MURPHY OIL CORP /DE
Form 10-K
February 28, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2013

OR

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

For the transition period from ________ to ________

Commission file number 1-8590

MURPHY OIL CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**71-0361522**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**
200 Peach Street, P.O. Box 7000,	
El Dorado, Arkansas	**71731-7000**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (870) 862-6411

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

Title of each class	Name of each exchange on which registered
Common Stock, $1.00 Par Value	**New York Stock Exchange**
Series A Participating Cumulative Preferred Stock Purchase Rights	**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 x 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 x

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 x 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 x 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 registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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

Large accelerated filer	x	Accelerated filer	¨
Non-accelerated filer	¨	Smaller reporting company	¨

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant s most recently completed second fiscal quarter (as of June 30, 2013) $9,733,180,000.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2014 was 183,181,954.

Documents incorporated by reference:

Portions of the Registrant s definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 14, 2014 have been incorporated by reference in Part III herein.

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MURPHY OIL CORPORATION

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PART I

Item 1. BUSINESS

Summary

Murphy Oil Corporation is a worldwide oil and gas exploration and production company, with refining and marketing operations in the United Kingdom that are held for sale. The Company is in the process of transitioning from an integrated oil company to an enterprise entirely focused on oil and gas exploration and production activities. As used in this report, the terms Murphy, Murphy Oil, we, our, its and Company may refer to Murphy Oil Corporation or any one or more of its consolidated subsidiaries.

The Company was originally incorporated in Louisiana in 1950 as Murphy Corporation. It was reincorporated in Delaware in 1964, at which time it adopted the name Murphy Oil Corporation, and was reorganized in 1983 to operate primarily as a holding company of its various businesses. For reporting purposes, Murphy s exploration and production activities are subdivided into five geographic segments, including the United States, Canada, Malaysia, the Republic of the Congo and all other countries. Murphy s refining and marketing activities are now all located in the United Kingdom. As described further in this Form 10-K, Murphy has previously announced its intention to sell its U.K. downstream business. On August 30, 2013, the Company completed the separation of U.S. retail marketing operations with the spin-off of Murphy USA Inc. as a stand-alone company trading on the New York Stock Exchange under the ticker symbol MUSA . Additionally, Corporate activities include interest income, interest expense, foreign exchange effects and administrative costs not allocated to the segments. The Company s corporate headquarters are located in El Dorado, Arkansas.

The information appearing in the 2013 Annual Report to Security Holders (2013 Annual Report) is incorporated in this Form 10-K report as Exhibit 13 and is deemed to be filed as part of this Form 10-K report as indicated under Items 1, 2 and 7.

In addition to the following information about each business activity, data about Murphy s operations, properties and business segments, including revenues by class of products and financial information by geographic area, are provided on pages 25 through 46, F-18 and F-19, F-50 through F-58 and F-60 of this Form 10-K report and on pages 5 and 6 of the 2013 Annual Report.

At December 31, 2013, Murphy had 1,875 employees. Approximately 450 of these employees staff the Company s U.K. refining and marketing business. The separation of Murphy USA Inc. in 2013 reduced the Company s employee count by approximately 1,700 full-time and 6,300 part-time staff.

Interested parties may obtain the Company s public disclosures filed with the Securities and Exchange Commission (SEC), including Form 10-K, Form 10-Q, Form 8-K and other documents, by accessing the Investor Relations section of Murphy Oil Corporation s Web site at www.murphyoilcorp.com.

Exploration and Production

The Company s exploration and production business explores for and produces crude oil, natural gas and natural gas liquids worldwide. The Company s exploration and production management team in Houston, Texas, directs the Company s worldwide exploration and production activities. This business maintains upstream operating offices in other locations around the world, with the most significant of these including Calgary, Alberta and Kuala Lumpur, Malaysia.

During 2013, Murphy s principal exploration and production activities were conducted in the United States by wholly owned Murphy Exploration & Production Company USA (Murphy Expro USA), in Malaysia, Indonesia, Suriname, Australia, Brunei, Cameroon, Vietnam, Equatorial Guinea, Republic of the Congo, and the Kurdistan region of Iraq by wholly owned Murphy Exploration & Production Company International

(Murphy Expro International) and its subsidiaries, and in Western Canada and offshore Eastern Canada by wholly-owned Murphy Oil Company Ltd. (MOCL) and its subsidiaries. Murphy s hydrocarbon production in 2013 was in the United States, Canada, Malaysia, the Republic of the Congo and the United Kingdom. MOCL owns a 5% undivided interest in Syncrude Canada Ltd. in northern Alberta, one of the world s largest producers of synthetic crude oil. In 2013 the Company sold all exploration and production assets in the United Kingdom. The results for these U.K. operations have been reported as discontinued operations in the consolidated financial statements for all periods presented. Unless otherwise indicated, all references to the Company s oil and gas production volumes and proved oil and gas reserves are net to the Company s working interest excluding applicable royalties.

