicators are present. See *Note 7—Goodwill and Other Intangible Assets.*

1. Summary of Significant Accounting Policies (Continued)

Derivative Instruments Anadarko uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risk. All derivatives that do not satisfy the normal purchases and sales exception criteria are carried on the balance sheet at fair value and are included in other current assets, other assets, accrued expenses, or other long-term liabilities, depending on the derivative position and the expected timing of settlement. Where the Company has the contractual right and intends to net settle, derivative assets and liabilities are reported on a net basis.

Realized and unrealized gains and losses on derivative instruments are recognized on a current basis. Net derivative losses attributable to derivatives previously subject to hedge accounting reside in accumulated other comprehensive income and will be reclassified to earnings in future periods as the economic transactions to which the derivatives relate affect earnings. See *Note 10—Derivative Instruments*.

Accounts Payable Included in accounts payable at December 31, 2011 and 2010, are liabilities of \$408 million and \$259 million, respectively, representing the amount by which checks issued, but not presented to the Company's banks for collection, exceed balances in applicable bank accounts. Changes in these liabilities are reflected in cash flows from financing activities.

Legal Contingencies The Company is subject to legal proceedings, claims, and liabilities that arise in the ordinary course of its business. Except for legal contingencies acquired in a business combination, which are recorded at fair value, the Company accrues losses associated with legal claims when such losses are probable and reasonably estimable. Estimates are adjusted as additional information becomes available or circumstances change. Legal defense costs associated with loss contingencies are expensed in the period incurred. See *Note 2—Deepwater Horizon Events* and *Note 16—Contingencies*.

Environmental Contingencies Except for environmental contingencies acquired in a business combination, which are recorded at fair value, the Company accrues losses associated with environmental obligations when such losses are probable and can be reasonably estimated. Accruals for estimated environmental losses are recognized no later than at the time the remediation feasibility study, or the evaluation of response options, is complete. These accruals are adjusted as additional information becomes available or as circumstances change. Future environmental expenditures are not discounted to their present value. Recoveries of environmental costs from other parties are recorded separately as assets at their undiscounted value when receipt of such recoveries is probable. See *Note 2—Deepwater Horizon Events* and *Note 16—Contingencies*.

Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans The Company measures pension plan assets at fair value. Defined-benefit plan obligations and costs are actuarially determined, incorporating the use of various assumptions. Critical assumptions for pension and other postretirement plans include the discount rate, the expected long-term rate of return on plan assets (for funded pension plans), the rate of future compensation increases, and the health care cost trend rate. Other assumptions involve demographic factors such as retirement age, mortality, and turnover. The Company evaluates and updates its actuarial assumptions at least annually.

The Company amortizes prior service costs and credits on a straight-line basis over the average remaining service period of employees expected to receive benefits under each plan. Actuarial gains and losses that exceed 10% of the greater of the projected benefit obligation and the market-related value of assets are amortized over the average remaining service period of participating employees expected to receive benefits under each plan. See *Note 21—Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans*.

Noncontrolling Interests Noncontrolling interests represent third-party ownership in the net assets of the Company's consolidated subsidiaries and are presented as a component of equity. Changes in Anadarko's ownership interests in subsidiaries that do not result in deconsolidation are recognized in equity. See *Note 8—Noncontrolling Interests*.

1. Summary of Significant Accounting Policies (Continued)

Income Taxes The Company files various U.S. federal, state, and foreign income tax returns. Deferred federal, state, and foreign income taxes are provided on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. The Company routinely assesses the realizability of its deferred tax assets. If the Company concludes that is it more likely than not that some of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. The Company recognizes a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. The tax benefit recorded is equal to the largest amount that is greater than 50% likely to be realized through final settlement with a taxing authority. Interest and penalties related to unrecognized tax benefits are recognized in income tax expense (benefit). See *Note 18—Income Taxes*.

Share-Based Compensation The Company accounts for share-based compensation at fair value. The Company grants equity-classified awards including stock options and non-vested equity shares (restricted stock awards and units). The Company also grants equity-classified and liability-classified awards based on a comparison of the Company's total shareholder return (TSR) to the TSR of a predetermined group of peer companies (performance units).

The fair value of stock option awards is determined on the date of grant using the Black-Scholes option-pricing model. Restricted stock awards and units are valued using the market price of Anadarko common stock on the grant date. For equity- and liability-classified performance units, fair value is determined using a Monte Carlo simulation or discounted cash flow methodology.

The Company records compensation cost, net of estimated forfeitures, for share-based compensation awards over the requisite service period. As each award of stock options or equity shares vests, an adjustment is made to compensation cost for any difference between the estimated forfeitures and the actual forfeitures related to the vested awards. For share-based awards that contain service conditions, compensation cost is recorded using the straight-line method. If the requisite service period is satisfied, compensation cost is not adjusted. For liability-classified performance units, expense is recognized over the requisite performance period for those awards expected to ultimately be paid. The amount of expense reported is adjusted throughout the performance period for fair-value changes so that the expense recognized for each award is equivalent to the amount to be paid. See *Note 14—Share-Based Compensation*.

Earnings Per Share The Company's basic earnings per share (EPS) is computed based on the average number of shares of common stock outstanding for the period and include the effect of any participating securities as appropriate. Diluted EPS includes the effect of the Company's outstanding stock options, restricted stock awards, restricted stock units, and performance-based stock awards if the inclusion of these items is dilutive. See *Note 13—Stockholders' Equity*.

Recently Issued Accounting Standards Not Yet Adopted In 2011, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) that permits an initial assessment of qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount for goodwill impairment testing purposes. Thus, determining a reporting unit's fair value is not required unless, as a result of a qualitative assessment, it is more likely than not that the fair value of the reporting unit is less than its carrying amount. This ASU is effective for periods beginning after December 15, 2011. Adoption of this ASU will have no impact on the Company's consolidated financial statements.

2. Deepwater Horizon Events

Background, Settlement, and BP Indemnification In April 2010, the Macondo well in the Gulf of Mexico, in which Anadarko held a 25% non-operating leasehold interest, discovered hydrocarbon accumulations. During suspension operations, the well blew out, an explosion occurred on the *Deepwater Horizon* drilling rig, and the drilling rig sank, resulting in the release of hydrocarbons into the Gulf of Mexico. Eleven people lost their lives in the explosion and subsequent fire, and others sustained personal injuries. The Macondo well was plugged on September 19, 2010. BP Exploration & Production Inc. (BP), the operator of Mississippi Canyon Block 252 in which the Macondo well is located (Lease), is funding claims and coordinating cleanup efforts.

In October 2011, the Company and BP entered into a settlement agreement, mutual releases, and agreement to indemnify, relating to the Deepwater Horizon events (Settlement Agreement). Pursuant to the Settlement Agreement, the Company paid $4.0 billion and transferred its interest in the Macondo well and the Lease to BP, and BP accepted this consideration in full satisfaction of its claims against Anadarko for $6.1 billion of invoices issued through the settlement date as well for potential reimbursements of subsequent costs incurred by BP related to the Deepwater Horizon events, including costs under the Operating Agreement (OA). In addition, BP fully indemnified Anadarko against all claims, causes of action, losses, costs, expenses, liabilities, damages, or judgments of any kind arising out of the Deepwater Horizon events, related damage claims arising under the Oil Pollution Act of 1990 (OPA), claims for natural resource damages (NRD) and associated damage-assessment costs, and any claims arising under the OA. This indemnification is guaranteed by BP Corporation North America Inc. (BPCNA) and, in the event that the net worth of BPCNA declines below an agreed-upon amount, BP p.l.c. has agreed to become the sole guarantor. Under the Settlement Agreement, BP does not indemnify the Company against fines and penalties, punitive damages, shareholder, derivative, or security laws claims, or certain other claims. The Company believes that costs associated with non-indemnified items, individually or in the aggregate, will not materially impact the Company's consolidated financial position, results of operations, or cash flows.

Liability Accrual The $4.0 billion settlement amount was expensed in the third quarter of 2011, and payment was remitted to BP in November 2011 in accordance with the Settlement Agreement. Below is a discussion of the Company's current analysis, under applicable accounting guidance, of its potential liability for (i) amounts invoiced by BP under the OA (OA Liabilities), (ii) OPA-related environmental costs, and (iii) other contingent liabilities. Accounting rules require loss recognition where a potential loss is considered probable and can be reasonably estimated.

The Company is fully indemnified by BP against OPA damage claims, NRD claims and assessment costs, and other potential liabilities. The Company may be required to recognize a liability for these amounts in advance of or in connection with recognizing a receivable from BP for the related indemnity payment. In all circumstances, however, the Company expects that any additional indemnified liability that may be recognized by the Company will be subsequently recovered from BP itself or through the guarantees of BPCNA or BP p.l.c. The Company has not recorded a liability for any costs that are subject to indemnification by BP.

OA Liabilities Pursuant to the Settlement Agreement, all amounts deemed by BP to have been due under the OA, as well as all future amounts that otherwise would be invoiced to Anadarko under the OA, have been satisfied.

OPA-Related Environmental Costs BP, Anadarko, and other parties, including parties that do not own an interest in the Lease, such as the drilling contractor, have received correspondence from the U.S. Coast Guard (USCG) referencing their identification as a "responsible party or guarantor" (RP) under OPA. Under OPA, RPs, including Anadarko, may be jointly and severally liable for costs of well control, spill response, and containment and removal of hydrocarbons, as well as other costs and damage claims related to the spill and spill cleanup. The USCG's identification of Anadarko as an RP arises as a result of Anadarko's status as a co-lessee in the Lease.

2. Deepwater Horizon Events (Continued)

Applicable accounting guidance requires the Company to accrue an environmental liability if it is both probable that a liability is incurred and the amount of the liability can be reasonably estimated. Under accounting guidance applicable to environmental liabilities, a liability is presumed probable if the entity is both identified as an RP and associated with the environmental event. The Company's co-lessee status in the Lease and the subsequent identification and treatment of the Company as an RP satisfies these standards and therefore establishes the presumption that the Company's potential environmental liabilities related to the Deepwater Horizon events are probable. Given that such liabilities are probable, the Company must separately assess and estimate the Company's allocable share of gross estimated OPA-related environmental costs.

As BP funds OPA-related environmental costs, any potential joint and several liability for these costs is satisfied for all RPs, including Anadarko. This bears significance in that once these costs are funded by BP, such costs are no longer analyzed as OPA-related environmental costs, but are instead analyzed as OA Liabilities. As discussed above, Anadarko has agreed with BP to settle its current and future OA Liabilities. Thus, potential liability to the Company for OPA-related environmental costs can only arise where BP does not, or otherwise is unable to, fund all of the OPA-related environmental costs. Under this scenario, the joint and several nature of the liability for these costs could cause the Company to recognize a liability for OPA-related environmental costs. However, the Company is fully indemnified by BP against these costs (including guarantees by BPCNA or BP p.l.c.).

Gross OPA-Related Environmental Cost Estimate In prior periods, the Company provided an estimated range of gross OPA-related environmental costs for all identified RPs. This estimate was comprised of spill-response costs and OPA damage claims and was derived from cost information received by the Company from BP. The Company no longer receives Deepwater Horizon-related cost and claims data from BP. Accordingly, the OPA-related environmental cost estimate included in BP's public releases is the best data available to the Company.

Based on information included in BP p.l.c.'s public release on February 7, 2012, the range of gross OPA-related environmental costs is estimated to be $6.0 billion to $10.0 billion, excluding (i) amounts BP has already funded, which constitute settled OA Liabilities; (ii) amounts that in BP's view cannot reasonably be estimated, which include NRD claims and other litigation damages; and (iii) non-OPA-related fines and penalties that may be assessed against Anadarko, including assessments under the Clean Water Act (CWA). Actual gross OPA-related environmental costs may vary from those estimated by BP p.l.c. in its public releases, perhaps materially from the above estimate.

Allocable Share of Gross OPA-Related Environmental Costs Under applicable accounting guidance, the Company is required to estimate its allocable share of gross OPA-related environmental costs. To date, BP has paid all Deepwater Horizon event-related costs, which satisfies the Company's potential liability for these costs. Additionally, BP has repeatedly stated publicly and in prior congressional testimony that it will continue to pay these costs. BP's funding and public commentary has continued subsequent to the release of BP's own investigation report, the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling's final report, and the Deepwater Horizon Joint Investigation Team final report, which the Company considers to be significant positive indications in assessing the likelihood of BP continuing to fund all of these costs. Based on BP's stated intent to continue funding these costs, the Company's assessment of BP's financial ability to continue funding these costs, and the impact of BP's settlements with both of its OA partners, the Company believes the likelihood of BP not continuing to satisfy these claims to be remote. Accordingly, the Company considers zero to be its allocable share of gross OPA-related environmental costs and, consistent with applicable accounting guidance, has not recorded a liability for these amounts.

2. Deepwater Horizon Events (Continued)

Other Contingencies

Penalties and Fines These costs include amounts that may be assessed as a result of potential civil and/or criminal penalties under various federal, state, and/or local statutes and/or regulations as a result of the Deepwater Horizon events, including, for example, the CWA, the Outer Continental Shelf Lands Act, the Migratory Bird Treaty Act, and possibly other federal, state, and local laws. The foregoing does not represent an exhaustive list of statutes and regulations that potentially could trigger a penalty or fine assessment against the Company.

To date, no penalties or fines have been assessed against the Company. However, on December 15, 2010, the U.S. Department of Justice (DOJ), on behalf of the United States, filed a civil lawsuit in the U.S. District Court in New Orleans, Louisiana (Louisiana District Court) against several parties, including Anadarko Petroleum Corporation and Anadarko E&P Company LP (AE&P), a subsidiary of Anadarko, seeking an assessment of civil penalties under the CWA in an amount to be determined by the Louisiana District Court. The DOJ complaint seeks separate penalty assessments against both Anadarko Petroleum Corporation and AE&P (based on a temporary interest that AE&P at one time held in the Lease). In April 2011, the Company moved to dismiss AE&P from the DOJ lawsuit because the effective date of AE&P's transfer of its interest in the Lease to Anadarko Petroleum Corporation pre-dated the Deepwater Horizon events. In December 2011, the United States moved for partial summary judgment against, among others, Anadarko Petroleum Corporation and AE&P for a declaration of liability for penalties under the CWA. Anadarko Petroleum Corporation and AE&P opposed the United States' motion and cross-moved for summary judgment for a declaration of non-liability for CWA penalties. The Court heard oral arguments on these and the other parties' motions in January 2012 and has taken the motions under advisement. The Company currently believes it is probable that AE&P will not be found liable for CWA penalties upon the presentation of evidence. The Company believes the outcome of this decision will not have a material impact on Anadarko's potential liability.

Although Anadarko is named in the DOJ civil lawsuit, its status as a defendant does not mean that Anadarko will be liable for a CWA penalty in that action. First, the Company has a defense to liability under the CWA based on the location from which the discharge occurred. If the court finds that the discharge of hydrocarbons came from the vessel (which includes the riser pipe), the Company may not be liable under the CWA because it neither owned nor operated the *Deepwater Horizon* drilling rig. Second, because CWA penalties, in practice, are generally assessed on a party-specific basis and take into account several factors including the party's degree of fault, the Company considers its lack of direct involvement in the operation of the drilling rig and the spill itself significant in concluding that losses from CWA penalty assessments are not probable. This view was reinforced by the Louisiana District Court's decision that dismissed all negligence claims against the Company based on the court's finding that the Company did not exercise operational control over the events that led to the oil spill. Accordingly, the Company does not consider a liability for CWA penalties to be probable and, therefore, has not recorded a liability for potential CWA penalties. The February 2012 financial settlement of CWA penalties by the other non-operating partner (February 2012 Settlement) did not affect the Company's current conclusion regarding the likelihood of loss attributable to CWA penalties. The Company does not believe that the February 2012 Settlement impacts the Company's valid defenses.

In addition to concluding that any liability for CWA penalties is not probable, the Company currently cannot estimate the amount of any potential penalty. The CWA sets forth subjective criteria, including degree of fault and history of prior violations, which influence CWA penalty assessments. Thus, as a result of the subjective nature of CWA penalty assessments, the Company currently cannot estimate the amount of any such penalty. The Company does not consider the financial terms of the February 2012 Settlement to be indicative of any potential loss that ultimately may be borne by the Company. The Company lacks insight into the content of the February 2012 Settlement discussions, retains legal counsel separate from the other non-operating party, and was not involved in any manner with respect to the February 2012 Settlement.

2. Deepwater Horizon Events (Continued)

Given the Company's lack of direct operational involvement in the event, as recently confirmed by the Louisiana District Court, the Company believes that its potential exposure to CWA penalties will not materially impact the Company's consolidated financial position, results of operations, or cash flows.

Natural Resource Damages This category includes future damage claims that may be made by federal and/or state natural resource trustee agencies at the completion of injury assessments and restoration planning. Natural resources generally include land, fish, water, air, wildlife, and other such resources belonging to, managed by, held in trust by, or otherwise controlled by, the federal, state, or local government.

The NRD-assessment process is led by government agencies that act as trustees of natural resources on behalf of the public. Government agencies involved in the process include the Department of Commerce, the Department of the Interior (DOI), and the Department of Defense. These governmental departments, along with the five affected states – Alabama, Florida, Louisiana, Mississippi, and Texas – are referred to as the "Co-Trustees." The Co-Trustees continue to conduct injury assessment and restoration planning.

The DOJ civil lawsuit filed against BP, the Company, and others seeks unspecified damages for injury to federal natural resources. Not all of the Co-Trustees were a party to this lawsuit; however, during the second quarter of 2011, the states of Alabama and Louisiana each filed NRD-related state law claims against the Company in the Louisiana District Court. The Court heard oral arguments on these and other parties' motions in September 2011. In November 2011, the Court dismissed all the NRD-related state law claims asserted against the Company by the states of Alabama and Louisiana. These states have subsequently appealed the Court's decision.

NRD claims are generally sought after the damage assessment and restoration planning is completed, which may take several years. Thus, the Company remains unable to reasonably estimate the magnitude of any NRD claim. The Company anticipates that BP will satisfy any NRD claim, which eliminates any potential liability to Anadarko for such costs. In the event any NRD damage claim is made directly against Anadarko, the Company is fully indemnified by BP against such claims (including guarantees by BPCNA or BP p.l.c).

Civil Litigation Damage Claims Numerous civil lawsuits have been filed against BP and other parties, including the Company, by, among others, fishing, boating, and shrimping enterprises and industry groups; restaurants; commercial and residential property owners; certain rig workers or their families; the State of Alabama and several of its political subdivisions; the DOJ; environmental non-governmental organizations; the State of Louisiana and certain of its political subdivisions; and certain Mexican states. Many of the lawsuits filed assert various claims of negligence, gross negligence, and violations of several federal and state laws and regulations, including, among others, OPA; the Comprehensive Environmental Response, Compensation, and Liability Act; the Clean Air Act; the CWA; and the Endangered Species Act; or challenge existing permits for operations in the Gulf of Mexico. Generally, the plaintiffs are seeking actual damages, punitive damages, declaratory judgment, and/or injunctive relief.

In August 2010, the U.S. Judicial Panel on Multidistrict Litigation created Multidistrict Litigation No. 2179 (MDL) to administer essentially all pretrial matters for litigation filed in federal court involving Deepwater Horizon event-related claims. Federal Judge Carl Barbier presides over this MDL in the Louisiana District Court. The Louisiana District Court has issued a number of case-management orders that establish a schedule for procedural matters, discovery, and trial of certain of the MDL cases. The parties to the MDL are actively engaged in discovery. In May 2011, September 2011, and November 2011, Judge Barbier heard oral arguments on the numerous motions to dismiss filed by the multiple defendants named in this litigation. While a number of the motions remain pending, Judge Barbier has dismissed all maritime and state law claims filed against the Company seeking damages for economic loss. All negligence claims filed against the Company have been dismissed based upon Judge Barbier's finding that the Company did not exercise operational control

2. Deepwater Horizon Events (Continued)

over the events that led to the oil spill. In a separate order, Judge Barbier reached similar findings and dismissed all claims against the Company filed by private plaintiffs alleging personal injury caused by exposure to oil, fumes or other contaminants from the blowout or the chemical dispersants used during the post-spill cleanup operations. Judge Barbier further found that federal law exclusively applies to claims for property damage and economic loss and dismissed all state law claims against the Company asserting liability for such damages and losses. Only OPA claims asserted seeking economic loss damages against the Company remain. The Company, pursuant to the Settlement Agreement, is fully indemnified by BP against such OPA claims.