Murphy s worldwide crude oil, condensate and natural gas liquids production in 2013 averaged 135,078 barrels per day, an increase of 20% compared to 2012, and the highest oil volumes produced by the Company over an annual period. The increase was primarily due to higher 2013 oil production in the Eagle Ford Shale area of South Texas. The Company s worldwide sales volume of natural gas averaged 424 million cubic feet (MMCF) per day in 2013, down 14% from 2012 levels. The reduction in natural gas sales volume in 2013 was primarily attributable to lower gas production in the Tupper area in Western Canada, where further development drilling was voluntarily curtailed due to low local natural gas sales prices, and in Malaysia at the Kikeh field where the third-party gas receiving facility had more downtime in 2013. Total worldwide 2013 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 205,719 barrels per day, an increase of 6% compared to 2012, and also a Company record for a single year.

Total production in 2014 is currently expected to average between 235,000 and 240,000 barrels of oil equivalent per day. The projected production increase of 14% to 17% in 2014 includes approximately a 23% to 26% increase in oil and liquids volumes. The overall anticipated production increase in 2014 is primarily related to higher oil volumes expected in the Eagle Ford Shale area as the Company continues its drilling program in the play. Additionally, Malaysian oil production is anticipated to rise in 2014 due to ramp-up of production in Blocks SK 309/311 following start-up of four new oil fields in the second half of 2013, full field start up at the Kakap-Gumusut field and new production at the Siakap North-Petai field. These higher oil volumes are expected to more than offset production declines in 2013 at other producing fields. Natural gas production is expected to decline slightly in 2014 as start up of a new field in the Gulf of Mexico and higher volumes in Malaysia do not fully offset the effects of production decline associated with continued voluntary curtailment of development drilling activities in the Tupper area in northeast British Columbia caused by historically depressed North American natural gas prices.

United States

In the United States, Murphy primarily has production of oil and/or natural gas from fields in the Eagle Ford Shale area of South Texas and in the deepwater Gulf of Mexico. The Company produced approximately 48,400 barrels of oil per day and 53 MMCF of natural gas per day in the U.S. in 2013. These amounts represented 36% of the Company s total worldwide oil and 13% of worldwide natural gas production volumes. During 2013, approximately 31% of total U.S. hydrocarbon production was produced at fields in the Gulf of Mexico. Approximately two-thirds of Gulf of Mexico production in 2013 was derived from three fields, including Medusa, Front Runner and Thunder Hawk. The Company holds a 60% interest in Medusa in Mississippi Canyon Blocks 538/582, and 62.5% working interests in the Front Runner field in Green Canyon Blocks 338/339 and the Thunder Hawk field in Mississippi Canyon Block 734. Total daily production in the Gulf of Mexico in 2013 was 12,500 barrels of oil and 31 MMCF of natural gas. Total production in the Gulf of Mexico in 2014 is expected to increase to about 15,000 barrels of oil per day and approximately 42 MMCF per day of natural gas; the increase in 2014 is primarily related to the anticipated start-up of the Dalmatian field in DeSoto Canyon Blocks 4 and 48. The Company has a 70% working interest in the Dalmatian properties. At December 31, 2013, Murphy has total proved reserves for Gulf of Mexico fields of 29.1 million barrels of oil and 77 billion cubic feet of natural gas.

The Company has acquired rights to approximately 164 thousand gross acres in South Texas in the Eagle Ford Shale unconventional oil and gas play. The Company currently has eight active drilling rigs and three hydraulic

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fracturing teams operating in the Eagle Ford in early 2014. Current plans are to drill approximately 170 wells in the play in 2014. The Company is concentrating drilling efforts in the areas of the Eagle Ford where oil is the primary hydrocarbon produced. Total 2013 oil and natural gas production in the Eagle Ford area was approximately 35,600 barrels per day and 21 MMCF per day, respectively. On a barrel of oil equivalent basis, Eagle Ford production accounted for 68% of total U.S. production volumes in 2013. Due to ongoing drilling and infrastructure development activities, 2014 production in the Eagle Ford Shale is expected to increase to approximately 53,000 barrels of oil per day and 24 MMCF of natural gas per day. At December 31, 2013, the Company s proved reserves in the Eagle Ford Shale area totaled 185.3 million barrels of oil and 104 billion cubic feet of natural gas. Total U.S. proved oil and natural gas reserves at December 31, 2013 were 214.7 million barrels and 185 billion cubic feet, respectively.