The Louisiana District Court has scheduled a February 2012 trial in Transocean's Limitation of Liability case in the MDL. This trial is to be the first phase of a three-phase trial, each phase designed to address different issues. The first phase of the trial is to determine certain liability issues and the liability allocation among the parties alleged to be involved in or liable for the Deepwater Horizon events. In April 2011, the Company filed its answer in this Limitation of Liability case and cross-claimed against affiliates of BP and Transocean Ltd. (Transocean), Halliburton Energy Services, Inc. (Halliburton), Cameron International Corporation (Cameron), and other third-party defendants. Transocean, Halliburton, and Cameron subsequently filed cross-claims against the Company. In November 2011, the Court dismissed all cross-claims against the Company. Under the Settlement Agreement, a mutual release of all claims, including claims that were the subject of cross-claims made by the Company against BP, was agreed to by the Company and BP. The Company has also assigned all rights, title, and interest to all claims that have been or could be asserted against third parties, including cross-claims filed against third-party defendants, to BP, with the exception of rights to claims the Company may assert under its insurance policies.

Lawsuits seeking to place limitations on the oil and gas industry's operations in the Gulf of Mexico, including those of the Company, have also been filed outside of the MDL by non-governmental organizations against various governmental agencies. These cases are filed in the Louisiana District Court, the U.S. District Courts for the Southern District of Alabama and the District of Columbia, and in the U.S. Court of Appeals for the Fifth Circuit.

Two separate class action complaints were filed in June and August 2010, in the U.S. District Court for the Southern District of New York (New York District Court) on behalf of purported purchasers of the Company's stock between June 9, 2009, and June 12, 2010, against Anadarko and certain of its officers. The complaints allege causes of action arising pursuant to the Securities Exchange Act of 1934 for purported misstatements and omissions regarding, among other things, the Company's liability related to the Deepwater Horizon events. The plaintiffs seek an unspecified amount of compensatory damages, including interest thereon, as well as litigation fees and costs. In November 2010, the New York District Court consolidated the two cases and appointed The Pension Trust Fund for Operating Engineers and Employees' Retirement System of the Government of the Virgin Islands (Virgin Islands Group) to act as Lead Plaintiff. In January 2011, the Lead Plaintiff filed its Consolidated Amended Complaint. Prior to filing its Consolidated Amended Complaint, the Lead Plaintiff requested leave from the New York District Court to transfer this lawsuit to the U.S. District Court for the Southern District of Texas. The Company opposes the Lead Plaintiff's request to transfer the case to the District Court for the Southern District of Texas. The parties have submitted briefs to the New York District Court concerning the transfer of venue issue. In March 2011, the Company moved to dismiss the Consolidated Amended Complaint of the Lead Plaintiff, and in April 2011, the Lead Plaintiff filed its opposition to the motion to dismiss. The motion to transfer and motion to dismiss remain under advisement of the New York District Court.

Also in June 2010, a shareholder derivative petition was filed in the 152nd Judicial District Court of Harris County, Texas (Harris County District Court), by a shareholder of the Company against Anadarko (as a nominal defendant), certain of its officers, and current and certain former directors. The petition alleged breaches of fiduciary duties, unjust enrichment, and waste of corporate assets in connection with the Deepwater Horizon events. The plaintiffs sought certain changes to the Company's governance and internal procedures, disgorgement of profits, and reimbursement of litigation fees and costs. In November 2010, the Harris County District Court granted Anadarko's

2. Deepwater Horizon Events (Continued)

Motion to Dismiss for Lack of Jurisdiction and Special Exceptions, and granted the plaintiffs 120 days to file an Amended Petition. In March 2011, the plaintiffs filed an Amended Petition. The Company filed Special Exceptions and a Motion to Dismiss the Amended Petition in April 2011. In June 2011, the Harris County District Court heard oral arguments on these matters and granted the motion to dismiss. The time for the plaintiffs to appeal has expired.

In November 2011, the Company's Board of Directors received a letter from a purported shareholder demanding that the Board investigate, address, remedy, and commence derivative proceedings against certain officers and directors for their alleged breach of fiduciary duty related to Deepwater Horizon events. The Board has considered this demand and will respond in due course.

Given the early stages of these proceedings, the Company currently cannot assess the probability of losses, or reasonably estimate a range of any potential losses, related to ongoing proceedings. The Company intends to vigorously defend itself, its officers, and its directors in all proceedings, and will avail itself of any and all indemnities provided by BP against civil damages.

Remaining Liability Outlook It is reasonably possible that the Company may recognize additional Deepwater Horizon event-related liabilities for potential fines and penalties, shareholder claims, and certain other claims not covered by the indemnification provisions of the Settlement Agreement; however, the Company does not believe that any potential liability attributable to the foregoing items, individually or in the aggregate, will have a material impact on the Company's consolidated financial position, results of operations, or cash flows.

The Company will continue to monitor the MDL and other legal proceedings discussed above as well as federal investigations related to the Deepwater Horizon events, including the investigation by the U.S. Chemical Safety Board. The Company cannot predict the nature of evidence that may be discovered during the course of legal proceedings and investigations, the timing of discovery, or the timing of completion of any legal proceedings or investigations.

Although the Company is fully indemnified by BP against OPA damage claims, NRD claims and assessment costs, and certain other potential liabilities, the Company may be required to recognize a liability for these amounts in advance of or in connection with recognizing a receivable from BP for the related indemnity payment. In all circumstances, however, the Company expects that any additional indemnified liability that may be recognized by the Company will be subsequently recovered from BP itself or through the guarantees of BPCNA or BP p.l.c.

Insurance and Other Recoveries The Company carries insurance to protect against potential financial losses. During the fourth quarter of 2011, the Company recorded a gain of $163 million for insurance proceeds related to Deepwater Horizon events. This amount is included in Deepwater Horizon settlement and related costs in the Company's Consolidated Statement of Income for the year ended December 31, 2011. The Company also carries directors' and officers' insurance which covers certain risks associated with certain of the above-described legal proceedings.

As part of the Settlement Agreement, BP has agreed that, to the extent it receives value in the future from claims that it has asserted or could assert against third parties arising from or relating to the Deepwater Horizon events, it will make cash payments (not to exceed $1.0 billion in the aggregate) to Anadarko, on a current and continuing basis, of 12.5% of the aggregate value received by BP in excess of $1.5 billion. Any payments received by the Company pursuant to this arrangement will be accounted for as a reimbursement of the $4.0 billion payment made by the Company to BP as part of the Settlement Agreement.

3. Acquisitions

In May 2011, Anadarko increased its ownership interest in a natural-gas processing plant (Wattenberg Plant), located in northeast Colorado, by acquiring an additional 93% interest for $576 million. Anadarko operates and owns a 100% interest in the Wattenberg Plant.

In February 2011, WES, a consolidated subsidiary of the Company, acquired a natural-gas processing plant and related gathering systems (Platte Valley), located in northeast Colorado, for $302 million.

These acquisitions, along with future expansion plans, align Anadarko's natural-gas processing capacity with the Company's anticipated production growth in the Rocky Mountains Region (Rockies). In addition, these acquisitions position the Company to improve field recoveries and realize operational cost efficiencies.

The Wattenberg Plant and Platte Valley acquisitions constitute business combinations and were accounted for using the acquisition method. The following summarizes the preliminary fair value of assets acquired and liabilities assumed at the acquisition dates:

millions	
Properties and equipment	**$ 298**
Intangible assets	**165**
Deferred income taxes	**31**
Other assets	**4**
Other liabilities	**(21)**
Goodwill	**362**
Total assets acquired and liabilities assumed	**839**
Less: Fair value of Anadarko's pre-acquisition 7% equity interest in the Wattenberg Plant	**37**
Acquisition of midstream businesses	**802**
Loss on Anadarko's preexisting contracts with the previous Wattenberg Plant owner	**76**
Total consideration paid	**$ 878**

All fair-value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and thus represent Level 3 inputs. The fair value of acquired properties and equipment is based on market and cost approaches. Intangible assets consist of customer contracts, the fair value of which was determined using an income approach. Deferred tax assets represent the tax effects of differences in the tax basis and acquisition-date fair values of assets acquired and liabilities assumed. Liabilities assumed include asset retirement obligations existing at the date of acquisition, and are valued consistent with the Company's policy for estimating such obligations.

Assets acquired and liabilities assumed are included within the midstream reporting segment, except for $335 million of goodwill and a portion of the related deferred tax asset recognized in connection with the Wattenberg Plant acquisition, which are included in the oil and gas exploration and production reporting segment. Goodwill of $469 million related to the Wattenberg Plant acquisition is amortizable for tax purposes.

Goodwill from these acquisitions is included in the oil and gas exploration and production reporting segment and the midstream reporting segment based on the increase in fair value to each of the respective reporting segments. The increase in fair value to these reporting segments is derived from improved NGLs volume retention from equity production and the alignment of Company-controlled natural-gas processing capacity with future production growth plans in the Rockies. See *Note 7—Goodwill and Other Intangible Assets*.

Prior to the Wattenberg Plant acquisition, the Company was party to natural-gas processing contracts with the previous Wattenberg Plant owner. As a result of the acquisition, these preexisting contracts were terminated, causing the Company to recognize a $76 million loss, which is included in gains (losses) on divestitures and other, net in the Consolidated Statement of Income for the year ended December 31, 2011. This loss represents the aggregate amount by which the contracts were unfavorable as compared to current market transactions for the same or similar services at the date the Company acquired the Wattenberg Plant.

3. Acquisitions (Continued)

The Company also recognized a gain of $21 million from the acquisition-date fair-value remeasurement of its pre-acquisition 7% equity interest in the Wattenberg Plant. The gain is included in gains (losses) on divestitures and other, net in the Consolidated Statement of Income for the year ended December 31, 2011.

Results of operations attributable to the Wattenberg Plant and Platte Valley acquisitions are included in the Company's Consolidated Statements of Income from the dates acquired. The amounts of revenue and earnings included in the Company's Consolidated Statement of Income for the year ended December 31, 2011, and the amounts of revenue and earnings that would have been recognized had the acquisitions occurred on January 1, 2010, are not material to the Company's Consolidated Statements of Income.

4. Divestitures and Assets Held for Sale

In 2011, the Company received $419 million in satisfaction of the contingent consideration related to the 2008 divestiture of its interest in the Peregrino field offshore Brazil. The Company also recognized losses on assets held for sale of $422 million during 2011 as the Company began marketing certain onshore domestic properties from both the oil and gas exploration and production reporting segment and the midstream reporting segment in order to redirect its operating activities and capital investment to other areas. Losses on assets held for sale consist of $390 million related to oil and gas exploration and production reporting segment properties and $32 million related to midstream reporting segment properties. These assets were impaired to fair value, estimated using Level 2 and Level 3 fair-value inputs. At December 31, 2011, net properties and equipment, goodwill and other intangible assets, and other long-term liabilities on the Company's Consolidated Balance Sheets included $320 million, $38 million, and $75 million, respectively, associated with assets held for sale.

In 2010, proceeds from divestitures of $70 million and net gains on divestitures of $29 million are primarily related to U.S. onshore oil and gas properties. During 2009, the Company closed several unrelated property divestiture transactions, realizing proceeds of $176 million and net gains on divestitures of $44 million. The 2009 gains included $29 million related to divestitures of certain oil and gas properties in Qatar.

5. Inventories

The major classes of inventories, included in other current assets as of December 31, are as follows:

millions	**2011**	2010
Crude oil	**$ 103**	$ 126
Natural gas	**49**	64
NGLs	**59**	61
Total	**$ 211**	$ 251

6. Properties and Equipment

A summary of the cost of properties and equipment by segment as of December 31, are as follows:

millions	**2011**	2010
Oil and gas exploration and production(1)	**$ 52,711**	$ 48,328
Midstream	**4,837**	4,060
Marketing	**9**	9
Other	**2,524**	2,418
Total	**$ 60,081**	$ 54,815

(1) Includes costs associated with unproved properties of $8.3 billion and $9.8 billion at December 31, 2011 and 2010, respectively.

6. Properties and Equipment (Continued)

During 2011, the Company recognized impairments of $1.7 billion related to long-lived assets. These impairments include $1.2 billion and $458 million related to U.S. properties included in the oil and gas exploration and production and midstream reporting segment, respectively. These impairments were primarily due to decreases in natural-gas prices. All of these assets were impaired to fair value, estimated using Level 3 fair-value inputs. Impairments and depreciation reduced the net book value of assets impaired during 2011 to $688 million at December 31, 2011.

During 2010, the Company recognized impairments of $147 million related to long-lived assets. These impairments include $114 million related to a production platform included in the oil and gas exploration and production reporting segment that remains idle with no immediate plan for use, and for which a limited market exists. Other long-lived assets included in the oil and gas exploration and production reporting segment were impaired by $31 million, which were primarily located in the Southern and Appalachia Region. These assets were impaired to fair value, which was estimated using Level 3 inputs. Impairments and depreciation reduced the net book value of assets impaired during 2010 to $51 million at December 31, 2010.

During 2009, the Company recognized impairments of $41 million related to long-lived assets, including $22 million related to the oil and gas exploration and production reporting segment triggered by the economic and commodity price environment, $7 million associated with certain gathering and processing facilities in the midstream reporting segment due to reduced operating activity, and $12 million related to a liquefied natural gas facility site, included in the marketing reporting segment. These assets were impaired to fair value, which was estimated using Level 3 inputs. Impairments and depreciation reduced the net book value of assets impaired in 2009 to $26 million at December 31, 2009.

Suspended Exploratory Drilling Costs The following presents the amount of suspended exploratory drilling costs at December 31 for each of the last three years, and changes to those amounts during the years then ended. The following excludes amounts for new projects capitalized and subsequently reclassified to proved oil and gas properties or charged to expense within the same year.

millions	**2011**	2010	2009
Balance at January 1	**$ 935**	$ 579	$ 279
Additions pending the determination of proved reserves	**572**	491	483
Reclassifications to proved properties	**(116)**	(106)	(120)
Charges to exploration expense	**(38)**	(29)	(63)
Balance at December 31	**$ 1,353**	$ 935	$ 579

The following presents suspended exploratory drilling costs by geographic area and by year of origination at December 31, 2011.

		Year Costs Incurred		
millions	**Total**	**2011**	**2010**	**2009 and prior**
United States—Onshore	$ 110	$ 96	$ 4	$ 10
United States—Offshore	233	(5)	60	178
International	1,010	468	312	230
	$ 1,353	$ 559	$ 376	$ 418

6. Properties and Equipment (Continued)

Suspended exploratory drilling costs capitalized for a period greater than one year after completion of drilling at December 31, 2011, were $794 million and were associated with 20 projects, primarily located in the Gulf of Mexico, Brazil, Ghana, Sierra Leone, and Mozambique. All project costs suspended for longer than one year were primarily suspended pending the completion of economic evaluations including, but not limited to, results of additional appraisal drilling, facilities, infrastructure, well-test analysis, additional geological and geophysical data, development plan approval, and permitting. Management believes projects with suspended exploratory drilling costs exhibit sufficient quantities of hydrocarbons to justify potential development and is actively pursuing efforts to assess whether reserves can be attributed to the respective areas. If additional information becomes available that raises substantial doubt as to the economic or operational viability of any of these projects, the associated costs will be expensed at that time.

7. Goodwill and Other Intangible Assets

Goodwill The Company completed its annual impairment assessment of goodwill during the fourth quarter of 2011, and the test indicated no impairment. At December 31, 2011, the Company had $5.6 billion of goodwill allocated as follows: $5.4 billion to oil and gas exploration and production; $102 million to other gathering and processing; $59 million to WES gathering and processing; and $5 million to transportation.

Significant declines in commodity prices, difficulty or potential delays in obtaining drilling permits, or other unanticipated events could result in further goodwill impairment tests in the near term, the results of which may have a material adverse impact on the Company's results of operations.

Other Intangible Assets Intangible assets subject to amortization and associated amortization expense are as follows:

millions	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Expense
December 31, 2011				
Offshore platform leases	**$ 60**	**$ (33)**	**$ 27**	**$ 2**
Customer contracts	**165**	**(2)**	**163**	**2**
	$ 225	**$ (35)**	**$ 190**	**$ 4**
December 31, 2010				
Offshore platform leases	$ 60	$ (31)	$ 29	$ 3
	$ 60	$ (31)	$ 29	$ 3

Customer contract intangible assets are primarily related to the Wattenberg Plant acquisition and are included in the Company's midstream reporting segment, and are being amortized over 50 years. See *Note 3—Acquisitions.* The estimated aggregate amortization expense for all intangible assets for the next five years is not expected to be material.

8. Noncontrolling Interests

WES, a consolidated subsidiary, is a limited partnership formed by Anadarko to own, operate, acquire, and develop midstream assets. In 2011 and 2010, WES issued approximately 10 million and 13 million common units to the public, respectively, raising net proceeds of $328 million and $338 million, respectively, which increased the noncontrolling interest component of total equity.

In August 2011, the WES subordinated limited partner units held by Anadarko converted to common limited partner units on a one-for-one basis. Upon this conversion, $162 million related to pre-conversion changes in the Company's ownership interest in WES was transferred from noncontrolling interests to paid-in capital. Additionally, $32 million was recorded to paid-in capital as a result of WES's third-quarter 2011 issuance of common units. The Company's net income (loss) attributable to common stockholders, together with the above-described increases to Anadarko's paid-in capital, for the year ended December 31, 2011, totaled $(2,455) million. At December 31, 2011, Anadarko's ownership interest in WES consisted of a 43.3% limited partner interest, a 2% general partner interest, and incentive distribution rights.

9. Investments

Noncontrolling Mandatorily Redeemable Interests In 2007, Anadarko contributed certain of its oil and gas properties and gathering and processing assets, with an aggregate fair value of $2.9 billion at the time of the contribution, to newly formed unconsolidated entities in exchange for noncontrolling mandatorily redeemable London Interbank Offered Rate (LIBOR) based preferred interests in those entities. The common equity of the investee entities is 95% owned by third parties that also maintain control over the assets. Subsequent to their formation, the investee entities loaned Anadarko an aggregate of $2.9 billion. The Company accounts for its investment in these entities using the equity method of accounting. The carrying amount of these investments was $2.8 billion and the carrying amount of notes payable to affiliates was $2.9 billion at December 31, 2011. Anadarko has legal right of setoff and intends to net-settle its obligations under each of the notes payable to the investees with the distributable value of its interest in the corresponding investee. Accordingly, the investments and the obligations are presented net on the Consolidated Balance Sheets with the excess of the notes payable to affiliates over the aggregate investment carrying amounts reported in other long-term liabilities—other for all periods presented.

Interest on the notes issued by Anadarko is variable, based on LIBOR, plus a spread that fluctuates with Anadarko's credit rating. The applicable interest rate was 1.55% and 1.30% at December 31, 2011 and 2010, respectively. The note payable agreement contains a covenant that provides for a maximum debt-to-capital ratio of 67%. Anadarko was in compliance with this covenant at December 31, 2011. Other (income) expense, net for 2011, 2010, and 2009, includes interest expense on the notes payable of $38 million, $39 million, and $57 million, respectively, and equity earnings from Anadarko's investments in the investee entities of $(41) million, $(37) million, and $(42) million, respectively.

Other During 2011 and 2010, the Company recognized impairment expense of $91 million ($37 million net of tax) and $61 million ($23 million net of tax), respectively, related to the Company's cost-method investment in Venezuelan assets due to changes in expected recoverable reserves. These assets are included in the oil and gas exploration and production reporting segment and were impaired to fair value, estimated using Level 3 fair-value inputs. The Company's after-tax net investment in these assets was $39 million and $70 million at December 31, 2011 and 2010, respectively.

10. Derivative Instruments

Objective and Strategy The Company uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risks.

Futures, swaps, and options are used to manage exposure to commodity-price risk inherent in the Company's oil and natural-gas production and natural-gas processing operations (Oil and Natural-Gas Production/Processing Derivative Activities). Futures contracts and commodity-price swap agreements are used to fix the price of expected future oil and natural-gas sales at major industry trading locations, such as Henry Hub for natural gas and Cushing for oil. Basis swaps are used to fix or float the price differential between product prices at one market location versus another. Options are used to establish a floor price, a ceiling price, or a floor and a ceiling price (collar) for expected future oil and natural-gas sales. Derivative instruments are also used to manage commodity-price risk inherent in customer price requirements and to fix margins on the future sale of natural gas and NGLs from the Company's leased storage facilities (Marketing and Trading Derivative Activities).

Interest-rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to unfavorable interest-rate changes. The fair value of this swap portfolio increases (decreases) when interest rates increase (decrease).

The Company does not apply hedge accounting to any of its derivative instruments. As a result, both realized and unrealized gains and losses associated with derivative instruments are recognized in earnings. Net derivative losses attributable to derivatives previously subject to hedge accounting reside in accumulated other comprehensive income (loss) and are reclassified to earnings as the transactions to which the derivatives relate are recognized in earnings. Accumulated other comprehensive loss balances of $109 million ($70 million after tax) and $125 million ($79 million after tax) at December 31, 2011 and 2010, respectively, relate to interest-rate derivatives that were previously subject to hedge accounting.

Oil and Natural-Gas Production/Processing Derivative Activities Below is a summary of the Company's derivative instruments related to its Oil and Natural-Gas Production/Processing Activities at December 31, 2011. The natural-gas prices listed below are New York Mercantile Exchange (NYMEX) Henry Hub prices. The crude-oil prices listed below are NYMEX Cushing prices.

	2012	2013
Natural Gas		
Three-Way Collars (thousand MMBtu/d)	—[(1)]	450
Average price per MMBtu		
Ceiling sold price (call)	$ —	$ 6.57
Floor purchased price (put)	$ —	$ 5.00
Floor sold price (put)	$ —	$ 4.00
Fixed-Price Contracts (thousand MMBtu/d)	1,000	—
Average price per MMBtu	$ 4.69	$ —
Crude Oil		
Three-Way Collars (MBbls/d)	2	—
Average price per barrel		
Ceiling sold price (call)	$ 92.50	$ —
Floor purchased price (put)	$ 50.00	$ —
Floor sold price (put)	$ 35.00	$ —

(1) Includes the effects of offsetting purchased and sold natural-gas three-way collars of 500,000 MMBtu/d.
MMBtu—million British thermal units
MMBtu/d—million British thermal units per day
MBbls/d—thousand barrels per day

10. Derivative Instruments (Continued)

A three-way collar is a combination of three options: a sold call, a purchased put, and a sold put. The sold call establishes the maximum price that the Company will receive for the contracted commodity volumes. The purchased put establishes the minimum price that the Company will receive for the contracted volumes unless the market price for the commodity falls below the sold put strike price, at which point the minimum price equals the reference price (e.g., NYMEX) plus the excess of the purchased put strike price over the sold put strike price.

Marketing and Trading Derivative Activities In addition to the positions in the above tables, the Company also engages in marketing and trading activities, which include physical product sales and related derivative transactions used to manage commodity-price risk. At December 31, 2011 and 2010, the Company had fixed-price physical transactions related to natural gas totaling 22 billion cubic feet (Bcf) and 32 Bcf, respectively, offset by derivative transactions for 21 Bcf and 28 Bcf, respectively, for net positions of 1 Bcf and 4 Bcf, respectively.

Interest-Rate Derivatives In December 2008 and January 2009, Anadarko entered into interest-rate swap contracts as a fixed-rate payor to mitigate the interest-rate risk associated with anticipated 2011 and 2012 debt issuances. The Company locked in a fixed interest rate in exchange for a floating interest rate indexed to the three-month LIBOR. The swap instruments include a provision that requires both the termination of the swaps and cash settlement in full at the start of the reference period.

Due to rising interest rates in 2009, the fair value of the swap contracts increased. As a result, the Company revised the swap contract terms in the second quarter of 2009 to increase the weighted-average interest rate of the swap portfolio from approximately 3.25% to approximately 4.80%, and realized a $552 million gain. During the third quarter of 2011, in order to better align the swap portfolio with the anticipated timing of future debt refinancing, the Company extended the swap maturity dates from October 2011 to June 2014 for interest-rate swaps with an aggregate notional principal amount of $1.85 billion. In connection with these extensions, the swap interest rates were also adjusted. In addition, interest-rate swap agreements with an aggregate notional principal amount of $150 million were settled for a loss of $57 million in October 2011.

The Company had the following outstanding interest-rate swaps at December 31, 2011.

millions except percentages	Reference Period		Weighted-Average
Notional Principal Amount	**Start**	**End**	**Interest Rate**
$ 250	October 2012	October 2022	4.91%
$ 750	October 2012	October 2042	4.80%
$ 750	June 2014	June 2024	6.00%
$ 1,100	June 2014	June 2044	5.57%

10. Derivative Instruments (Continued)

Effect of Derivative Instruments—Balance Sheet The fair value of the Company's derivative instruments is presented below.

millions		Gross Derivative Assets		Gross Derivative Liabilities	
Derivatives	**Balance Sheet Classification**	**December 31, 2011**	December 31, 2010	**December 31, 2011**	December 31, 2010
Commodity					
	Other Current Assets	**$ 924**	$ 444	**$ (353)**	$ (274)
	Other Assets	**150**	242	**(15)**	(56)
	Accrued Expenses	**5**	89	**(33)**	(131)
	Other Liabilities	**1**	26	**(17)**	(28)
		1,080	801	**(418)**	(489)
Interest Rate and Other					
	Accrued Expenses	**—**	—	**(391)**	(190)
	Other Liabilities	**—**	—	**(808)**	(45)
		—	—	**(1,199)**	(235)
Total Derivatives		**$ 1,080**	$ 801	**$ (1,617)**	$ (724)

Effect of Derivative Instruments—Statement of Income The realized and unrealized gain or loss amounts and classification of derivative instruments for the respective years ended December 31 are as follows:

millions		(Gain) Loss		
Derivatives	**Classification of (Gain) Loss Recognized**	**Realized**	**Unrealized**	**Total**
2011				
Commodity				
	Gathering, Processing, and Marketing Sales[(1)]	**$ 20**	**$ (12)**	**$ 8**
	(Gains) Losses on Commodity Derivatives, net	**(226)**	**(336)**	**(562)**
Interest Rate and Other				
	(Gains) Losses on Other Derivatives, net	**59**	**964**	**1,023**
Derivative (Gain) Loss, net		**$ (147)**	**$ 616**	**$ 469**
2010				
Commodity				
	Gathering, Processing, and Marketing Sales[(1)]	$ 3	$ (4)	$ (1)
	(Gains) Losses on Commodity Derivatives, net	(498)	(395)	(893)
Interest Rate and Other				
	(Gains) Losses on Other Derivatives, net	—	285	285
Derivative (Gain) Loss, net		$ (495)	$ (114)	$ (609)
2009				
Commodity				
	Gathering, Processing, and Marketing Sales[(1)]	$ (2)	$ 39	$ 37
	(Gains) Losses on Commodity Derivatives, net	(327)	735	408
Interest Rate				
	(Gains) Losses on Other Derivatives, net	(525)	(57)	(582)
Derivative (Gain) Loss, net		$ (854)	$ 717	$ (137)

(1) Represents the effect of marketing and trading derivative activities.

10. Derivative Instruments (Continued)

Credit-Risk Considerations The financial integrity of exchange-traded contracts is assured by NYMEX or the Intercontinental Exchange through systems of financial safeguards and transaction guarantees and is subject to nominal credit risk. Over-the-counter traded swaps, options, and futures contracts expose the Company to counterparty credit risk. The Company monitors the creditworthiness of its counterparties, establishes credit limits according to the Company's credit policies and guidelines, and assesses the impact of a counterparty's creditworthiness on fair value. The Company has the ability to require cash collateral or letters of credit to mitigate its credit-risk exposure. The Company has netting agreements with financial institutions that permit net settlement of gross commodity derivative assets against gross commodity derivative liabilities, and routinely exercises its contractual right to offset realized gains against realized losses when settling with derivative counterparties.

In addition, the Company has setoff agreements with certain financial institutions that may be exercised in the event of default and provide for contract termination and net settlement across all derivative types. At December 31, 2011, $749 million of the Company's $1.6 billion gross derivative liability balance, and at December 31, 2010, $394 million of the Company's $724 million gross derivative liability balance, would have been eligible for setoff against the Company's gross derivative asset balance in the event of default. Other than in the event of default, the Company does not net settle across commodity and interest-rate derivatives, as settlement timing differs.

Some of the Company's derivative instruments are subject to provisions that can require collateralization of the Company's obligations. However, most of the Company's derivative counterparties maintain secured positions with respect to the Company's derivative liabilities under the Company's $5.0 billion senior secured revolving credit facility ($5.0 billion Facility), the available capacity of which is sufficient to secure potential obligations to such counterparties.

Unsecured derivative obligations may require immediate settlement or full collateralization if certain credit-risk-related provisions are triggered, such as the Company's credit rating declining to a level below investment grade by major credit rating agencies. In June 2010, the Company's credit rating was downgraded from "Baa3" to "Ba1" by Moody's Investors Service (Moody's), which triggered credit-risk-related features with certain derivative counterparties, resulting in the Company posting additional collateral under its derivative instruments. No counterparties have requested termination or full settlement of derivative positions. At December 31, 2011 and 2010, the aggregate fair value of all derivative instruments with credit-risk-related contingent features for which a net liability position existed was $2 million (net of collateral) and $10 million (net of collateral), respectively, included in accrued expenses on the Company's Consolidated Balance Sheets.

10. Derivative Instruments (Continued)

Fair Value Fair value of futures contracts is based on quoted prices in active markets for identical assets or liabilities, which represent Level 1 inputs. Valuations of physical-delivery purchase and sale agreements, over-the-counter financial swaps, and commodity option collars are based on similar transactions observable in active markets and industry-standard models that primarily rely on market-observable inputs. Inputs used to estimate the fair value of swaps and options include market-price curves; contract terms and prices; credit-risk adjustments; and, for Black-Scholes option valuations, implied market volatility and discount factors. Inputs used to estimate fair value in industry-standard models are categorized as Level 2 inputs because substantially all assumptions and inputs are observable in active markets throughout the full term of the instruments.

The fair value of the Company's derivative financial assets and liabilities, by input level within the fair-value hierarchy, is presented below.

December 31, 2011

millions	Level 1	Level 2	Level 3	Netting[(1)]	Collateral	Total
Assets:						
Commodity derivatives						
Financial institutions	$ 3	$ 909	$ —	$ (323)	$ (52)	$ 537
Other counterparties	—	168	—	(51)	—	117
Total derivative assets	$ 3	$ 1,077	$ —	$ (374)	$ (52)	$ 654
Liabilities:						
Commodity derivatives						
Financial institutions	$ (4)	$ (375)	$ —	$ 361	$ 7	$ (11)
Other counterparties	—	(39)	—	13	—	(26)
Interest-rate and other derivatives	—	(1,199)	—	—	130	(1,069)
Total derivative liabilities	$ (4)	$ (1,613)	$ —	$ 374	$ 137	$ (1,106)

(1) Represents the impact of netting commodity derivative assets and liabilities with counterparties where the Company has the contractual right and intends to net settle.

10. Derivative Instruments (Continued)

December 31, 2010

millions	Level 1	Level 2	Level 3	Netting[(1)]	Collateral	Total
Assets:						
Commodity derivatives						
Financial institutions	$ 3	$ 557	$ —	$ (298)	$ (15)	$ 247
Other counterparties	—	241	—	(148)	—	93
Total derivative assets	$ 3	$ 798	$ —	$ (446)	$ (15)	$ 340
Liabilities:						
Commodity derivatives						
Financial institutions	$ (2)	$ (333)	$ —	$ 298	$ —	$ (37)
Other counterparties	—	(154)	—	148	—	(6)
Interest-rate and other derivatives	—	(235)	—	—	15	(220)
Total derivative liabilities	$ (2)	$ (722)	$ —	$ 446	$ 15	$ (263)

(1) Represents the impact of netting commodity derivative assets and liabilities with counterparties where the Company has the contractual right and intends to net settle.

11. Asset Retirement Obligations

The majority of Anadarko's AROs relate to the plugging of wells and the related abandonment of oil and gas properties. The following provides a rollforward of the Company's combined short- and long-term AROs. Liabilities settled include settlement payments for obligations, as well as obligations that were assumed by purchasers of divested properties. Revisions to estimated liabilities during the period relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives, and the expected timing of settlement.

millions	**2011**	2010
Carrying amount of asset retirement obligations at January 1	**$ 1,571**	$ 1,446
Liabilities incurred	**39**	88
Liabilities settled	**(68)**	(36)
Accretion expense	**100**	92
Revisions in estimated liabilities	**126**	(19)
Carrying amount of asset retirement obligations at December 31[(1)]	**$ 1,768**	$ 1,571

(1) At December 31, 2011 and 2010, short-term AROs of $31 million and $42 million, respectively, were presented on the Company's Consolidated Balance Sheets as accrued expenses.

12. Debt and Interest Expense

Debt Except for borrowings under the $5.0 billion Facility, all of the Company's outstanding debt is senior unsecured. See *Note 9—Investments* for disclosure regarding Anadarko's notes payable related to its ownership of certain noncontrolling mandatorily redeemable interests that are not included in the Company's reported debt balance and do not affect consolidated interest expense. The following presents the Company's outstanding debt and capital lease obligations at December 31, 2011 and 2010.

	December 31,	
millions	**2011**	2010
6.875% Senior Notes due 2011	**$ —**	$ 285
6.125% Senior Notes due 2012	**131**	131
5.000% Senior Notes due 2012	**39**	39
5.750% Senior Notes due 2014	**275**	275
7.625% Senior Notes due 2014	**500**	500
5.950% Senior Notes due 2016	**1,750**	1,750
6.375% Senior Notes due 2017	**2,000**	2,000
7.050% Debentures due 2018	**114**	114
6.950% Senior Notes due 2019	**300**	300
8.700% Senior Notes due 2019	**600**	600
6.950% Senior Notes due 2024	**650**	650
7.500% Debentures due 2026	**112**	112
7.000% Debentures due 2027	**54**	54
7.125% Debentures due 2027	**150**	150
6.625% Debentures due 2028	**17**	17
7.150% Debentures due 2028	**235**	235
7.200% Debentures due 2029	**135**	135
7.950% Debentures due 2029	**117**	117
7.500% Senior Notes due 2031	**900**	900
7.875% Senior Notes due 2031	**500**	500
Zero-Coupon Senior Notes due 2036	**2,360**	2,360
6.450% Senior Notes due 2036	**1,750**	1,750
7.950% Senior Notes due 2039	**325**	325
6.200% Senior Notes due 2040	**750**	750
7.730% Debentures due 2096	**61**	61
7.500% Debentures due 2096	**78**	78
7.250% Debentures due 2096	**49**	49
$5.0 billion Facility	**2,500**	—
WES borrowings	**500**	299
Total debt at face value	**$ 16,952**	$ 14,536
Net unamortized discounts and premiums[1]	**(1,722)**	(1,749)
Total borrowings	**$ 15,230**	$ 12,787
Capital lease obligation	**—**	226
Less: Current portion of long-term debt	**170**	291
Total long-term debt	**$ 15,060**	$ 12,722

(1) Unamortized discounts and premiums are amortized over the terms of the related debt.

12. Debt and Interest Expense (Continued)

In a 2006 private offering, Anadarko received $500 million of loan proceeds upon issuing the Zero-Coupon Senior Notes due 2036 (Zero Coupons). The Zero Coupons mature in 2036 and have an aggregate principal amount due at maturity of $2.4 billion, reflecting a yield to maturity of 5.24%. The holder has the right to cause the Company to repay an amount up to the then-accreted value of the outstanding Zero Coupons in October of each year starting in 2012. The Zero Coupons are classified as long-term debt on the Consolidated Balance Sheets based on the Company's ability and intent to refinance the obligations, if the holder requests repayment in 2012.

Fair Value The Company uses a market approach to determine fair value of its fixed-rate debt using observable market data, which results in a Level 2 fair-value measurement. The carrying amount of floating-rate debt approximates fair value as the interest rates are variable and reflective of market rates. As of December 31, 2011 and 2010, the estimated fair value of the Company's total long-term debt was $17.3 billion and $13.5 billion, respectively.

Debt Activity The following presents the Company's debt activity for 2011 and 2010.

millions	Carrying Value	Description
Balance at December 31, 2009	$ 12,748	
Issuances	2,000	6.375% Senior Notes due 2017
	745	6.200% Senior Notes due 2040
Borrowings	670	WES credit facility and term loan
Repayments[1]	(942)	6.750% Senior Notes due 2011
	(398)	6.875% Senior Notes due 2011
	(38)	6.125% Senior Notes due 2012
	(43)	5.000% Senior Notes due 2012
	(371)	WES credit facility
	(1,599)	Midstream Subsidiary Note due 2012
Other, net	15	Changes in debt premium or discount
Balance at December 31, 2010	$ 12,787	
Issuances	**494**	WES 5.375% Senior Notes due 2021
Borrowings	**570**	WES credit facility
	2,500	$5.0 billion Facility
Repayments[1]	**(869)**	WES credit facility and WES term loan
	(285)	6.875% Senior Notes due 2011
Other, net	**33**	Changes in debt premium or discount
Balance at December 31, 2011	**$ 15,230**	

(1) Debt repayment activity includes both scheduled repayments and retirements before scheduled maturity.

Capital Lease Obligation In the fourth quarter of 2010, a lease commenced for a floating production, storage, and offloading vessel (FPSO) for the Company's Jubilee field operations in Ghana. In December 2011, the Company and its partners in the Jubilee project purchased the FPSO, resulting in the cancellation of the capital lease obligation.

12. Debt and Interest Expense (Continued)

Anadarko Revolving Credit Facility and Letter of Credit Facility In September 2010, the Company entered into the $5.0 billion Facility maturing in September 2015, and terminated its $1.3 billion revolving credit agreement, scheduled to mature in 2013. During the third quarter of 2011, the Company entered into an agreement with a financial institution to provide up to $400 million of letters of credit (LOC Facility). Compensating balances deposited with the financial institution provide for reduced fees under the LOC Facility. These compensating balances may be withdrawn at any time, resulting in higher fees. Cash and cash equivalents include $328 million of demand deposits serving as compensating balances for outstanding letters of credit at December 31, 2011. The LOC Facility also requires the Company to maintain a senior debt revolving credit facility with minimum commitments of at least $1.0 billion and the availability to issue letters of credit of at least $400 million.

In August 2011, the Company amended the $5.0 billion Facility to reduce the maintenance costs and to lower the interest rates under the facility. Borrowings under the $5.0 billion Facility bear interest at LIBOR plus an applicable margin ranging from 1.25% to 2.50%, depending on the Company's credit rating, or rates at a margin above the one-month LIBOR, the federal funds rate, or prime rates offered by certain designated banks. The $5.0 billion Facility had outstanding borrowings of $2.5 billion at a rate of 1.79%, with available borrowing capacity of $2.1 billion ($5.0 billion maximum capacity, less $2.5 billion of outstanding borrowings and $400 million of letter-of-credit capacity maintained pursuant to the terms of the LOC Facility) at December 31, 2011.

Obligations incurred under the $5.0 billion Facility, as well as obligations Anadarko has to lenders or their affiliates pursuant to certain derivative instruments (as discussed in *Note 10—Derivative Instruments*), are guaranteed by certain of the Company's wholly owned domestic subsidiaries, and are secured by a perfected first-priority security interest in certain exploration and production assets located in the United States and 65% of the capital stock of certain wholly owned foreign subsidiaries. The Company was in compliance with all applicable covenants and there were no restrictions on its ability to utilize the available capacity of the $5.0 billion Facility.