Canada

In Canada, the Company owns an interest in three significant non-operated assets the Hibernia and Terra Nova fields offshore Newfoundland in the Jeanne d Arc Basin and Syncrude Canada Ltd. in northern Alberta. In addition, the Company owns interests in one heavy oil area and two significant natural gas areas in the Western Canadian Sedimentary Basin (WCSB).

Murphy has a 6.5% working interest in Hibernia, while at Terra Nova the Company s working interest is 10.475%. Oil production in 2013 was about 5,600 barrels of oil per day at Hibernia and 3,500 barrels per day at Terra Nova. Hibernia production increased slightly in 2013 due to new wells brought on stream, while Terra Nova production was significantly higher in 2013 due to an extended period of downtime for maintenance during the second half of 2012. Oil production for 2014 at Hibernia and Terra Nova is anticipated to be approximately 5,000 barrels per day and 3,800 barrels per day, respectively. Total proved oil reserves at December 31, 2013 at Hibernia and Terra Nova were approximately 14.3 million barrels and 8.4 million barrels, respectively.

Murphy owns a 5% undivided interest in Syncrude Canada Ltd., a joint venture located about 25 miles north of Fort McMurray, Alberta. Syncrude utilizes its assets, which include three coking units, to extract bitumen from oil sand deposits and to upgrade this bitumen into a high-value synthetic crude oil. Production in 2013 was about 12,900 net barrels of synthetic crude oil per day and is expected to average about 13,700 barrels per day in 2014. Total proved reserves for Syncrude at year-end 2013 were 117 million barrels.

Daily production in 2013 in the WCSB averaged 9,200 barrels of mostly heavy oil and 175 MMCF of natural gas. The Company has 133 thousand net acres of mineral rights in the Montney area, described as Tupper and Tupper West. Natural gas production commenced at Tupper in December 2008, while Tupper West production started up in February 2011. The Company has 326 thousand net acres of mineral rights in the Seal area located in the Peace River oil sands area of Northwest Alberta. Oil and natural gas daily production for 2014 in Western Canada, excluding Syncrude, is expected to be about 9,000 barrels and 147 MMCF, respectively. The decrease in natural gas volumes in 2014 is primarily the result of natural well decline due to continued curtailment of development drilling at Tupper West and Tupper associated with depressed North American natural gas prices. Total WCSB proved oil and natural gas reserves at December 31, 2013, excluding Syncrude, were 16 million barrels and 549 billion cubic feet, respectively.

Malaysia

In Malaysia, the Company has majority interests in seven separate production sharing contracts (PSCs). The Company serves as the operator of all these areas other than the unitized Kakap-Gumusut field. The production sharing contracts cover approximately 2.87 million gross acres. Murphy has an 85% interest in oil and natural gas discoveries made in two shallow-water blocks, SK 309 and SK 311, offshore Sarawak. The Company brought on production from five new fields Serendah, Patricia, South Acis, Permas and Merapuh during the second half of 2013. These fields are producing through a series of new offshore platforms and pipelines tying back to the Company s existing infrastructure. About 11,000 barrels of oil per day were produced in 2013 at

Blocks SK 309/311, almost evenly split between the West Patricia field and other Sarawak fields. Oil production in 2014 at fields in Blocks SK 309/311 is anticipated to total about 21,900 barrels of oil per day, with the increase associated with a full year of production at the new Sarawak oil fields. The Company has a gas sales contract for the Sarawak area with PETRONAS, the Malaysian state-owned oil company, and has an ongoing multi-phase development plan for several natural gas discoveries on these blocks. The gas sales contract, including an extension option exercised in 2012, allows for gross sales volumes of up to 250 MMCF per day through September 2021. Total net natural gas sales volume offshore Sarawak was about 165 MMCF per day during 2013 (gross 239 MMCF per day). Sarawak net natural gas sales volumes are anticipated to be approximately 159 MMCF per day in 2014, with the reduction primarily attributable to an entitlement change to the Company. Total proved reserves of oil and natural gas at December 31, 2013 for Blocks SK 309/311 were 23 million barrels and 331 billion cubic feet, respectively.