WES Revolving Credit Facility In March 2011, WES entered into a five-year, $800 million senior unsecured revolving credit facility (RCF), which amended and restated the $450 million senior unsecured revolving credit facility. The $800 million RCF matures in March 2016 and bears interest at LIBOR plus an applicable margin ranging from 1.30% to 1.90%, or rates at a margin above the one-month LIBOR, the federal funds rate, or prime rates offered by certain designated banks. WES was in compliance with all covenants contained in the RCF, had no outstanding borrowings under the RCF, and had the full $800 million of RCF borrowing capacity available at December 31, 2011.

Scheduled Maturities Total principal amount of debt maturities for the five years ending December 31, 2016 are shown below and exclude amounts attributable to the potential repayment of the outstanding Zero Coupons that may be put by the holder to the Company annually, starting in 2012, as discussed above.

millions	**Principal Amount of Debt Maturities**
2012	$ 170
2013	—
2014	775
2015	2,500
2016	1,750

12. Debt and Interest Expense (Continued)

Interest Expense The following summarizes the amounts included in interest expense.

	Years Ended December 31,		
millions	**2011**	2010	2009
Current debt, long-term debt, and other[(1)]	**$ 986**	$ 871	$ 773
(Gain) loss on early debt retirements and commitment termination[(2)]	**—**	112	(2)
Capitalized interest	**(147)**	(128)	(69)
Interest expense	**$ 839**	$ 855	$ 702

(1) Included in 2009 is the reversal of the $78 million liability for unpaid interest related to the Deepwater Royalty Relief Act (DWRRA) dispute. See *Note 16—Contingencies*.

(2) Loss on early debt retirements in 2010 is the result of repurchasing $1.4 billion aggregate principal amount of debt due 2011 and 2012.

13. Stockholders' Equity

Common Stock In August 2011, the Company terminated a $5.0 billion share-repurchase program under which shares could be repurchased either in the open market or through privately negotiated transactions.

In May 2009, Anadarko completed a public offering of 30 million shares of common stock at $45.50 per share. After deducting the underwriting discount and other offering costs of $28 million, net proceeds of approximately $1.3 billion were used for general corporate purposes, including capital expenditures.

millions	**2011**	2010	2009
Shares of common stock issued			
Shares at January 1	**513**	509	476
Issuance of common stock	**—**	—	30
Exercise of stock options	**1**	2	1
Issuance of restricted stock	**2**	2	2
Shares at December 31	**516**	513	509
Shares of common stock held in treasury			
Shares at January 1	**17**	16	16
Shares received for restricted stock vested and options exercised	**1**	1	—
Shares at December 31	**18**	17	16
Shares of common stock outstanding at December 31	**498**	496	493

13. Stockholders' Equity (Continued)

Shares of common stock issued and shares of common stock held in treasury presented above include four million shares held by the Anadarko Petroleum Corporation Executives and Directors Benefits Trust, a grantor trust associated with the Company's obligations under certain of its pension and deferred-compensation plans.

The reconciliation between basic and diluted EPS attributable to common stockholders is as follows:

	Years Ended December 31,		
millions except per-share amounts	**2011**	2010	2009
Net income (loss):			
Net income (loss) attributable to common stockholders	**$ (2,649)**	$ 761	$ (135)
Less: Distributions on participating securities	**—**	1	—
Less: Undistributed income allocated to participating securities	**—**	4	—
Basic	**$ (2,649)**	$ 756	$ (135)
Diluted	**$ (2,649)**	$ 756	$ (135)
Shares:			
Average number of common shares outstanding—basic	**498**	495	480
Dilutive effect of stock options and performance-based stock awards	**—**	2	—
Average number of common shares outstanding—diluted	**498**	497	480
Excluded[(1)]	**12**	6	14
Net income (loss) per common share:			
Basic	**$ (5.32)**	$ 1.53	$ (0.28)
Diluted	**$ (5.32)**	$ 1.52	$ (0.28)
Dividends per common share	**$ 0.36**	$ 0.36	$ 0.36

(1) Inclusion of the average shares for these awards would have an anti-dilutive effect.

14. Share-Based Compensation

At December 31, 2011, 15 million shares of the 35 million shares of Anadarko common stock originally authorized for awards under active share-based compensation plans remained available for future issuance. The Company generally issues new shares to satisfy awards under employee share-based payment plans. The number of shares available is reduced by awards granted. A summary of share-based compensation cost is presented below.

millions	Years Ended December 31, 2011	2010	2009
Compensation Cost:			
Equity-Classified Awards:			
Restricted stock	**$ 80**	$ 103	$ 138
Stock options	**51**	45	36
Performance-based share awards and other	**1**	3	11
Total Equity-Classified Award Compensation Expense	**132**	151	185
Liability-Classified Awards:			
Value Creation Plan	**26**	—	104
Performance-based unit awards	**28**	36	17
Other performance-based awards	**28**	8	—
Other	**1**	2	3
Total Liability-Classified Award Compensation Expense	**83**	46	124
Total Compensation Expense, pretax	**$ 215**	$ 197	$ 309
Income tax benefit	**$ 78**	$ 72	$ 112

For 2011, 2010, and 2009, $(15) million, $26 million, and $12 million, respectively, in excess tax benefits related to share-based compensation were included in cash flows from financing activities. Cash received from stock option exercises for 2011, 2010, and 2009 was $45 million, $78 million, and $22 million, respectively.

Equity-Classified Awards

Restricted Stock Certain employees may be granted restricted stock in the form of restricted stock awards or restricted stock units. Restricted stock is subject to forfeiture restrictions and cannot be sold, transferred, or disposed of during the restriction period. The holders of restricted stock awards have the same rights as a stockholder of the Company with respect to such shares, including the right to vote and receive dividends or other distributions paid with respect to the shares. A restricted stock unit is equivalent to a restricted stock award except that unit holders receive cash dividend equivalents during the restriction period and do not have the right to vote the units. Restricted stock vests over service periods ranging from the date of grant up to four years and is not considered issued and outstanding until it vests.

Nonemployee directors are granted deferred shares that are held in a grantor trust by the Company until payable, generally when the director ceases to serve on the Board of Directors. Directors may receive these shares in a lump-sum payment or in annual installments.

14. Share-Based Compensation (Continued)

A summary of restricted stock activity is presented below.

	Shares *(millions)*	Weighted-Average Grant-Date Fair Value *(per share)*
Non-vested at January 1, 2011	2.76	$ 56.44
Granted	1.34	$ 81.19
Vested	(1.56)	$ 56.53
Forfeited	(0.07)	$ 65.88
Non-vested at December 31, 2011	2.47	$ 69.55

The weighted-average grant-date fair value per share of restricted stock granted during 2010 and 2009 was $68.51 and $40.65, respectively. The total fair value of restricted shares vested during 2011, 2010, and 2009 was $124 million, $122 million, and $122 million, respectively, based on the market price at the vesting date. At December 31, 2011, $119 million of total unrecognized compensation cost related to restricted stock is expected to be recognized over a weighted-average remaining service period of 2.0 years.

Stock Options Certain employees may be granted options to purchase shares of Anadarko common stock with an exercise price equal to, or greater than, the fair market value of Anadarko common stock on the date of grant. These stock options vest over service periods ranging from three to four years from the date of grant and will terminate at the earlier of the date of exercise, or seven years from the date of grant.

Non-employee directors may be granted nonqualified stock options with an exercise price equal to the fair market value of Anadarko common stock on the date of grant. These stock options vest over a one-year service period from the date of grant and terminate at the earlier of the date of exercise, or ten years from the date of grant.

The fair value of stock option awards is determined using the Black-Scholes option-pricing model. The expected life of an option is estimated based on historical exercise behavior. Expected forfeiture rates are estimated based on historical forfeiture rates. Volatility assumptions are estimated based on expectations of volatility over the expected life of an option as indicated by historical and implied volatility. Risk-free interest rates are based on the U.S. Treasury rate for a term commensurate with the expected life of an option. The dividend yield is based on a 12-month average dividend yield, taking into account the Company's expected dividend policy over the expected life of an option. The Company used the following weighted-average assumptions to estimate the fair value of stock options granted during 2011, 2010, and 2009.

	2011	2010	2009
Expected option life—years	**4.8**	4.9	4.9
Volatility	**42.0%**	43.9%	46.3%
Risk-free interest rate	**1.5%**	2.0%	1.9%
Dividend yield	**0.5%**	0.7%	0.8%

14. Share-Based Compensation (Continued)

A summary of stock option activity is presented below.

	Shares *(millions)*	Weighted-Average Exercise Price *(per share)*	Weighted-Average Remaining Contractual Term *(years)*	Aggregate Intrinsic Value *(millions)*
Outstanding at January 1, 2011	9.55	$ 49.15		
Granted	1.55	$ 82.39		
Exercised	(1.12)	$ 40.25		
Forfeited or expired	(0.11)	$ 58.08		
Outstanding at December 31, 2011	9.87	$ 55.27	4.46	$ 217.2
Vested or expected to vest at December 31, 2011	4.04	$ 65.36	5.50	$ 53.3
Exercisable at December 31, 2011	5.68	$ 47.91	3.70	$ 161.6

The weighted-average grant-date fair value per option of stock options granted during 2011, 2010, and 2009 was $29.77, $26.44, and $15.23, respectively. The total intrinsic value of stock options exercised during 2011, 2010, and 2009 was $45 million, $62 million, and $24 million, respectively, based on the difference between the market price at the exercise date and the exercise price. At December 31, 2011, $71 million of total unrecognized compensation cost related to stock options is expected to be recognized over a weighted-average period of 2.0 years.

Performance-Based Share Awards Certain officers of the Company were provided Performance Unit Award Agreements with performance periods ranging from one to three years. The number of shares of common stock awarded under these agreements is based on a comparison of the Company's TSR to the TSR of a predetermined group of peer companies over the specified performance period. The agreements provide for issuance of up to a maximum of 934,424 shares of Anadarko common stock. Through December 31, 2011, a total of 521,258 shares were granted, with 386,574 of these shares issued and 134,684 shares deferred pursuant to the agreements. The fair value of the performance-based share awards issued during 2011, 2010, and 2009 was $6 million, $17 million, and $1 million, respectively, based on the market price at the date issued. At December 31, 2011, the Company had no unrecognized compensation cost related to these awards.

Liability-Classified Awards

Value Creation Plan As a part of its employee compensation program, the Company offers an incentive compensation program that generally provides *non-officer* employees the opportunity to earn cash bonus awards based on the Company's TSR for the year, compared to the TSR of a predetermined group of peer companies. At December 31, 2011, 2010, and 2009, the Company had accrued $25 million, zero, and $105 million, respectively, for the 2011, 2010, and 2009 performance periods, respectively.

14. Share-Based Compensation (Continued)

Performance-Based Unit Awards Certain officers of the Company were provided Performance Unit Award Agreements with two- and three-year performance periods. The vesting of these units is based solely on comparing the Company's TSR to the TSR of a predetermined group of peer companies over the specified performance period. Each performance unit represents the value of one share of the Company's common stock. At the end of each performance period, the value of the vested performance units, if any, is paid in cash. During 2011, $25 million was paid related to vested performance units. At December 31, 2011, the Company's liability under Performance Unit Award Agreements was $53 million, with $27 million of total estimated unrecognized compensation cost related to these awards expected to be recognized over a weighted-average, remaining performance period of 1.6 years.

Other Performance-Based Awards Certain officers of the general partner of WES were awarded general partner (GP) Unit Appreciation Rights (UARs) pursuant to the Western Gas Holdings, LLC Equity Incentive Plan. No awards have been granted subsequent to 2010. The vesting restrictions on the UARs lapse over defined performance periods, and the value of vested awards is paid in cash upon exercise by the holder, which is permitted based on defined events. The fair value of the UARs is re-measured periodically based on the estimated fair value of WES's GP, calculated using a discounted cash flow methodology. At December 31, 2011, the liability attributable to the UARs was $37 million, with $6 million of total estimated unrecognized compensation cost related to these awards expected to be recognized over a weighted-average remaining period of 1.4 years.

15. Commitments

Operating Leases The Company had $2.9 billion in long-term drilling rig commitments that satisfy operating lease criteria. The Company also has various commitments under non-cancelable operating lease agreements of $678 million for production platforms and equipment, buildings, facilities, compressors, and aircraft. These operating leases expire at various dates through 2026. Certain of these operating leases contain residual value guarantees at the end of the lease term, totaling $104 million at December 31, 2011; however, no liability has been accrued for residual value guarantees. Future minimum lease payments under operating leases at December 31, 2011 were as follows:

millions	Operating Leases
2012	$ 696
2013	523
2014	630
2015	547
2016	414
Later years	812
Total future minimum lease payments	$ 3,622

Total rent expense, net of sublease income, amounted to $143 million in 2011, $154 million in 2010, and $188 million in 2009. Total rent expense includes contingent rent expense related to processing fees of $21 million, $20 million, and $39 million in 2011, 2010, and 2009, respectively.

15. Commitments (Continued)

Drilling Rig Commitments Anadarko has entered into various agreements to secure drilling rigs necessary to execute its drilling plans over the next several years. The table of future minimum lease payments above includes approximately $2.7 billion related to six offshore drilling vessels and $217 million related to certain contracts for onshore U.S. drilling rigs. Lease payments associated with the drilling of exploratory wells and development wells, net of amounts billed to partners, will initially be capitalized as a component of oil and gas properties, and either depreciated in future periods or written off as exploration expense.

Spar Platform and Production Vessel Leases Anadarko has operating leases related to certain spar platforms in the Gulf of Mexico. The table of future minimum lease payments above includes approximately $395 million for these agreements. These agreements also contain residual value guarantees totaling $37 million at the end of the lease periods.

Other Commitments In the normal course of business, the Company enters into other contractual agreements to purchase natural gas or crude oil, pipeline capacity, storage capacity, utilities, and other services. At December 31, 2011, aggregate future payments under these contracts totaled $6.8 billion, of which $1.6 billion is expected to be paid in 2012, $917 million in 2013, $839 million in 2014, $726 million in 2015, $607 million in 2016, and $2.1 billion thereafter.

16. Contingencies

The following discussion of the Company's contingencies excludes discussion related to the Deepwater Horizon events. See *Note 2—Deepwater Horizon Events*.

General The Company is a defendant in a number of lawsuits and is involved in governmental proceedings and regulatory controls arising in the ordinary course of business, including, but not limited to, personal injury claims, title disputes, royalty claims, contract claims, oil-field contamination claims, and environmental claims, including claims involving assets owned by predecessors of acquired companies. The Company had accrued $342 million and $114 million at December 31, 2011 and 2010, respectively, related to litigation contingencies. Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. At December 31, 2011 and 2010, the Company's Consolidated Balance Sheets include liabilities of $92 million and $96 million, respectively, for remediation and reclamation obligations. The ultimate outcome and impact on the Company cannot be predicted with certainty; however, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's consolidated financial position, results of operations, or cash flows.

16. Contingencies (Continued)

Tronox Litigation In January 2009, Tronox Incorporated (Tronox), a former subsidiary of Kerr-McGee Corporation (Kerr-McGee), which is a current subsidiary of Anadarko, and certain of Tronox's subsidiaries filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code (the Bankruptcy) in the U.S. Bankruptcy Court for the Southern District of New York (Bankruptcy Court). Subsequently, in May 2009, Tronox and certain of its affiliates filed a lawsuit against Anadarko and Kerr-McGee asserting a number of claims, including claims for actual and constructive fraudulent conveyance (Adversary Proceeding). Tronox alleges, among other things, that it was insolvent or undercapitalized at the time it was spun off from Kerr-McGee and seeks, among other things, to recover damages, including interest, in excess of $14.5 billion from Kerr-McGee and Anadarko, as well as litigation fees and costs. Anadarko and Kerr-McGee moved to dismiss the complaint in its entirety. In March 2010, the Bankruptcy Court issued an opinion granting in part and denying in part Anadarko's and Kerr-McGee's motion to dismiss the complaint. Notably, the Bankruptcy Court dismissed, with prejudice, Tronox's request for punitive damages relating to the fraudulent-conveyance claims. The Bankruptcy Court granted Tronox leave to replead certain of its common law claims, and Tronox filed an amended complaint in April 2010. In May 2010, Anadarko and Kerr-McGee moved to dismiss certain claims in the amended complaint. In May 2011, the Bankruptcy Court dismissed two claims against Anadarko for conspiracy and aiding and abetting, and declined to dismiss a breach of fiduciary duty claim against Kerr-McGee. In August 2011, Tronox filed a motion for partial summary judgment on the issue of whether damages in the Adversary Proceeding are limited to the amount of allowed creditor claims filed in the Bankruptcy. Kerr-McGee and Anadarko filed a response and cross-motion in September 2011 seeking a ruling that Sections 544, 548, and 550 of the Bankruptcy Code limit Tronox's potential recovery to the value of valid, unpaid creditor claims. In January 2012, the Court granted Tronox's motion for summary judgment in part and held that Section 550 of the Bankruptcy Code does not impose a cap on Tronox's potential damages for fraudulent transfer claims. The Court denied Tronox's motion in part, to the extent Tronox sought a ruling that there are no other limitations on fraudulent conveyance damages. The Court stated that the appropriate measure of damages should only be determined after trial. The parties engaged in mediation in January 2012, but were unable to reach a resolution.

The U.S. government was granted authority to intervene in the Adversary Proceeding, and it has asserted separate claims against Anadarko and Kerr-McGee under the Federal Debt Collection Procedures Act. Anadarko and Kerr-McGee have moved to dismiss the claims of the U.S. government, but that motion has been stayed by the Bankruptcy Court.

In August 2010, the Bankruptcy Court entered a Stipulation and Agreed Order among Tronox, Anadarko, and Kerr-McGee authorizing the rejection of the Master Separation Agreement (together with all annexes, related agreements, and ancillary agreements to it, the MSA). Anadarko and Kerr-McGee filed Proofs of Claim, which included claims for damages arising from the MSA rejection. In January 2011, the Bankruptcy Court entered a Stipulation and Agreed Order approving a settlement of Anadarko and Kerr-McGee's rejection damage claims against Tronox. The settlement provided Anadarko a general unsecured claim against Tronox. In February 2011, in settlement of its claim, Anadarko received shares of Tronox stock, which were assigned to a financial institution in exchange for $46 million, included as a credit to general and administrative expenses in the Company's Consolidated Statements of Income for the year ended December 31, 2011. The Company will continue to monitor the impact that the rejection of the MSA may have on other litigation and other proceedings, including the Adversary Proceeding, and will assess the impact of future events on the Company's consolidated financial position, results of operations, and cash flows.

16. Contingencies (Continued)

In February 2011, in accordance with Chapter 11 of the U.S. Bankruptcy Code, Tronox emerged from bankruptcy pursuant to an August 2010 Bankruptcy Court approved Plan of Reorganization (Plan). The terms of the Plan, which were confirmed by the Bankruptcy Court in the third quarter of 2010, contemplate that the claims of the U.S. government (together with other federal, state, local, or tribal governmental entities having regulatory authority or responsibilities for environmental laws, the Governmental Entities) related to Tronox's environmental liabilities will be settled through certain environmental response trusts and a litigation trust (Anadarko Litigation Trust). The Plan provides that the Governmental Entities will receive, among other things, 88% of the proceeds from the Adversary Proceeding. Additionally, certain creditors asserting tort claims against Tronox may receive, among other things, 12% of the proceeds from the Adversary Proceeding. Certain documents central to the Plan and the Adversary Proceeding were approved by the Bankruptcy Court in the fourth quarter of 2010 and in February 2011, including the Environmental Claims Settlement Agreement, the Tort Claims Trust Agreement, the Environmental Response Trust Agreement, and the Anadarko Litigation Trust Agreement (ALTA). In accordance with the Plan, the Adversary Proceeding will be prosecuted by the Anadarko Litigation Trust. Pursuant to the ALTA, the Anadarko Litigation Trust was "deemed substituted" for Tronox in the Adversary Proceeding as the party in such litigation. For purposes of this Form 10-K, references to "Tronox" after February 2011 refer to the Anadarko Litigation Trust.

Discovery, motion practice, and mediation are ongoing in the Adversary Proceeding. The Company's current estimated loss related to final disposition of the Adversary Proceeding is $250 million, and the Company has recorded a liability for this amount at December 31, 2011. As the Adversary Proceeding progresses, it is reasonably possible for the Company's current estimate of probable loss related to this matter to change, perhaps materially, because the amount of potential damages depends on circumstances that have not yet occurred, including the outcome of expert testimony and certain trial and pretrial determinations to be made by the Bankruptcy Court. The Company intends to vigorously defend the claims asserted in these proceedings.

In addition, in July 2009, a consolidated class action complaint was filed in the New York District Court on behalf of purported purchasers of Tronox's equity and debt securities between November 21, 2005, and January 12, 2009 (Class Period), against Anadarko, Kerr-McGee, several former Kerr-McGee officers and directors, several former Tronox officers and directors, and Ernst & Young LLP (Securities Case). The complaint alleges causes of action arising under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 (Exchange Act) for purported misstatements and omissions regarding, among other things, Tronox's environmental-remediation and tort-claim liabilities. The plaintiffs allege, among other things, that these purported misstatements and omissions are contained in certain of Tronox's public filings, including filings made in connection with Tronox's initial public offering. The plaintiffs seek an unspecified amount of compensatory damages, including interest thereon, as well as litigation fees and costs. Anadarko, Kerr-McGee, and other defendants moved to dismiss the consolidated class action complaint and in August 2010 moved to dismiss an amended consolidated class action complaint that had been filed in July 2010. The New York District Court issued the second of two opinions and orders on the motions (Orders). Following the Orders, only the plaintiffs' Section 20(a) claims under the Exchange Act remain against Anadarko and Kerr-McGee. The plaintiffs' claims against Anadarko are limited to the period beginning on August 10, 2006, through the end of the Class Period. In August 2011, plaintiffs filed a motion for class certification. The defendants in the Securities Case filed briefs in opposition to class certification in September 2011. In January 2012, the Court entered a Stipulation and Order pursuant to which plaintiffs agreed to withdraw their motion for class certification without prejudice to resubmit the motion as previously filed.

Based on the Company's assessment of the current status and merits of the Securities Case, the Company does not consider a loss related to litigation of these matters to be probable. This conclusion considers that the court has not certified a class, no fact discovery has occurred, and no dispositive motions have been filed by the litigants. As the Securities Case progresses, it is reasonably possible the Company's assessment as to its potential loss could change, perhaps materially. The Company carries Directors' and Officers' liability insurance and has notified its insurers as to the status of this litigation. The Company will continue to vigorously defend itself, its officers, and its directors in these proceedings.

16. Contingencies (Continued)

Other Litigation SM Energy alleged that the Company breached a Joint Exploration Agreement (JEA) originally executed between Anadarko and TXCO Energy Corp. (TXCO) in March 2008 relating to an oil and gas development project in Maverick, Dimmitt, Webb, and LaSalle Counties in the Eagleford shale in South Texas. The parties entered into binding arbitration on the matter, and in November 2011, the arbitration panel rendered a final decision in favor of the Company.

In December 2008, Anadarko sold its interest in the Peregrino heavy-oil field offshore Brazil. The Company is currently litigating a dispute with the Brazilian tax authorities regarding the tax rate applicable to the transaction. Currently, $182 million, the amount of tax in dispute, resides in a judicially controlled Brazilian bank account, pending final resolution of the matter.

In July 2009, the lower judicial court ruled in favor of the Brazilian tax authorities. The Company appealed this decision to the Brazilian Regional courts, which upheld the lower court's ruling in favor of the Brazilian tax authorities in December 2011. The Company will file simultaneous appeals to the Brazilian Superior court and the Brazilian Supreme court. The Brazilian Supreme court is not required to hear the case.

The Company believes that it will more likely than not prevail in Brazilian courts. Therefore, no tax liability has been recorded for Peregrino divestiture-related litigation as of December 31, 2011. The Company continues to vigorously defend itself in Brazilian courts.

Deepwater Drilling Moratorium and Other Related Matters As a result of the moratorium on drilling in the Gulf of Mexico between mid-May 2010 and mid-October 2010 (Moratorium) and additional inspection and safety requirements issued by the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE), previously known as the Minerals Management Service (MMS), in May and June 2010, the Company provided notification of force majeure to drilling contractors of four of the Company's contracted deepwater rigs in the Gulf of Mexico. Some of the contracts have provisions that authorize contract termination by either party if force majeure conditions continue for a specified number of consecutive days.

In June 2010, the Company gave written notice of termination to the drilling contractor of a rig placed in force majeure in May 2010, and filed a lawsuit in the U.S. District Court for the Southern District of Houston, Texas (Houston, Texas District Court) against the drilling contractor seeking a judicial declaration that the Company's interpretation of the drilling contract was correct and that the contract terminated on June 19, 2010. The drilling contractor filed an Original Answer in July 2010 denying the Moratorium constituted a force majeure event and asserted that Anadarko had breached the drilling contract. If the Company does not prevail in its claim, the Company could be obligated to pay the rig contract rate from the contract-termination date through March 2011, the end of the original contract term. The disputed rental for the contract period is $116 million; however, any potential damages would be reduced by, among other things, amounts resulting from the drilling contractor's ability to mitigate damages by leasing the drilling rig to another third party, as well as cost savings realized by the drilling contractor as a result of not operating the drilling rig for the entire original contract period. The Company continues to vigorously defend its position, and will participate with the drilling contractor in court-ordered mediation in February 2012.

Deepwater Royalty Relief Act In 1995, the U.S. Congress passed the Deepwater Royalty Relief Act (DWRRA) to stimulate exploration and production of oil and natural gas by providing relief from the obligation to pay royalties on certain federal leases located in the deep waters of the Gulf of Mexico. The Company currently owns interests in several deepwater Gulf of Mexico leases. After the passage of the DWRRA, the MMS (renamed the BOEMRE as discussed above) inserted price thresholds into leases issued in 1996, 1997, and 2000 that effectively eliminated the DWRRA royalty relief if these price thresholds were exceeded.

16. Contingencies (Continued)

In January 2006, the DOI issued an order (2006 Order) to Kerr-McGee Oil and Gas Corporation (KMOG), a subsidiary of Kerr-McGee, to pay oil and gas royalties and accrued interest on KMOG's deepwater Gulf of Mexico production associated with eight 1996, 1997, and 2000 leases, for which KMOG considered royalties to be suspended under the DWRRA. KMOG successfully appealed the 2006 Order, and the DOI's petition for a writ of certiorari with the U.S. Supreme Court was denied on October 5, 2009.

In 2009, based on the U.S. Supreme Court's denial of the DOI's petition for review by the court, Anadarko reversed its $657 million liability for accrued royalties on leases listed in the 2006 Order, similar orders to pay issued in 2008 and 2009, and other deepwater Gulf of Mexico leases with similar price-threshold provisions. The Company's accrued liability of $657 million related to royalties on production from January 2003 through September 2009, and included $165 million related to pre-acquisition contingencies recorded as part of the Company's 2006 acquisition of Kerr-McGee. In addition, the Company reversed its $78 million accrued liability for interest on these unpaid royalty amounts, substantially all of which related to post-acquisition periods.

The MMS issued two additional orders to Anadarko in 2008 and 2009 to pay "past-due" royalties and interest covering several deepwater Gulf of Mexico leases. Anadarko filed administrative appeals with the MMS for the 2008 and 2009 orders (which were stayed pending a final non-appealable judgment relating to the 2006 Order). As a result of the Supreme Court's denial of certiorari, the MMS notified Anadarko on February 25, 2010 that the 2008 and 2009 orders had been withdrawn.

Guarantees and Indemnifications Under the terms of the MSA entered into between Kerr-McGee and Tronox, Kerr-McGee agreed to reimburse Tronox for 50% of certain qualifying environmental-remediation costs incurred and paid by Tronox and its subsidiaries before November 28, 2012, subject to certain limitations and conditions. The reimbursement obligation under the MSA was limited to a maximum aggregate reimbursement of $100 million. During 2010, the Company reversed to non-operating income a $95 million liability recorded for this reimbursement obligation as a result of a court-authorized rejection of the MSA. See *Tronox Litigation* section of this note.

The Company also provides certain indemnifications in relation to asset dispositions. These indemnifications typically relate to disputes, litigation, or tax matters existing at the date of disposition. No material liabilities were recorded for any such indemnifications at December 31, 2011.

17. Other Taxes

Taxes incurred, other than income taxes, are as follows:

	Years Ended December 31,		
millions	**2011**	2010	2009
Production and severance	**$ 1,094**	$ 770	$ 523
Ad valorem	**265**	219	189
Other	**133**	79	34
Total	**$ 1,492**	$ 1,068	$ 746

17. Other Taxes (Continued)

In 2006, the Algerian parliament approved legislation and implementing regulations establishing an exceptional profits tax on foreign companies' Algerian oil production. These provisions provide for an exceptional profits tax imposed on gross production at rates of taxation ranging from 5% to 50% based on average daily production volumes for each calendar month in which the price of Brent crude averages over $30 per barrel, retroactively effective to August-2006 production. Exceptional profits tax applies to the full value of production rather than to the production value in excess of $30 per barrel. On this measurement basis, the Company recognized production tax expense of $680 million, $508 million, and $379 million for 2011, 2010, and 2009, respectively.

In response to the Algerian government's imposition of the exceptional profits tax, the Company has notified Sonatrach of its disagreement with the collection of the exceptional profits tax. The Company believes that the Production Sharing Agreement (PSA) provides fiscal stability through several provisions that require Sonatrach to pay all taxes and royalties. To facilitate discussions between the parties in an effort to resolve the dispute, in October 2007 the Company initiated a conciliation proceeding on the exceptional profits tax as provided in the PSA. Any recommendation issued by a conciliation board (Conciliation Board) arising out of the conciliation proceeding is non-binding on the parties. The Conciliation Board issued its non-binding recommendation in November 2008. In February 2009, the Company initiated arbitration against Sonatrach with regard to the exceptional profits tax. In accordance with the terms of the PSA, a notice of arbitration was submitted to Sonatrach. The arbitration hearing on the merits of the claims presented by Anadarko was held in June 2011. Any decision issued by the arbitration panel is binding on the parties. Although the Company cannot reasonably determine the timing of a decision by the arbitration panel, the Company anticipates a decision in the near term.

18. Income Taxes

Components of income tax expense (benefit) are as follows:

	Years Ended December 31,		
millions	**2011**	2010	2009
Current			
Federal	**$ (381)**	$ 305	$ (233)
State	**1**	18	(13)
Foreign	**977**	628	409
Total	**597**	951	163
Deferred			
Federal	**(1,470)**	(72)	(25)
State	**(68)**	(11)	(91)
Foreign	**85**	(48)	(52)
Total	**(1,453)**	(131)	(168)
Total income tax expense (benefit)	**$ (856)**	$ 820	$ (5)

18. Income Taxes (Continued)

Total income taxes differed from the amounts computed by applying the U.S. federal statutory income tax rate to income (loss) before income taxes. The sources of these differences are as follows:

	Years Ended December 31,		
millions except percentages	**2011**	2010	2009
Income (loss) before income taxes			
Domestic	**$ (5,416)**	$ 855	$ (660)
Foreign	**1,992**	786	552
Total	**$ (3,424)**	$ 1,641	$ (108)
U.S. federal statutory tax rate	**35%**	35%	35%
Tax computed at the U.S. federal statutory rate	**$ (1,198)**	$ 574	$ (38)
Adjustments resulting from:			
State income taxes (net of federal income tax benefit)	**(44)**	5	(68)
Foreign tax rate differential and valuation allowances	**58**	115	46
Non-deductible Algerian exceptional profits tax	**258**	193	144
U.S. tax on foreign income inclusions and distributions	**20**	22	119
Excess U.S. foreign tax credit generated	**—**	—	(8)
U.S. tax impact from losses and restructuring of foreign operations	**(24)**	(48)	(94)
Net changes in uncertain tax positions	**8**	28	(110)
Federal manufacturing deduction	**—**	(23)	19
Items resulting from business acquisitions	**19**	—	—
Other—net	**47**	(46)	(15)
Total income tax expense (benefit)	**$ (856)**	$ 820	$ (5)
Effective tax rate	**25%**	50%	5%

Certain tax effects related to internal restructuring of certain foreign and domestic operations have been recorded to other long-term assets or other long-term liabilities and are being recognized in the Consolidated Statements of Income as income tax expense (benefit) over the estimated life of the related properties. During 2011, 2010, and 2009, $55 million, $42 million, and $54 million, respectively, of the net liabilities recorded in prior years were reversed to income tax benefit. At December 31, 2011 and 2010, the balance related to the restructuring of certain foreign and domestic operations was $10 million in other long-term assets and $51 million in other long-term liabilities, respectively.

Components of total deferred taxes are as follows:

	December 31,	
millions	**2011**	2010
Federal	**$ (7,916)**	$ (9,365)
State, net of federal	**(252)**	(297)
Foreign	**(173)**	(88)
Total deferred taxes	**$ (8,341)**	$ (9,750)

18. Income Taxes (Continued)

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets (liabilities) are as follows:

	December 31,	
millions	**2011**	2010
Net current deferred tax assets	**$ 138**	$ 78
Net long-term deferred tax assets	**—**	33
Oil and gas exploration and development operations	**(8,187)**	(8,577)
Mineral operations	**(407)**	(414)
Midstream and other depreciable properties	**(1,264)**	(1,314)
Other	**(1)**	(49)
Gross long-term deferred tax liabilities	**(9,859)**	(10,354)
Oil and gas exploration and development costs	**127**	253
Net operating loss carryforward	**1,071**	311
Foreign tax credit carryforward	**119**	11
Other	**618**	372
Gross long-term deferred tax assets	**1,935**	947
Less: valuation allowances on deferred tax assets not expected to be realized	**(555)**	(454)
Net long-term deferred tax assets	**1,380**	493
Net long-term deferred tax liabilities	**(8,479)**	(9,861)
Total deferred taxes	**$ (8,341)**	$ (9,750)

Changes to valuation allowances, due to changes in judgment regarding the future realizability of deferred tax assets, were a decrease of $17 million and an increase of $24 million for 2011 and 2010, respectively. Changes in the balance of valuation allowances on deferred tax assets are as follows:

millions	**2011**	2010	2009
Balance at January 1	**$ (454)**	$ (418)	$ (509)
Additions	**(138)**	(49)	(3)
Reductions	**37**	13	94
Balance at December 31	**$ (555)**	$ (454)	$ (418)

Taxes receivable (payable) related to income tax expense (benefit) are as follows:

		December 31,	
millions	**Balance Sheet Classification**	**2011**	2010
Income taxes receivable	Accounts receivable—other	**$ 597**	$ 47
	Other assets	**2**	5
Total income taxes receivable		**599**	52
Income taxes payable	Accrued expense	**(248)**	(198)
Total income taxes receivable (payable)		**$ 351**	$ (146)

18. Income Taxes (Continued)

Tax carryforwards available for use on future income tax returns at December 31, 2011, were as follows:

millions	**Domestic**	**Foreign**	**Expiration**
Net operating loss—federal	$ 1,728	$ —	2031
Net operating loss—foreign	$ —	$ 825	2016 - indefinite
Net operating loss—state	$ 4,609	$ —	2012-2030
Foreign tax credits	$ 119	$ —	2015-2021
Charitable contribution	$ 27	$ —	2016
Texas margins tax credit	$ 37	$ —	2026

Changes in the balance of unrecognized tax benefits excluding interest and penalties on uncertain tax positions are as follows:

	Assets (Liabilities)		
millions	**2011**	2010	2009
Balance at January 1	**$ (32)**	$ (29)	$ (132)
Increases related to prior-year tax positions	**—**	(13)	(17)
Decreases related to prior-year tax positions	**3**	8	89
Increases related to current-year tax positions	**(10)**	—	(6)
Decreases related to current-year tax positions	**—**	—	8
Settlements	**8**	2	29
Balance at December 31	**$ (31)**	$ (32)	$ (29)

Included in the 2011 ending balance of unrecognized tax benefits presented above are potential benefits of $(22) million that would affect the effective tax rate on income if recognized. Also included in the 2011 ending balance are benefits of $(9) million related to tax positions for which the ultimate deductibility is highly certain, but the timing of such deductibility is uncertain. The Company estimates that $(5) million to $(14) million of unrecognized tax benefits related to adjustments to taxable income and credits previously recorded pursuant to the accounting standard for accounting for tax uncertainties will reverse within the next 12 months due to expiration of statutes of limitation and audit settlements.

At December 31, 2011 and 2010, the Company had approximately $18 million and $26 million, respectively, of accrued interest related to uncertain tax positions. During 2011 and 2010, the Company recognized $(8) million and $12 million, respectively, in income tax expense (benefit) for interest and penalties.

Anadarko is subject to audit by tax authorities in the U.S. federal, state, and local tax jurisdictions as well as in various foreign jurisdictions. The Company is currently under routine examination by the U.S. Internal Revenue Service for the tax years 2010 and 2011.

Income tax audits and the Company's acquisition and divestiture activity have given rise to tax disputes in U.S. and foreign jurisdictions. See *Note 16—Contingencies—Other Litigation.* Management does not believe that the final resolution of outstanding tax audits and litigation will have a material adverse effect on the Company's consolidated financial position, results of operations, or cash flows.

18. Income Taxes (Continued)

The following is a list of tax years subject to examination by major tax jurisdiction.

	Tax Year
United States	2008-2011
China	2006-2010
Algeria	2008-2010
Ghana	2006-2010

19. Supplemental Cash Flow Information

The following presents cash paid for interest (net of amounts capitalized) and income taxes, as well as non-cash investing and financing transactions.

	Years Ended December 31,		
millions	**2011**	2010	2009
Cash paid:			
Interest	**$ 806**	$ 672	$ 724
Income taxes	**$ 262**	$ 308	$ 194
Non-cash investing activities:			
Fair value of properties and equipment received in non-cash exchange transactions	**$ 19**	$ 37	$ 280
Gain related to the fair-value remeasurement of Anadarko's pre-acquisition 7% equity interest in the Wattenberg Plant	**$ 21**	$ —	$ —
Non-cash financing activities:			
Capital lease obligation	**$ (118)**	$ 226	$ —

20. Segment Information

Anadarko's primary business segments are vertically integrated within the oil and gas industry. These segments are separately managed due to distinct operational differences and unique technology, distribution, and marketing requirements. The Company's three reporting segments are oil and gas exploration and production, midstream, and marketing. The oil and gas exploration and production segment explores for and produces natural gas, crude oil, condensate, and NGLs. The midstream segment engages in gathering, processing, treating, and transporting Anadarko and third-party oil, natural-gas, and NGLs production. The marketing segment sells most of Anadarko's production, as well as third-party purchased volumes.

During the first quarter of 2011, the chief operating decision maker (CODM) began separately assessing the performance of, and resource allocation to, the WES operating segment. As a result, the midstream operating segment was separated into two operating segments, WES and other midstream activities. The WES and other midstream activities operating segments are aggregated into a single midstream reporting segment due to similar financial and operating characteristics.

20. Segment Information (Continued)

To assess the performance of Anadarko's operating segments, the CODM analyzes income (loss) before income taxes, interest expense, exploration expense, DD&A, impairments, Deepwater Horizon settlement and related costs, and unrealized (gains) losses on derivatives, net, less net income attributable to noncontrolling interests (Adjusted EBITDAX). The Company's definition of Adjusted EBITDAX excludes interest expense to allow for assessment of segment operating results without regard to Anadarko's financing methods or capital structure. Adjusted EBITDAX also excludes exploration expense, as it is not an indicator of operating efficiency for a given reporting period. However, exploration expense is monitored by management as part of costs incurred in exploration and development activities. Similarly, DD&A and impairments are excluded from Adjusted EBITDAX as a measure of segment operating performance because capital expenditures are evaluated at the time capital costs are incurred. Anadarko's definition of Adjusted EBITDAX excludes Deepwater Horizon settlement and related costs as these costs are outside the normal operations of the Company. See *Note 2—Deepwater Horizon Events*. Finally, unrealized (gains) losses on derivatives, net are excluded from Adjusted EBITDAX because unrealized (gains) losses are not considered a measure of asset operating performance. Management believes that the presentation of Adjusted EBITDAX provides information useful in assessing the Company's financial condition and results of operations and that Adjusted EBITDAX is a widely accepted financial indicator of a company's ability to incur and service debt, fund capital expenditures, and make distributions to stockholders.