The Company made a major discovery at the Kikeh field in deepwater Block K, offshore Sabah, Malaysia, in 2002 and added another discovery at Kakap in 2004. An additional discovery was made in Block K at Siakap North-Petai in 2009. In 2006, the Company relinquished a portion of Block K and was granted a 60% interest in an extension of a portion of Block K. In 2011, the Company relinquished the remainder of Block K except for the discovered fields, which include Kikeh, Kakap-Gumusut and Siakap North-Petai. Total gross acreage held by the Company in Block K as of December 31, 2013 was 80,000 acres. Production volumes at Kikeh averaged 40,400 barrels of oil per day during 2013. Oil production at Kikeh is anticipated to average approximately 29,000 barrels per day in 2014. The oil reduction in 2014 is primarily attributable to planned downtime for equipment installation to allow Siakap North-Petai volumes to be produced through the Kikeh facility. The Company has a Kikeh field natural gas sales contract with PETRONAS that calls for gross sales volumes of up to 120 MMCF per day. Gas production at Kikeh will continue until the earlier of lack of available commercial quantities of Kikeh associated gas reserves or expiry of the Block K production sharing contract. Natural gas production at Kikeh in 2013 totaled approximately 30 MMCF per day. Daily gas production in 2014 at Kikeh is expected to average about 40 MMCF per day. The 2014 gas increase at Kikeh is due to less anticipated downtime at the onshore receiving facility owned by PETRONAS. The Kakap-Gumusut field in Block K is operated by another company. The Kakap field is being jointly developed with the Gumusut field owned by others and Murphy holds a 14% working interest in the unitized development. Early production began in late 2012 at Kakap-Gumusut, via a temporary tie-back to the Kikeh production facility. Kakap-Gumusut development activities continued during 2013. The primary Kakap-Gumusut production facility is expected to be completed in 2014, whereby oil production can be ramped up to a significantly higher volume. Kakap-Gumusut oil production in 2013 totaled 2,400 net barrels of oil per day. Kakap-Gumusut production in 2014 is expected to average 8,100 barrels of oil per day. The Siakap North-Petai oil discovery is being developed as a unitized area operated by Murphy, with a tie-back to the Kikeh field. Production is expected to begin in 2014 at Siakap North-Petai with a daily average anticipated of 7,400 barrels of oil and 5 MMCF of gas during the year. Total proved reserves booked in Block K as of year-end 2013 were 102 million barrels of oil and 75 billion cubic feet of natural gas.

The Company also has an interest in deepwater Block H offshore Sabah. In early 2007, the Company announced a significant natural gas discovery at the Rotan well in Block H. Since 2007, the Company has followed up Rotan with several other nearby discoveries. In March 2008, the Company renewed the contract for Block H at a 60% interest while retaining 80% interest in the Rotan and Biris discoveries. In 2011, the Company relinquished 30% of Block H, but retained all discovered fields. Total gross acreage held by the Company at year-end 2013 in Block H was 1.40 million acres. In early 2014, PETRONAS and the Company sanctioned a Floating Liquefied Natural Gas project for Block H, and agreed terms for sales of natural gas to be produced with prices tied to an oil index.

The Company has a 60% interest in a gas holding area covering approximately 2,000 gross acres in Block P. This interest can be retained until January 2018. The remainder of Block P was relinquished in early 2013.

In May 2013, the Company acquired an 85% working interest in shallow-water Malaysia Block SK 314A. The production sharing contract covers a three-year exploration period. Total gross acreage for this block is 1.12 million acres. The Company s 15% partner in this concession is being carried by Murphy through the minimum work program. Geophysical studies were performed during 2013 and the first exploration wells are planned in 2015.

Murphy has a 75% interest in gas holding agreements for Kenarong and Pertang discoveries made in Block PM 311 located offshore peninsular Malaysia. Development options are being studied for these discoveries.

Australia

The Company holds six exploration permits in Australia and serves as operator of four of them. A 40% interest in Block AC/P36 in the Browse Basin offshore northwestern Australia was acquired in 2007 and one unsuccessful well has been drilled. The Company renewed the exploration permit for an additional five years and in that process relinquished 50% of the gross acreage; the license now covers 482 thousand gross acres. Murphy increased its working interest in the remaining acreage to 100% in 2012 and subsequently farmed out a 50% working interest and operatorship.

Block NT/P80 in the Bonaparte Basin, offshore northwestern Australia, was acquired in June 2009 and covers approximately 1.20 million gross acres. The Company s working interest is 70% and it acquired 3D seismic data over this block during 2013.

In May 2012, Murphy was awarded permit WA-476-P in the Carnarvon Basin, offshore Western Australia. The Company holds 100% working interest in the permit which covers 177,000 gross acres. The work commitment includes seismic data reprocessing and geophysical work.

In August 2012, Murphy was awarded permit WA-481-P in the Perth Basin, offshore Western Australia. The permit covers approximately 4.30 million gross acres, with water depths ranging from 20 to 300 meters. The Company holds a 40% working interest. The work commitment calls for 2D and 3D seismic acquisition and processing, geophysical work and three exploration wells.

In November 2012, Murphy acquired a 20% non-operated working interest in permit WA-408-P in the Browse Basin. The permit comprises approximately 417,000 gross acres. Two wells were drilled on the license in 2013. The first well found hydrocarbon but was deemed unsuccessful and was written off to expense. The second well was also unsuccessful.

In October 2013, the Company was awarded permit EPP 43 in the Ceduna Basin, offshore South Australia. The Company operates the concession and holds a 50% working interest in the permit which covers approximately 4.08 million gross acres. The exploration permit covers six years and requires commitments for 2D and 3D seismic.

Indonesia

The Company currently has interests in four exploration licenses in Indonesia and serves as operator of all these concessions. In November 2008, Murphy entered into a production sharing contract in the Semai II block offshore West Papua. The Company has a 28.3% interest in the block which covers about 543 thousand gross acres after a required partial relinquishment of acreage during 2012. The permit calls for a 3D seismic program and three exploration wells. The 3D seismic was acquired in 2010, while the first exploration well in the Semai II block was drilled in early 2011 and was unsuccessful. The second and third exploration wells are planned for 2014.

In December 2010, Murphy entered into a production sharing contract in the Wokam II block offshore West Papua, Moluccas and Papua. Murphy has a 100% interest in the block which covers 918 thousand gross acres. The three-year work commitment calls for seismic acquisition and processing, which the Company completed in 2013.

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In November 2011, the Company acquired a 100% interest in a production sharing contract in the Semai IV block offshore West Papua. The concession includes 873 thousand gross acres. The agreement calls for work commitments of seismic acquisition and processing which are currently part of the Company s 2014 exploration plan.

In May 2008, the Company entered into a production sharing contract at a 100% interest in the South Barito block in south Kalimantan on the island of Borneo. Following contractually mandated acreage relinquishment in 2012, the block now covers approximately 745 thousand gross acres. The contract permits a six-year exploration term with an optional four-year extension. The Company currently anticipates exiting this block in 2014.

Brunei

In late 2010, the Company entered into two production sharing agreements for properties offshore Brunei. The Company has a 5% working interest in Block CA-1 and a 30% working interest in Block CA-2. The CA-1 and CA-2 blocks cover 1.44 million and 1.49 million gross acres, respectively. Three successful wells were drilled in Block CA-1 in 2012 and three wells were successfully drilled in Block CA-2 in 2013. The partnership group is evaluating development options for Block CA-2.

Vietnam

In November 2012, the Company signed a production sharing contract with Vietnam National Oil and Gas Group and PetroVietnam Exploration Production Company, whereby it acquired 65% interest and operatorship of Blocks 144 and 145. The blocks cover approximately 4.42 million gross acres and are located in the outer Phu Khanh Basin. The Company licensed existing 2D seismic for these blocks in 2013.

In late 2012, the Company was granted Vietnam s government approval to acquire a 60% working interest and operatorship of Block 11-2/11 and the production sharing contract was signed in June 2013. The block covers 677 thousand gross acres. The Company acquired 3D seismic and performed other geological and geophysical studies in this block in 2013.

In early 2014, the Company farmed into Block 13-03. The Company has a 20% working interest in this concession which covers 853,000 gross acres. Murphy is currently scheduled to spud a well in the block in mid 2014.

Suriname

In December 2011, Murphy signed a production sharing contract with Suriname s state oil company, Staatsolie Maatschappij Suriname N.V. (Staatsolie), whereby it acquired a 100% working interest and operatorship of Block 48 offshore Suriname. The block encompasses 794 thousand gross acres with water depths ranging from 1,000 to 3,000 meters. The 30-year contract is divided into an exploration period and one or more development and production periods, and may be extended with mutual agreement of Murphy and Staatsolie. There are three phases of the exploration period, with each divided into two-year terms, thereby allowing the Company to withdraw from the contract or enter into the next phase. Minimum work obligations vary during each exploration phase and may require either seismic data acquisition or drilling of an exploratory well. Staatsolie has the right to join in the development and production of each commercial field within the contract area with up to a 20% participation. In early 2014, Murphy farmed out a portion of its working interest in Block 48, thereby reducing its interest from 100% to 50%.