Adjusted EBITDAX may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with net income (loss) attributable to common stockholders and other performance measures, such as operating income or cash flows from operating activities. Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) before income taxes.

	Years Ended December 31,		
millions	**2011**	2010	2009
Income (loss) before income taxes	**$ (3,424)**	$ 1,641	$ (108)
Exploration expense	**1,076**	974	1,107
DD&A	**3,830**	3,714	3,532
Impairments	**1,774**	216	115
Deepwater Horizon settlement and related costs[(1)]	**3,930**	15	—
Interest expense	**839**	855	702
Unrealized (gains) losses on derivatives, net[(2)]	**616**	(114)	717
Less: Net income attributable to noncontrolling interests	**81**	60	32
Consolidated Adjusted EBITDAX	**$ 8,560**	$ 7,241	$ 6,033

(1) In the third quarter of 2011, the Company revised the definition of Adjusted EBITDAX to exclude the Deepwater Horizon settlement and related costs. The prior periods have been adjusted to reflect this change.

(2) In the fourth quarter of 2010, the Company revised the definition of Adjusted EBITDAX to exclude the impact of unrealized (gains) losses on derivatives, net. The prior periods have been adjusted to reflect this change.

The Company's accounting policies for individual segments are the same as those described in the summary of significant accounting policies, with the following exception: certain intersegment commodity contracts may meet the U.S. Generally Accepted Accounting Principles (GAAP) definition of a derivative instrument, which would be accounted for at fair value under GAAP. However, Anadarko does not recognize any mark-to-market adjustments on such intersegment arrangements. Additionally, intersegment asset transfers are accounted for at historical cost basis, and do not give rise to gain or loss recognition.

20. Segment Information (Continued)

The following presents selected financial information for Anadarko's reporting segments for the respective years ended December 31. Information presented below as "Other and Intersegment Eliminations" includes results from hard-minerals non-operated joint ventures and royalty arrangements; and corporate, financing, and certain hedging activities.

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
2011					
Sales revenues	$ 7,519	$ 342	$ 6,023	$ (2)	$ 13,882
Intersegment revenues	5,005	957	(5,515)	(447)	—
Gains (losses) on divestitures and other, net	(41)	(13)	—	139	85
Total revenues and other	12,483	1,286	508	(310)	13,967
Operating costs and expenses[1]	3,696	786	559	186	5,227
Realized (gains) losses on derivatives, net	—	—	—	(167)	(167)
Other (income) expense, net	—	—	—	254	254
Net income attributable to noncontrolling interests	—	81	—	—	81
Total expenses and other	3,696	867	559	273	5,395
Unrealized (gains) losses on derivatives, net included in marketing revenue	—	—	(12)	—	(12)
Adjusted EBITDAX	$ 8,787	$ 419	$ (63)	$ (583)	$ 8,560
Net properties and equipment	$ 32,235	$ 3,432	$ 9	$ 1,825	$ 37,501
Capital expenditures	$ 5,026	$ 1,420	$ —	$ 107	$ 6,553
Goodwill	$ 5,475	$ 166	$ —	$ —	$ 5,641

20. Segment Information (Continued)

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
2010					
Sales revenues	$ 5,613	$ 192	$ 5,037	$ —	$ 10,842
Intersegment revenues	4,136	831	(4,572)	(395)	—
Gains (losses) on divestitures and other, net	—	—	—	142	142
Total revenues and other	9,749	1,023	465	(253)	10,984
Operating costs and expenses[1]	2,963	655	457	221	4,296
Realized (gains) losses on derivatives, net	—	—	—	(498)	(498)
Other (income) expense, net	—	—	—	(119)	(119)
Net income attributable to noncontrolling interests	—	60	—	—	60
Total expenses and other	2,963	715	457	(396)	3,739
Unrealized (gains) losses on derivatives, net included in marketing revenue	—	—	(4)	—	(4)
Adjusted EBITDAX	$ 6,786	$ 308	$ 4	$ 143	$ 7,241
Net properties and equipment	$ 32,850	$ 3,303	$ 9	$ 1,795	$ 37,957
Capital expenditures	$ 4,672	$ 384	$ —	$ 113	$ 5,169
Goodwill	$ 5,143	$ 139	$ —	$ —	$ 5,282
2009					
Sales revenues	$ 3,844	$ 222	$ 4,144	$ —	$ 8,210
Intersegment revenues	3,479	718	(3,842)	(355)	—
Gains (losses) on divestitures and other, net	43	1	—	89	133
Reversal of accrual for DWRRA dispute	657	—	—	—	657
Total revenues and other	8,023	941	302	(266)	9,000
Operating costs and expenses[1]	2,499	646	451	273	3,869
Realized (gains) losses on derivatives, net	—	—	—	(852)	(852)
Other (income) expense, net	—	—	—	(43)	(43)
Net income attributable to noncontrolling interests	—	32	—	—	32
Total expenses and other	2,499	678	451	(622)	3,006
Unrealized (gains) losses on derivatives, net included in marketing revenue	—	—	39	—	39
Adjusted EBITDAX	$ 5,524	$ 263	$ (110)	$ 356	$ 6,033
Net properties and equipment	$ 32,338	$ 3,091	$ 9	$ 1,766	$ 37,204
Capital expenditures	$ 4,001	$ 303	$ —	$ 254	$ 4,558
Goodwill	$ 5,143	$ 139	$ —	$ —	$ 5,282

[1] Operating costs and expenses exclude exploration expense, DD&A, impairments, and Deepwater Horizon settlement and related costs since these expenses are excluded from Adjusted EBITDAX. For the year ended December 31, 2010 and 2009, $79 million and $61 million, respectively, has been reclassified from the oil and gas exploration and production segment to the midstream segment to properly reflect the previously reported amounts.

20. Segment Information (Continued)

The following represents Anadarko's sales revenues (based on the origin of the sales) and net properties and equipment by geographic area.

	Years Ended December 31,		
millions	**2011**	2010	2009
Sales Revenues			
United States	**$ 10,477**	$ 8,806	$ 6,773
Algeria	**2,258**	1,582	1,133
Other International	**1,147**	454	304
Total	**$ 13,882**	$ 10,842	$ 8,210

	December 31,	
millions	**2011**	2010
Net Properties and Equipment		
United States	**$ 33,050**	$ 34,100
Algeria	**1,416**	1,165
Other International	**3,035**	2,692
Total	**$ 37,501**	$ 37,957

21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans

The Company has non-contributory U.S. defined-benefit pension plans, including both qualified and supplemental plans, and a foreign contributory defined-benefit pension plan. The Company also provides certain health care and life insurance benefits for certain retired employees. Retiree health care benefits are funded by contributions from the retiree, and in certain circumstances, contributions from the Company. The Company's retiree life insurance plan is noncontributory.

In 2011, the Company made contributions of $301 million to its funded pension plans, $10 million to its unfunded pension plans, and $17 million to its unfunded other postretirement benefit plans. While reported benefit obligations exceed the fair value of pension and other postretirement plan assets at December 31, 2011, the Company monitors the funded status of its funded pension and other postretirement benefit plans to ensure that plan funds are sufficient to continue paying benefits. Contributions to funded plans increase plan assets, while contributions to unfunded plans are used to fund current benefit payments. The Company expects to contribute approximately $80 million to its funded pension plans, approximately $35 million to its unfunded pension plans, and approximately $20 million to its unfunded other postretirement benefit plans in 2012.

21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

The following sets forth changes in the benefit obligations and fair value of plan assets for the Company's pension and other postretirement benefit plans for the years ended December 31, 2011 and 2010, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2011 and 2010.

	Pension Benefits		Other Benefits	
millions	**2011**	2010	**2011**	2010
Change in benefit obligations				
Benefit obligations at beginning of year	**$ 1,882**	$ 1,630	**$ 316**	$ 316
Service cost	**78**	69	**9**	9
Interest cost	**85**	84	**16**	16
Plan amendments	**(12)**	6	**—**	—
Actuarial (gain) loss	**94**	217	**30**	(8)
Participant contributions	**1**	1	**4**	4
Benefit payments	**(103)**	(122)	**(21)**	(21)
Foreign-currency exchange-rate changes	**(1)**	(3)	**—**	—
Benefit obligations at end of year	**$ 2,024**	$ 1,882	**$ 354**	$ 316
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 1,104**	$ 979	**$ —**	$ —
Actual return on plan assets	**(4)**	147	**—**	—
Employer contributions	**311**	102	**17**	17
Participant contributions	**1**	1	**4**	4
Benefit payments	**(103)**	(122)	**(21)**	(21)
Foreign-currency exchange-rate changes	**(1)**	(3)	**—**	—
Fair value of plan assets at end of year	**$ 1,308**	$ 1,104	**$ —**	$ —
Funded status of the plans at end of year	**$ (716)**	$ (778)	**$ (354)**	$ (316)
Total recognized amounts in the balance sheet consist of:				
Other assets	**$ 11**	$ 14	**$ —**	$ —
Accrued expenses	**(33)**	(29)	**(18)**	(17)
Other long-term liabilities—other	**(694)**	(763)	**(336)**	(299)
Total	**$ (716)**	$ (778)	**$ (354)**	$ (316)
Total recognized amounts in accumulated other comprehensive income consist of:				
Prior service cost (credit)	**$ (2)**	$ 12	**$ 5**	$ 5
Net actuarial (gain) loss	**853**	755	**(4)**	(34)
Total	**$ 851**	$ 767	**$ 1**	$ (29)

The accumulated benefit obligation for all defined-benefit pension plans was $1.9 billion and $1.7 billion at December 31, 2011 and 2010, respectively. For the Company's defined-benefit pension plans with accumulated benefit obligations in excess of plan assets, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets were $1.9 billion, $1.8 billion, and $1.2 billion, respectively, at December 31, 2011, and $1.8 billion, $1.6 billion, and $1.0 billion, respectively, at December 31, 2010.

21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

The following sets forth the Company's pension and other postretirement benefit cost and amounts recognized in other comprehensive income (before tax benefit) for the respective years ended December 31.

	Pension Benefits			Other Benefits		
millions	**2011**	2010	2009	**2011**	2010	2009
Components of net periodic benefit cost						
Service cost	**$ 78**	$ 69	$ 54	**$ 9**	$ 9	$ 9
Interest cost	**85**	84	79	**16**	16	17
Expected return on plan assets	**(85)**	(80)	(71)	**—**	—	—
Amortization of net actuarial loss (gain)	**85**	65	49	**—**	(3)	(2)
Amortization of net prior service cost (credit)	**2**	3	1	**—**	(1)	(1)
Settlement loss (gain)	**—**	—	11	**—**	—	—
Net periodic benefit cost	**$ 165**	$ 141	$ 123	**$ 25**	$ 21	$ 23
Amounts recognized in other comprehensive income (expense)						
Net actuarial gain (loss)	**$ (183)**	$ (151)	$ (221)	**$ (30)**	$ 8	$ 16
Amortization of net actuarial (gain) loss	**85**	65	49	**—**	(3)	(2)
Amortization of settlement (gain) loss	**—**	—	11	**—**	—	—
Net prior service (cost) credit	**12**	(6)	—	**—**	—	—
Amortization of net prior service cost (credit)	**2**	3	1	**—**	(1)	(1)
Total amounts recognized in other comprehensive income (expense)	**$ (84)**	$ (89)	$ (160)	**$ (30)**	$ 4	$ 13

The estimated amounts of net actuarial loss and net prior service cost for the pension and other postretirement plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2012 are $93 million and $1 million, respectively.

Following are the weighted-average assumptions used by the Company in determining the pension and other postretirement benefit obligations at December 31, 2011 and 2010.

	Pension Benefits		Other Benefits	
	2011	2010	**2011**	2010
Discount rate	**4.50%**	4.75%	**4.75%**	5.25%
Rates of increase in compensation levels	**4.50%**	5.00%	**4.50%**	5.00%

Accumulated and projected benefit obligations are measured as the present value of future cash payments. The Company discounts those cash payments using a discount rate that reflects the weighted average of market-observed yields for select high quality (AA-rated) fixed-income securities with cash flows that correspond to the expected amounts and timing of benefit payments. Discount-rate selection for measurements prior to December 31, 2011, was based on a similar cash-flow-matching analysis, although, instead of using a portfolio of select high quality fixed-income securities to determine the effective settlement rate for a given plan obligation, the Company relied primarily on a published yield curve derived from market-observed yields for a universe of high quality bonds. Both methods are acceptable and result in a discount-rate assumption that represents an estimate of the interest rate at which the pension and other postretirement benefit obligations could effectively be settled on the measurement date. However, the Company believes a discount rate reflecting yields for high-quality fixed-income securities better corresponds to the Company's expectations as

21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

to the amount and timing of its benefit payments. Assumed rates of compensation increases for active participants vary by age group, with resulting weighted-average assumed rate (weighted by the plan-level benefit obligation) provided in the preceding table.

Following are the weighted-average assumptions used by the Company in determining the net periodic pension and other postretirement benefit cost for 2011, 2010, and 2009.

	Pension Benefits			Other Benefits		
	2011	2010	2009	**2011**	2010	2009
Discount rate	**4.75%**	5.25%	6.00%	**5.25%**	5.50%	6.00%
Long-term rate of return on plan assets	**7.00%**	7.50%	7.50%	**N/A**	N/A	N/A
Rates of increase in compensation levels	**5.00%**	5.00%	5.00%	**5.00%**	5.00%	5.00%

At December 31, 2010, a 10% annual rate of increase in the per-capita cost of covered health care benefits for 2011 is assumed for purposes of measuring other postretirement benefit obligations. At December 31, 2011, a 9% increase for 2012 was assumed for purposes of measuring other postretirement benefit obligations. This rate is expected to gradually decrease to 5% in 2018 and beyond. The assumed health care cost trend rate can have a significant effect on the cost and obligation amounts reported for the health care plan. A 1% change in the assumed health care cost trend rate over the projected period would have the following effects:

millions	1% Increase	1% Decrease
Effect on total of service and interest cost components	$ 2	$ (2)
Effect on other postretirement benefit obligation	$ 26	$ (22)

Plan Assets

Investment Policies and Strategies The Company has adopted a balanced, diversified investment strategy, with the intent of maximizing returns without exposure to undue risk. Investments are typically made through investment managers across several investment categories (domestic large- and small-capitalization equity securities, international equity securities, fixed-income securities, real estate, hedge funds, and private equity), with selective exposure to Growth/Value investment styles. Performance for each investment is measured relative to the appropriate index benchmark for its category. Target asset-allocation percentages by major category are 45%-55% equity securities, 20%-30% fixed income, and up to 25% in a combination of other investments such as real estate, hedge funds, and private equity. Investment managers have full discretion as to investment decisions regarding all funds under their management to the extent permitted within investment guidelines.

Although investment managers may, at their discretion and within investment guidelines, invest in Anadarko securities, there are no direct investments in Anadarko securities included in plan assets. There may be, however, indirect investments in Anadarko securities through the plans' collective fund investments. The expected long-term rate of return on plan assets assumption was determined using the year-end 2011 pension investment balances by asset class and expected long-term asset allocation. The expected return for each asset class reflects capital-market projections formulated using a forward-looking building-block approach, while also taking into account historical return trends and current market conditions. Equity returns generally reflect long-term expectations of real earnings growth, dividend yield, and inflation. Returns on fixed-income securities are generally developed based on expected inflation, real bond yield, and risk spread (as appropriate), adjusted for the expected effect that changing yields have on the rate of return. Other asset-class returns are derived from their relationship to the equity and fixed-income markets.

21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

The fair value of the Company's pension plan assets by asset category and input level within the fair-value hierarchy are as follows:

December 31, 2011 *millions*	**Level 1**	**Level 2**	**Level 3**	**Total**
Investments:				
Cash and cash equivalents	$ 37	$ 54	$ —	$ 91
Fixed income:				
Mortgage-backed securities	—	66	—	66
U.S. Government securities	1	49	—	50
Other fixed-income securities[1]	36	171	—	207
Equity securities:				
Domestic	265	94	—	359
International	91	203	—	294
Other:				
Real estate	—	37	72	109
Private equity	—	—	55	55
Hedge funds and other alternative strategies	26	—	64	90
Total investments[2]	$ 456	$ 674	$ 191	$ 1,321
Liabilities:				
Hedge funds and other alternative strategies	$ (12)	$ —	$ —	$ (12)
Total liabilities[2]	$ (12)	$ —	$ —	$ (12)

(1) Amounts include investments in diversified fixed-income collective investment funds with exposure to mortgage-backed securities, government-issued securities, corporate debt, and other fixed-income securities.

(2) Amount excludes net payables of $(1) million primarily related to Level 1 investments.

21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

December 31, 2010 *millions*	**Level 1**	**Level 2**	**Level 3**	**Total**
Investments:				
Cash and cash equivalents	$ 18	$ 30	$ —	$ 48
Fixed income:(1)				
Mortgage-backed securities	—	79	—	79
U.S. Government securities	17	28	—	45
Other fixed-income securities(2)	71	105	—	176
Equity securities:(1)				
Domestic	258	56	—	314
International	92	211	—	303
Other:				
Real estate	31	—	9	40
Private equity	—	—	41	41
Hedge funds and other alternative strategies	27	—	49	76
Total investments(3)	$ 514	$ 509	$ 99	$ 1,122
Liabilities:				
Hedge funds and other alternative strategies	$ (19)	$ —	$ —	$ (19)
Total liabilities(3)	$ (19)	$ —	$ —	$ (19)

(1) Certain amounts have been reclassified to conform to current-year presentation.
(2) Amounts include investments in diversified fixed-income collective investment funds with exposure to mortgage-backed securities, government-issued securities, corporate debt, and other fixed-income securities.
(3) Amount excludes net receivables of $1 million primarily related to Level 1 investments.

21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Investments in securities traded in active markets are measured based on quoted prices, which represent Level 1 inputs above. Investments based on Level 2 inputs include direct investments in corporate debt and other fixed-income securities, as well as shares of open-end mutual funds or similar investment vehicles that do not have a readily determinable fair value, but are valued at the net asset value per share (NAV). For such funds, the NAV is the value at which investors transact with the fund, and is determined by the fund based on the estimated fair values of the underlying fund assets. Fair value of investments included as Level 3 inputs generally also reflect investments valued at fund NAVs, but, unlike investments characteristic of Level 2 fair-value measurements, such plan assets have significant liquidity restrictions or other features that are not reflected in NAV.

The following sets forth a summary of changes in the fair value of investments based on Level 3 inputs.

millions	Hedge Funds and Other Alternative Strategies	Private Equity	Real Estate	Total
Balance at January 1, 2011	**$ 49**	**$ 41**	**$ 9**	**$ 99**
Acquisitions (dispositions), net	**17**	**6**	**60**	**83**
Actual return on plan assets:				
Relating to assets sold during the reporting period	**(1)**	**1**	**—**	**—**
Relating to assets still held at the reporting date	**(1)**	**7**	**3**	**9**
Balance at December 31, 2011	**$ 64**	**$ 55**	**$ 72**	**$ 191**
Balance at January 1, 2010	$ 13	$ 25	$ —	$ 38
Acquisitions (dispositions), net	35	10	9	54
Actual return on plan assets:				
Relating to assets sold during the reporting period	—	2	—	2
Relating to assets still held at the reporting date	1	4	—	5
Balance at December 31, 2010	$ 49	$ 41	$ 9	$ 99

Risks and Uncertainties The plan assets include various investment securities that are exposed to various risks, such as interest-rate, credit, and market risks. Due to the level of risk associated with certain investment securities, it is reasonably possible that changes in the values of investment securities could significantly impact the plan assets.

The plan assets may include securities with contractual cash flows, such as asset-backed securities, collateralized mortgage obligations, and commercial mortgage-backed securities, including securities backed by subprime mortgage loans. The value, liquidity, and related income of those securities are sensitive to changes in economic conditions, including real estate value, delinquencies, or defaults, or both, and may be adversely affected by shifts in the market's perception of the issuers and changes in interest rates.

21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Expected Benefit Payments

The following provides an estimate of benefit payments for the next ten years. These estimates reflect benefit increases due to continuing employee service.

millions	Pension Benefit Payments	Other Benefit Payments
2012	$ 214	$ 19
2013	209	19
2014	204	21
2015	197	22
2016	190	23
2017-2021	784	121

Defined-Contribution Plans The Company maintains several defined-contribution benefit plans, including the Anadarko Employee Savings Plan (ESP). All U.S. payroll-based regular employees of the Company on its U.S. payroll are eligible to participate in the ESP by making elective contributions that are matched by the Company, subject to certain limitations. The Company recognized expense of $41 million, $40 million, and $43 million for 2011, 2010, and 2009, respectively, related to these plans.

ANADARKO PETROLEUM CORPORATION
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In December 2009, Anadarko adopted revised oil and gas reserve estimation and disclosure requirements that conformed the definition of proved reserves to the Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting rules, issued by the SEC in 2008. An accounting standards update revised the definition of proved oil and gas reserves to require that the average, first-day-of-the-month price during the 12-month period before the end of the year rather than the year-end price, must be used when estimating whether reserve quantities are economic to produce. This same 12-month average price is also used in calculating the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future net cash flows. The rules also allow for the use of reliable technologies to estimate proved oil, natural-gas, and natural-gas liquids (NGLs) reserves if those technologies have been demonstrated to result in reliable conclusions about reserve volumes.

The unaudited supplemental information on oil and gas exploration and production activities for 2011, 2010, and 2009 has been presented in accordance with the revised reserve estimation and disclosure rules, which were not applied retrospectively. The December 31, 2008 data is presented in accordance with Financial Accounting Standards Board (FASB) oil and gas disclosure requirements effective at that time. However, historical information has been reclassified to conform to the geographic areas required to be disclosed under the revised accounting standard. Disclosures by geographic area include the United States and International. The International geographic area consists of proved reserves located in Algeria, China, and Ghana.

Oil and Gas Reserves

The following reserves disclosures reflect estimates of proved reserves, proved developed reserves, and proved undeveloped reserves, net of third-party royalty interests, of natural gas, oil, condensate, and NGLs owned at each year end and changes in proved reserves during each of the last three years. Natural-gas volumes are presented in billions of cubic feet (Bcf) at a pressure base of 14.73 pounds per square inch and volumes for oil, condensate, and NGLs are presented in millions of barrels (MMBbls). Total volumes are presented in millions of barrels of oil equivalent (MMBOE). For this computation, one barrel is assumed to be the equivalent of 6,000 cubic feet of natural gas. Shrinkage associated with NGLs has been deducted from the natural-gas reserve volumes.

Oil and Gas Reserves (Continued)

Reserves for international locations are calculated in accordance with the terms of governing agreements. The international reserves include estimated quantities allocated to Anadarko for recovery of costs and income taxes and Anadarko's net equity share after recovery of such costs.

The Company's estimates of proved reserves are made using available geological and reservoir data as well as production performance data. These estimates are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. The results of infill drilling are treated as positive revisions due to increases to expected recovery. Other revisions are due to changes in, among other things, reservoir performance, prices, economic conditions, and governmental restrictions.

In 2011, Anadarko added 174 MMBOE of proved reserves primarily as the result of successful drilling in the United States. Reserves revisions for 2011 include an increase of 210 MMBOE primarily related to successful infill drilling in the large onshore areas, such as the Greater Natural Buttes, Wattenberg, and Pinedale fields, and an increase of 8 MMBOE driven by higher oil prices. Sales of proved reserves in place were 29 MMBOE, related to onshore domestic assets.

In 2010, Anadarko added 83 MMBOE of proved reserves primarily as the result of successful drilling in the United States. Reserves revisions for 2010 include an increase of 246 MMBOE primarily related to successful infill drilling in the large onshore natural-gas plays, such as the Greater Natural Buttes, Wattenberg, and Pinedale fields, and an increase of 29 MMBOE driven by higher oil and gas prices. Sales of proved reserves in place were 6 MMBOE, related to onshore domestic and international assets.

In 2009, Anadarko added 70 MMBOE of proved reserves primarily as the result of successful drilling in the United States and international locations. Reserves revisions for 2009 included an increase of 212 MMBOE primarily related to large onshore natural-gas plays, such as the Greater Natural Buttes and Pinedale fields, as a result of successful infill drilling. The revisions include a decrease of 39 MMBOE driven by lower natural-gas prices. Sales and acquisitions of proved reserves in place were 24 MMBOE and 32 MMBOE, respectively, related to onshore domestic assets.

Prices used to compute the information presented in the tables below are adjusted only for fixed and determinable amounts under provisions in existing contracts. These prices, before adjustments, were $4.12, $4.38, and $3.87 per MMBtu of natural gas and $96.19, $79.43, and $61.18 per barrel of oil, respectively, for 2011, 2010, and 2009.

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Oil and Gas Reserves (Continued)

	Natural Gas (Bcf)			Oil and Condensate (MMBbls)		
	United States	**International**	**Total**	**United States**	**International**	**Total**
Proved Reserves						
December 31, 2008	8,105	—	8,105	487	222	709
Revisions of prior estimates	228	—	228	45	16	61
Extensions, discoveries, and other additions	210	—	210	13	20	33
Purchases in place	149	—	149	1	—	1
Sales in place	(111)	—	(111)	(2)	—	(2)
Production	(817)	—	(817)	(44)	(25)	(69)
December 31, 2009	7,764	—	7,764	500	233	733
Revisions of prior estimates	851	—	851	32	44	76
Extensions, discoveries, and other additions	363	—	363	13	—	13
Purchases in place	7	—	7	—	—	—
Sales in place	(39)	—	(39)	—	—	—
Production	(829)	—	(829)	(47)	(26)	(73)
December 31, 2010	**8,117**	**—**	**8,117**	**498**	**251**	**749**
Revisions of prior estimates	**550**	**—**	**550**	**44**	**14**	**58**
Extensions, discoveries, and other additions	**614**	**—**	**614**	**52**	**—**	**52**
Purchases in place	**—**	**—**	**—**	**—**	**—**	**—**
Sales in place	**(64)**	**—**	**(64)**	**(10)**	**—**	**(10)**
Production	**(852)**	**—**	**(852)**	**(48)**	**(30)**	**(78)**
December 31, 2011	**8,365**	**—**	**8,365**	**536**	**235**	**771**
Proved Developed Reserves						
December 31, 2008	6,117	—	6,117	285	145	430
December 31, 2009	5,884	—	5,884	300	144	444
December 31, 2010	5,982	—	5,982	303	150	453
December 31, 2011	**6,113**	**—**	**6,113**	**352**	**173**	**525**
Proved Undeveloped Reserves						
December 31, 2008	1,988	—	1,988	202	77	279
December 31, 2009	1,880	—	1,880	200	89	289
December 31, 2010	2,135	—	2,135	195	101	296
December 31, 2011	**2,252**	**—**	**2,252**	**184**	**62**	**246**

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Oil and Gas Reserves (Continued)

	NGLs (MMBbls)			Total (MMBOE)		
	United States	**International**	**Total**	**United States**	**International**	**Total**
Proved Reserves						
December 31, 2008	205	12	217	2,043	234	2,277
Revisions of prior estimates(1)	69	5	74	152	21	173
Extensions, discoveries, and other additions	2	—	2	50	20	70
Purchases in place	6	—	6	32	—	32
Sales in place	(3)	—	(3)	(24)	—	(24)
Production	(19)	—	(19)	(199)	(25)	(224)
December 31, 2009	260	17	277	2,054	250	2,304
Revisions of prior estimates(1)	60	(4)	56	235	40	275
Extensions, discoveries, and other additions	10	—	10	83	—	83
Purchases in place	—	—	—	1	—	1
Sales in place	—	—	—	(6)	—	(6)
Production	(23)	—	(23)	(209)	(26)	(235)
December 31, 2010	**307**	**13**	**320**	**2,158**	**264**	**2,422**
Revisions of prior estimates(1)	**68**	**—**	**68**	**204**	**14**	**218**
Extensions, discoveries, and other additions	**20**	**—**	**20**	**174**	**—**	**174**
Purchases in place	**—**	**—**	**—**	**—**	**—**	**—**
Sales in place	**(8)**	**—**	**(8)**	**(29)**	**—**	**(29)**
Production	**(26)**	**—**	**(26)**	**(216)**	**(30)**	**(246)**
December 31, 2011	**361**	**13**	**374**	**2,291**	**248**	**2,539**
Proved Developed Reserves						
December 31, 2008	150	—	150	1,455	145	1,600
December 31, 2009	199	—	199	1,480	144	1,624
December 31, 2010	222	—	222	1,523	150	1,673
December 31, 2011	**267**	**—**	**267**	**1,638**	**173**	**1,811**
Proved Undeveloped Reserves						
December 31, 2008	55	12	67	588	89	677
December 31, 2009	61	17	78	574	106	680
December 31, 2010	85	13	98	635	114	749
December 31, 2011	**94**	**13**	**107**	**653**	**75**	**728**

(1) Revisions of prior estimates for 2011, 2010, and 2009 total proved reserves include 203 MMBOE, 312 MMBOE, and 125 MMBOE, respectively, of additions generated by Anadarko's infill drilling programs.

ANADARKO PETROLEUM CORPORATION
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Capitalized Costs

Capitalized costs include the cost of properties, equipment, and facilities for oil and natural-gas producing activities. Capitalized costs for proved properties include costs for oil and natural-gas leaseholds where proved reserves have been identified, development wells, and related equipment and facilities, including development wells in progress. Capitalized costs for unproved properties include costs for acquiring oil and gas leaseholds where no proved reserves have been identified, including costs of exploratory wells that are in the process of drilling or in active completion, and costs of exploratory wells suspended or waiting on completion. Capitalized costs associated with activities of the Company's midstream and marketing segments, and other corporate activities are not included.

millions	**United States**	**International**	**Total**
December 31, 2011			
Capitalized			
Unproved properties	**$ 7,020**	**$ 1,328**	**$ 8,348**
Proved properties	**39,711**	**4,652**	**44,363**
	46,731	**5,980**	**52,711**
Less: Accumulated DD&A	**18,908**	**1,568**	**20,476**
Net capitalized costs	**$ 27,823**	**$ 4,412**	**$ 32,235**
December 31, 2010			
Capitalized			
Unproved properties	$ 7,518	$ 2,331	$ 9,849
Proved properties	35,792	2,687	38,479
	43,310	5,018	48,328
Less: Accumulated DD&A	14,302	1,176	15,478
Net capitalized costs	$ 29,008	$ 3,842	$ 32,850

ANADARKO PETROLEUM CORPORATION
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Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development

Amounts reported as costs incurred include both capitalized costs and costs charged to expense when incurred for oil and gas property acquisition, exploration, and development activities. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligations resulting from changes to cost estimates during the year. Exploration costs presented below include the costs of drilling and equipping successful and unsuccessful exploration wells during the year, geological and geophysical expenses, and the costs of retaining undeveloped leaseholds. Development costs include the costs of drilling and equipping development wells, and construction of related production facilities. Costs associated with activities of the Company's midstream and marketing segments, and other corporate activities are not included.

millions	United States	International	Total
Year Ended December 31, 2011			
Property acquisitions			
Unproved	**$ 610**	**$ 37**	**$ 647**
Proved	**—**	**—**	**—**
Exploration	**666**	**803**	**1,469**
Development	**2,970**	**555**	**3,525**
Total Costs Incurred	**$ 4,246**	**$ 1,395**	**$ 5,641**
Year Ended December 31, 2010			
Property acquisitions			
Unproved	$ 428	$ 91	$ 519
Proved	22	—	22
Exploration	693	585	1,278
Development	2,368	899	3,267
Total Costs Incurred	$ 3,511	$ 1,575	$ 5,086
Year Ended December 31, 2009			
Property acquisitions			
Unproved	$ 270	$ 9	$ 279
Proved	266	—	266
Exploration	743	486	1,229
Development	2,005	881	2,886
Total Costs Incurred	$ 3,284	$ 1,376	$ 4,660

ANADARKO PETROLEUM CORPORATION
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Results of Operations

Results of operations for producing activities consist of all activities within the oil and gas exploration and production segment. Net revenues from production include only the revenues from the production and sale of natural gas, oil, condensate, and NGLs. Gains (losses) on property dispositions represent net gains or losses on sales of oil and gas properties. Deepwater Horizon settlement and related costs represents the Company's $4.0 billion settlement with BP, and associated legal and other costs, net of related insurance recoveries. Reversal of accrual for Deepwater Royalty Relief Act (DWRRA) dispute represents the reversal of previously recorded liabilities for royalties due on leases subject to litigation with the Department of Interior as described in *Note 16—Contingencies* in the *Notes to Consolidated Financial Statements*. Production costs are those incurred to operate and maintain wells and related equipment and facilities used in oil and gas operations. Exploration expenses include dry hole costs, leasehold impairments, geological and geophysical expenses, and the costs of retaining unproved leaseholds. Income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion, and amortization allowances, after giving effect to permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas activities.

millions	United States	International	Total
Year Ended December 31, 2011			
Net revenues from production			
Third-party sales	$ 5,778	$ 2,051	$ 7,829
Sales to consolidated affiliates	3,652	1,353	5,005
Gains (losses) on property dispositions	(495)	454	(41)
	8,935	3,858	12,793
Production costs			
Oil and gas operating	862	131	993
Oil and gas transportation and other	867	23	890
Production-related general and administrative expenses	322	20	342
Other taxes	646	811	1,457
	2,697	985	3,682
Exploration expenses	688	388	1,076
Depreciation, depletion, and amortization	3,193	391	3,584
Impairments related to oil and gas properties	1,225	—	1,225
Deepwater Horizon settlement and related costs	3,930	—	3,930
	(2,798)	2,094	(704)
Income tax expense	(1,015)	1,027	12
Results of operations	$ (1,783)	$ 1,067	$ (716)

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Results of Operations (Continued)

millions	United States	International	Total
Year Ended December 31, 2010			
Net revenues from production			
Third-party sales	$ 4,369	$ 1,504	$ 5,873
Sales to consolidated affiliates	3,604	532	4,136
Gains (losses) on property dispositions	33	(7)	26
	8,006	2,029	10,035
Production costs			
Oil and gas operating	744	86	830
Oil and gas transportation and other	792	22	814
Production-related general and administrative expenses	274	16	290
Other taxes	456	581	1,037
	2,266	705	2,971
Exploration expenses	677	297	974
Depreciation, depletion, and amortization	3,281	204	3,485
Impairments related to oil and gas properties	145	—	145
Deepwater Horizon settlement and related costs	15	—	15
	1,622	823	2,445
Income tax expense	565	563	1,128
Results of operations	$ 1,057	$ 260	$ 1,317
Year Ended December 31, 2009			
Net revenues from production			
Third-party sales	$ 2,957	$ 1,046	$ 4,003
Sales to consolidated affiliates	3,088	391	3,479
Gains (losses) on property dispositions	2	41	43
Reversal of accrual for DWRRA dispute	657	—	657
	6,704	1,478	8,182
Production costs			
Oil and gas operating	771	88	859
Oil and gas transportation and other	641	22	663
Production-related general and administrative expenses	294	12	306
Other taxes	304	408	712
	2,010	530	2,540
Exploration expenses	810	297	1,107
Depreciation, depletion and amortization	3,138	181	3,319
Impairments related to oil and gas properties	22	—	22
	724	470	1,194
Income tax expense	279	379	658
Results of operations	$ 445	$ 91	$ 536

Standardized Measure of Discounted Future Net Cash Flows

Estimates of future net cash flows from proved reserves of natural gas, oil, condensate, and NGLs for 2011, 2010, and 2009 are computed using the average first-day-of-the-month price during the 12-month period for the respective year. Prices used to compute the information presented in the tables below are adjusted only for fixed and determinable amounts under provisions in existing contracts. These prices, before adjustments, were $4.12, $4.38, and $3.87 per MMBtu of natural gas and $96.19, $79.43, and $61.18 per barrel of oil, respectively, for 2011, 2010, and 2009. Estimated future net cash flows for all periods presented are reduced by estimated future development, production, and abandonment and dismantlement costs based on existing costs, assuming continuation of existing economic conditions, and by estimated future income tax expense. These estimates also include assumptions about the timing of future production of proved reserves, and timing of future development, production costs, and abandonment and dismantlement. Income tax expense, both U.S. and foreign, is calculated by applying the existing statutory tax rates, including any known future changes, to the pretax net cash flows, giving effect to any permanent differences and reduced by the applicable tax basis. The effect of tax credits is considered in determining the income tax expense. The 10-percent discount factor is prescribed by U.S. Generally Accepted Accounting Principles.

The present value of future net cash flows does not purport to be an estimate of the fair value of Anadarko's proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves, and a discount factor more representative of the time value of money and the risks inherent in producing oil and natural gas. Significant changes in estimated reserve volumes or commodity prices could have a material effect on the Company's Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

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

millions	United States	International	Total
December 31, 2011			
Future cash inflows	**$ 98,615**	**$ 27,351**	**$ 125,966**
Future production costs	**30,385**	**8,342**	**38,727**
Future development costs	**10,534**	**995**	**11,529**
Future income tax expenses	**20,391**	**8,101**	**28,492**
Future net cash flows	**37,305**	**9,913**	**47,218**
10% annual discount for estimated timing of cash flows	**17,132**	**3,630**	**20,762**
Standardized measure of discounted future net cash flows	**$ 20,173**	**$ 6,283**	**$ 26,456**
December 31, 2010			
Future cash inflows	$ 82,793	$ 20,633	$ 103,426
Future production costs	26,245	6,989	33,234
Future development costs	8,041	1,040	9,081
Future income tax expenses	16,512	5,543	22,055
Future net cash flows	31,995	7,061	39,056
10% annual discount for estimated timing of cash flows	15,008	2,550	17,558
Standardized measure of discounted future net cash flows	$ 16,987	$ 4,511	$ 21,498
December 31, 2009			
Future cash inflows	$ 60,555	$ 14,699	$ 75,254
Future production costs	21,312	5,665	26,977
Future development costs	7,243	1,644	8,887
Future income tax expenses	10,537	3,641	14,178
Future net cash flows	21,463	3,749	25,212
10% annual discount for estimated timing of cash flows	9,938	1,721	11,659
Standardized measure of discounted future net cash flows	$ 11,525	$ 2,028	$ 13,553

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

millions	United States	International	Total
2011			
Balance at January 1	**$ 16,987**	**$ 4,511**	**$ 21,498**
Sales and transfers of oil and gas produced, net of production costs	**(6,733)**	**(2,420)**	**(9,153)**
Net changes in prices and production costs	**2,424**	**4,777**	**7,201**
Changes in estimated future development costs	**32**	**(709)**	**(677)**
Extensions, discoveries, additions, and improved recovery, less related costs	**3,040**	**—**	**3,040**
Development costs incurred during the period	**561**	**442**	**1,003**
Revisions of previous quantity estimates	**5,438**	**313**	**5,751**
Purchases of minerals in place	**1**	**—**	**1**
Sales of minerals in place	**(560)**	**—**	**(560)**
Accretion of discount	**2,519**	**800**	**3,319**
Net change in income taxes	**(2,254)**	**(1,611)**	**(3,865)**
Other	**(1,282)**	**180**	**(1,102)**
Balance at December 31	**$ 20,173**	**$ 6,283**	**$ 26,456**
2010			
Balance at January 1	$ 11,525	$ 2,028	$ 13,553
Sales and transfers of oil and gas produced, net of production costs	(5,707)	(1,331)	(7,038)
Net changes in prices and production costs	6,645	2,704	9,349
Changes in estimated future development costs	(516)	(185)	(701)
Extensions, discoveries, additions, and improved recovery, less related costs	1,150	—	1,150
Development costs incurred during the period	424	811	1,235
Revisions of previous quantity estimates	4,181	1,235	5,416
Purchases of minerals in place	8	—	8
Sales of minerals in place	(61)	(5)	(66)
Accretion of discount	1,673	421	2,094
Net change in income taxes	(3,001)	(1,305)	(4,306)
Other	666	138	804
Balance at December 31	$ 16,987	$ 4,511	$ 21,498

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Continued)

millions	United States	International	Total
2009			
Balance at January 1	$ 11,403	$ 568	$ 11,971
Sales and transfers of oil and gas produced, net of production costs	(4,035)	(907)	(4,942)
Net changes in prices and production costs	(2,064)	2,999	935
Changes in estimated future development costs	1,196	(243)	953
Extensions, discoveries, additions, and improved recovery, less related costs	717	264	981
Development costs incurred during the period	720	273	993
Revisions of previous quantity estimates	2,389	(26)	2,363
Purchases of minerals in place	206	—	206
Sales of minerals in place	(70)	—	(70)
Accretion of discount	1,642	171	1,813
Net change in income taxes	(192)	(1,044)	(1,236)
Other	(387)	(27)	(414)
Balance at December 31	$ 11,525	$ 2,028	$ 13,553

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL QUARTERLY INFORMATION
(Unaudited)

Quarterly Financial Data

The following shows summary quarterly financial data for 2011 and 2010.

millions except per-share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2011				
Sales revenues	**$ 3,224**	**$ 3,734**	**$ 3,384**	**$ 3,540**
Gains (losses) on divestitures and other, net	**29**	**(58)**	**(185)**	**299**
Deepwater Horizon settlement and related costs	**26**	**9**	**4,042**	**(147)**
Operating income (loss)	**896**	**1,001**	**(3,626)**	**(141)**
Net income (loss)	**237**	**562**	**(3,028)**	**(339)**
Net income attributable to noncontrolling interests	**21**	**18**	**23**	**19**
Net income (loss) attributable to common stockholders	**216**	**544**	**(3,051)**	**(358)**
Earnings per share:				
Net income (loss) attributable to common stockholders—basic	**$ 0.43**	**$ 1.09**	**$ (6.12)**	**$ (0.72)**
Net income (loss) attributable to common stockholders—diluted	**$ 0.43**	**$ 1.08**	**$ (6.12)**	**$ (0.72)**
Average number common shares outstanding—basic	**497**	**498**	**498**	**498**
Average number common shares outstanding—diluted	**499**	**500**	**498**	**498**
2010				
Sales revenues	$ 3,130	$ 2,563	$ 2,516	$ 2,633
Gains (losses) on divestitures and other, net	9	41	34	58
Deepwater Horizon settlement and related costs	—	—	2	13
Operating income (loss)	919	377	196	277
Net income (loss)	728	(28)	(8)	129
Net income attributable to noncontrolling interests	12	12	18	18
Net income (loss) attributable to common stockholders	716	(40)	(26)	111
Earnings per share:				
Net income (loss) attributable to common stockholders—basic	$ 1.44	$ (0.08)	$ (0.05)	$ 0.22
Net income (loss) attributable to common stockholders—diluted	$ 1.43	$ (0.08)	$ (0.05)	$ 0.22
Average number common shares outstanding—basic	493	495	496	496
Average number common shares outstanding—diluted	496	495	496	498

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

EVALUATION AND DISCLOSURE CONTROLS AND PROCEDURES

Anadarko's Chief Executive Officer and Chief Financial Officer performed an evaluation of the Company's disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934. The Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in reports it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that the information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 is accumulated and communicated to the Company's management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of December 31, 2011.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

See *Management's Assessment of Internal Control Over Financial Reporting* under Item 8 of this Form 10-K.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See *Report of Independent Registered Public Accounting Firm* under Item 8 of this Form 10-K.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in Anadarko's internal control over financial reporting during the fourth quarter of 2011 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

See *Anadarko Board of Directors, Corporate Governance—Board of Directors, Corporate Governance—Committees of the Board* and *Section 16(a) Beneficial Ownership Reporting Compliance* in the Anadarko Petroleum Corporation Proxy Statement (Proxy Statement), for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 15, 2012 (to be filed with the Securities and Exchange Commission prior to April 5, 2012), each of which is incorporated herein by reference.

See list of *Executive Officers of the Registrant* under Items 1 and 2 of this Form 10-K, which is incorporated herein by reference.

The Company's Code of Business Conduct and Ethics and the Code of Ethics for the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer (Code of Ethics) can be found on the Company's website located at www.anadarko.com/About/Pages/Governance.aspx. Any stockholder may request a printed copy of the Code of Ethics by submitting a written request to the Company's Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its website. The waiver information will remain on the website for at least 12 months after the initial disclosure of such waiver.

Item 11. Executive Compensation

See *Corporate Governance—Board of Directors—Compensation and Benefits Committee Interlocks and Insider Participation, Corporate Governance—Board of Directors—Director Compensation, Corporate Governance—Director Compensation Table for 2011, Compensation and Benefits Committee Report on 2011 Executive Compensation, Compensation Discussion and Analysis* and *Executive Compensation* in the Proxy Statement, each of which is incorporated herein by reference. The Compensation and Benefits Committee Report and related information incorporated by reference herein shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

See *Security Ownership of Certain Beneficial Owners and Management* in the Proxy Statement, which is incorporated herein by reference.

See *Securities Authorized for Issuance under Equity Compensation Plans* under Item 5 of this Form 10-K, which is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

See *Corporate Governance—Board of Directors* and *Transactions with Related Persons* in the Proxy Statement, each of which is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

See *Independent Auditor* in the Proxy Statement, which is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules

a) EXHIBITS

The following documents are filed as part of this report or incorporated by reference:

(1) The Consolidated Financial Statements of Anadarko Petroleum Corporation are listed on the Index to this report, page 82.

(2) Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description	Original Filed Exhibit	File Number
2(i)	Agreement and Plan of Merger dated as of June 22, 2006, among Anadarko Petroleum Corporation, APC Acquisition Sub, Inc. and Kerr-McGee Corporation	2.2 to Form 8-K filed on June 26, 2006	1-8968
3(i)	Restated Certificate of Incorporation of Anadarko Petroleum Corporation, dated May 22, 2009	3.3 to Form 8-K filed on May 22, 2009	1-8968
(ii)	By-Laws of Anadarko Petroleum Corporation, amended and restated as of May 22, 2009	3.4 to Form 8-K filed on May 22, 2009	1-8968
4(i)	Trustee Indenture dated as of September 19, 2006, Anadarko Petroleum Corporation to The Bank of New York Trust Company, N.A.	4.1 to Form 8-K filed on September 19, 2006	1-8968
(ii)	Second Supplemental Indenture dated October 6, 2006, among Anadarko Petroleum Corporation, Kerr-McGee Corporation, and Citibank, N.A.	4.1 to Form 8-K filed on October 6, 2006	1-8968
(iii)	Ninth Supplemental Indenture dated October 6, 2006, among Anadarko Petroleum Corporation, Kerr-McGee Corporation, and Citibank, N.A.	4.2 to Form 8-K filed on October 6, 2006	1-8968
(iv)	Officers' Certificate of Anadarko Petroleum Corporation, dated March 2, 2009, establishing the 7.625% Senior Notes due 2014 and the 8.700% Senior Notes due 2019	4.1 to Form 8-K filed on March 6, 2009	1-8968
(v)	Form of 7.625% Senior Notes due 2014	4.2 to Form 8-K filed on March 6, 2009	1-8968
(vi)	Form of 8.700% Senior Notes due 2019	4.3 to Form 8-K filed on March 6, 2009	1-8968

Exhibit Number	Description	Original Filed Exhibit	File Number
4(vii)	Officers' Certificate of Anadarko Petroleum Corporation, dated June 9, 2009, establishing the 5.75% Senior Notes due 2014, the 6.95% Senior Notes due 2019 and the 7.95% Senior Notes due 2039	4.1 to Form 8-K filed on June 12, 2009	1-8968
(viii)	Form of 5.75% Senior Notes due 2014	4.2 to Form 8-K filed on June 12, 2009	1-8968
(ix)	Form of 6.95% Senior Notes due 2019	4.3 to Form 8-K filed on June 12, 2009	1-8968
(x)	Form of 7.95% Senior Notes due 2039	4.4 to Form 8-K filed on June 12, 2009	1-8968
(xi)	Officers' Certificate of Anadarko Petroleum Corporation dated March 9, 2010, establishing the 6.200% Senior Notes due 2040	4.1 to Form 8-K filed on March 16, 2010	1-8968
(xii)	Form of 6.200% Senior Notes due 2040	4.2 to Form 8-K filed on March 16, 2010	1-8968
(xiii)	Officers' Certificate of Anadarko Petroleum Corporation dated August 9, 2010, establishing the 6.375% Senior Notes due 2017	4.1 to Form 8-K filed on August 12, 2010	1-8968
(xiv)	Form of 6.375% Senior Notes due 2017	4.2 to Form 8-K filed on August 12, 2010	1-8968
† 10(i)	1998 Director Stock Plan of Anadarko Petroleum Corporation, effective January 30, 1998	Appendix A to DEF 14A filed on March 16, 1998	1-8968
† (ii)	Form of Anadarko Petroleum Corporation 1998 Director Stock Plan Stock Option Agreement	10.1 to Form 8-K filed on November 17, 2005	1-8968
† (iii)	Anadarko Petroleum Corporation Amended and Restated 1999 Stock Incentive Plan	Appendix A to DEF 14A filed on March 18, 2005	1-8968
† (iv)	Form of Anadarko Petroleum Corporation Executive 1999 Stock Incentive Plan Stock Option Agreement	10.2 to Form 8-K filed on November 17, 2005	1-8968
† (v)	Form of Anadarko Petroleum Corporation Non-Executive 1999 Stock Incentive Plan Stock Option Agreement	10.3 to Form 8-K filed on November 17, 2005	1-8968
† (vi)	Form of Stock Option Agreement—1999 Stock Incentive Plan (UK Nationals)	10.4 to Form 8-K filed on November 17, 2005	1-8968

Exhibit Number		Description	Original Filed Exhibit	File Number
†	10(vii)	Amendment to Stock Option Agreement Under the Anadarko Petroleum Corporation 1999 Stock Incentive Plan	10.1 to Form 8-K filed on January 23, 2007	1-8968
†	(viii)	Anadarko Petroleum Corporation 1999 Stock Incentive Plan (Amendment to Performance Unit Agreement)	10.3 to Form 8-K filed on November 13, 2007	1-8968
†	(ix)	Form of Anadarko Petroleum Corporation 1999 Stock Incentive Plan Restricted Stock Agreement	10(b)(xxiv) to Form 10-K for year ended December 31, 1999, filed on March 16, 2000	1-8968
†	(x)	Form of Anadarko Petroleum Corporation 1999 Stock Incentive Plan Restricted Stock Unit Award Letter	10.1 to Form 8-K filed on November 13, 2007	1-8968
†	(xi)	The Approved UK Sub-Plan of the Anadarko Petroleum Corporation 1999 Stock Incentive Plan	10(b)(xxiv) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004	1-8968
†	(xii)	Key Employee Change of Control Contract	10(b)(xxii) to Form 10-K for year ended December 31, 1997, filed on March 18, 1998	1-8968
†	(xiii)	First Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract	10(b) to Form 10-Q for quarter ended September 30, 2000, filed on November 13, 2000	1-8968
†	(xiv)	Form of Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract	10(b)(ii) to Form 10-Q for quarter ended June 30, 2003, filed on August 11, 2003	1-8968
†	(xv)	Form of Key Employee Change of Control Contract (2011)	10(i) to Form 10-Q for quarter ended June 30, 2011, filed on July 27, 2011	1-8968
†	(xvi)	Letter Agreement regarding Post-Retirement Benefits, dated February 16, 2004—Robert J. Allison, Jr.	10(b)(xxxiv) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004	1-8968

Exhibit Number		Description	Original Filed Exhibit	File Number
†	10(xvii)	Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2007)	10(xxii) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010	1-8968
†	(xviii)	Anadarko Retirement Restoration Plan (As Amended and Restated Effective as of November 7, 2007)	10.2 to Form 8-K filed on November 13, 2007	1-8968
†	(xix)	Anadarko Petroleum Corporation Estate Enhancement Program	10(b)(xxxiv) to Form 10-K for year ended December 31, 1998, filed on March 15, 1999	1-8968
†	(xx)	Estate Enhancement Program Agreement between Anadarko Petroleum Corporation and Eligible Executives	10(b)(xxxv) to Form 10-K for year ended December 31, 1998, filed on March 15, 1999	1-8968
†	(xxi)	Estate Enhancement Program Agreements effective November 29, 2000	10(b)(xxxxii) to Form 10-K for year ended December 31, 2000, filed on March 15, 2001	1-8968
†	(xxii)	Anadarko Petroleum Corporation Management Life Insurance Plan, restated November 1, 2002	10(b)(xxxii) to Form 10-K for year ended December 31, 2002, filed on March 14, 2003	1-8968
†	(xxiii)	First Amendment to Anadarko Petroleum Corporation Management Life Insurance Plan, effective June 30, 2003	10(b)(xliii) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004	1-8968
†	(xxiv)	Second Amendment to Anadarko Petroleum Corporation Management Life Insurance Plan, effective January 1, 2008	10(xxix) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010	1-8968
†	(xxv)	Anadarko Petroleum Corporation Officer Severance Plan	10(b)(iv) to Form 10-Q for quarter ended September 30, 2003, filed on November 12, 2003	1-8968

Exhibit Number	Description	Original Filed Exhibit	File Number
† 10(xxvi)	Form of Termination Agreement and Release of All Claims Under Officer Severance Plan	10(b)(v) to Form 10-Q for quarter ended September 30, 2003, filed on November 12, 2003	1-8968
† (xxvii)	Director and Officer Indemnification Agreement	10 to Form 8-K filed on September 3, 2004	1-8968
(xxviii)	$5,000,000,000 Revolving Credit Agreement, dated as of September 2, 2010, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., DnB NorBank ASA, The Royal Bank of Scotland plc, Société Général, and Wells Fargo Bank, N.A., as Syndication Agents, and the several lenders named therein.	10.1 to Form 8-K filed on September 8, 2010	1-8968
(xxix)	First Amendment to Revolving Credit Agreement, dated as of August 3, 2011, to the Revolving Credit Agreement dated as of September 2, 2010, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A. as Administrative Agent, Bank of America, N.A., DnB Nor Bank ASA, The Royal Bank of Scotland plc, Société Générale, and Wells Fargo Bank, N.A., as co-syndication agents, and each of the Lenders from time to time party thereto.	10(i) to Form 10-Q for quarter ended September 30, 2011, filed on October 31, 2011	1-8968
† (xxx)	Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan, effective as of May 20, 2008	10.1 to Form 8-K filed on May 20, 2008	1-8968
† (xxxi)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Stock Option Award Agreement	10.3 to Form 8-K filed on November 13, 2009	1-8968
† (xxxii)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement	10.1 to Form 8-K filed on November 13, 2009	1-8968
† (xxxiii)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Performance Unit Award Agreement	10.2 to Form 8-K filed on November 13, 2009	1-8968
† (xxxiv)	Anadarko Petroleum Corporation 2008 Director Compensation Plan, effective as of May 20, 2008	10.2 to Form 8-K filed on May 27, 2008	1-8968
† (xxxv)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan	10.3 to Form 8-K filed on May 27, 2008	1-8968

Exhibit Number	Description	Original Filed Exhibit	File Number
† 10(xxxvi)	Anadarko Petroleum Corporation Benefits Trust Agreement, amended and restated effective as of November 5, 2008	10(lvi) to Form 10-K for year ended December 31, 2008, filed on February 25, 2009	1-8968
† (xxxvii)	Anadarko Petroleum Corporation Deferred Compensation Plan (as amended and restated effective as of January 1, 2010)	10(xlvi) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010	1-8968
† (xxxviii)	Amended and Restated Employment Agreement between James T. Hackett and Anadarko Petroleum Corporation, dated November 11, 2009	10.4 to Form 8-K filed on November 13, 2009	1-8968
† (xxxix)	Letter Agreement between James T. Hackett and Anadarko Petroleum Corporation, dated February 16, 2012	10.1 to Form 8-K filed on February 21, 2012	1-8968
(xl)	Operating Agreement, dated October 1, 2009, between BP Exploration & Production Inc., as Operator, and MOEX Offshore 2007 LLC, as Non-Operator, as ratified by that certain Ratification and Joinder of Operating Agreement, dated December 17, 2009, by and among BP Exploration & Production Inc., Anadarko Petroleum Corporation (as Non-Operator), Anadarko E&P Company LP (as predecessor in interest to Anadarko Petroleum Corporation), and MOEX Offshore 2007 LLC, together with material exhibits.	10 to Form 10-Q for quarter ended June 30, 2010, filed on August 3, 2010	1-8968
† (xli)	Retention Agreement, dated August 2, 2010	10.1 to Form 8-K filed on August 6, 2010	1-8968
‡ * (xlii)	Confidential Settlement Agreement, Mutual Releases and Agreement to Indemnify, dated October 16, 2011, by and among BP Exploration & Production Inc., Anadarko Petroleum Corporation, Anadarko E&P Company LP, BP Corporation North America Inc. and BP p.l.c.		
† (xliii)	Severance Agreement between R.A. Walker and Anadarko Petroleum Corporation, dated February 16, 2012	10.2 to Form 8-K filed on February 21, 2012	1-8968
*12	Computation of Ratios of Earnings to Fixed Charges and Earnings to Combined Fixed Charges and Preferred Stock Dividends		
*21	List of Subsidiaries		
*23(i)	Consent of KPMG LLP		
*23(ii)	Consent of Miller and Lents, Ltd.		
*24	Power of Attorney		
*31(i)	Rule 13a-14(a)/15d-14(a) Certification—Chief Executive Officer		

Exhibit Number	Description	Original Filed Exhibit	File Number
* 31(ii)	Rule 13a-14(a)/15d-14(a) Certification—Chief Financial Officer		
* 32	Section 1350 Certifications		
* 99	2011 Report of Miller and Lents, Ltd.		
*101 .INS	XBRL Instance Document		
*101 .SCH	XBRL Schema Document		
*101 .CAL	XBRL Calculation Linkbase Document		
*101 .LAB	XBRL Label Linkbase Document		
*101 .PRE	XBRL Presentation Linkbase Document		
*101 .DEF	XBRL Definition Linkbase Document		

† Management contracts or compensatory plans or arrangements required to be filed pursuant to Item 15.

‡ Application has been made to the Securities and Exchange Commission (SEC) for confidential treatment of certain provisions of the exhibit. Omitted material for which confidential treatment has been requested has been filed separately with the SEC.

The total amount of securities of the registrant authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrants and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the SEC, to furnish copies of any or all of such instruments to the SEC.

b) FINANCIAL STATEMENT SCHEDULES

Financial statement schedules have been omitted because they are not required, not applicable, or the information is included in the Company's Consolidated Financial Statements.

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.

ANADARKO PETROLEUM CORPORATION

February 21, 2012

By: /s/ ROBERT G. GWIN

Robert G. Gwin
Senior Vice President, Finance and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 21, 2012.

Name and Signature	Title
(i) Principal executive officer:*	
JAMES T. HACKETT James T. Hackett	Chairman and Chief Executive Officer
(ii) Principal financial officer:	
/s/ ROBERT G. GWIN Robert G. Gwin	Senior Vice President, Finance and Chief Financial Officer
(iii) Principal accounting officer:	
/s/ M. CATHY DOUGLAS M. Cathy Douglas	Vice President and Chief Accounting Officer

(iv) Directors:*

KEVIN P. CHILTON
LUKE R. CORBETT
H. PAULETT EBERHART
PETER J. FLUOR
PRESTON M. GEREN III
JOHN R. GORDON
JAMES T. HACKETT
PAULA ROSPUT REYNOLDS

* Signed on behalf of each of these persons and on his own behalf:

By: /s/ ROBERT G. GWIN

Robert G. Gwin, Attorney-in-Fact