Cameroon

In October 2011, Murphy was granted government approval to acquire a 50% working interest and operatorship of the Ntem concession. The working interest was acquired through a farm-out agreement of the existing production sharing contract. The Ntem block, situated in the Douala Basin offshore Cameroon, encompasses

573 thousand gross acres, with water depths ranging from 300 to 1,900 meters. The concession was in force majeure until January 2014. With force majeure lifted, there are 15 months of the first renewal period remaining which can be extended for a further two years under the second renewal period option in the contract. Each of the renewal periods requires a minimum work obligation involving the drilling of exploratory wells. The Company spud a well on the Ntem prospect in February 2014.

In 2012, Murphy acquired a 50% non-operated interest in the Elombo production sharing contract, immediately adjacent to the Ntem concession. The Elombo block, situated in the Douala Basin offshore Cameroon, between the shoreline and the Ntem block, encompasses 594 thousand gross acres with water depths ranging up to 1,100 meters. The initial exploration period was for three years and was scheduled to end in March 2013. Prior to the end of the initial period the Company drilled a shallow well which was unsuccessful. The initial exploration period was extended for two years through March 2015 with an obligation for one well. The exploration period may be extended one more time for an additional two years with a further one-well obligation. Murphy drilled an unsuccessful deepwater well in the block in 2013 as part of the obligations under the agreement.

Equatorial Guinea

In December 2012, Murphy signed a production sharing contract for block W offshore Equatorial Guinea. Murphy has a 45% working interest and operates the block. The government ratified the contract early in 2013. The block is located offshore mainland Equatorial Guinea and encompasses 557 thousand gross acres with water depths ranging from 60 to 2,000 meters. The initial exploration period of five years is divided into two sub-periods, a first sub-period of three years and a second sub-period of two years. The first sub-period may be extended one year and with this extension is the obligation to drill one well. Entering the second sub-period has the obligation to drill an additional well. In early 2014, Murphy completed acquisition of new 3D seismic over the entire block. Using the available seismic data, the Company is evaluating the potential for drilling.

Republic of the Congo

The Company formerly had interests in Production Sharing Agreements (PSA) covering two offshore blocks in Republic of the Congo Mer Profonde Sud (MPS) and Mer Profonde Nord (MPN). In 2005, Murphy made an oil discovery at Azurite Marine #1 in the southern block, MPS. Total oil production in 2013 averaged 1,000 barrels per day at Azurite for the Company s 50% interest. The field was shutdown and ceased production in the fourth quarter of 2013 and abandonment operations were well advanced in early 2014. Abandonment and other exit charges of $82.5 million were recorded in the fourth quarter of 2013 associated with the earlier than anticipated shutdown of the Azurite field. The MPN block exploration license expired on December 30, 2012 and MPS block exploration license expired in March 2013. Murphy will relinquish the Azurite field upon completion of abandonment in 2014.

Iraq

In late 2010, the Company finalized an agreement with the Kurdistan Regional Government (KRG) in Iraq to acquire an interest in the Central Dohuk block. The Company operated and held a 50% interest in the block. The Central Dohuk block covered approximately 153 thousand gross acres and is located in the Dohuk area of the Kurdistan region in Iraq. The Company shot seismic in 2011 and drilled an unsuccessful exploration well in 2012. The Company relinquished this exploration license during 2013.

United Kingdom Discontinued Operations

Murphy produced oil and natural gas in the United Kingdom sector of the North Sea for many years. In 2013, Murphy sold all of its oil and gas properties in the U.K. with an after-tax gain of $216.1 million on the sale. Total 2013 production in the U.K. on a full-year basis amounted to about 600 barrels of oil per day and 1 MMCF of natural gas per day. The Company has accounted for U.K. oil and gas activities as discontinued operations for all periods presented.

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Ecuador Discontinued Operations

Murphy sold its 20% working interest in Block 16, Ecuador in March 2009. The Company has accounted for all Ecuador operations as discontinued operations. In October 2007, the government of Ecuador passed a law that increased its share of revenue for sales prices that exceed a base price (about $23.36 per barrel at December 31, 2008) from 50% to 99%. The government had previously enacted a 50% revenue sharing rate in April 2006. The Company initiated arbitration proceedings against the government in one international jurisdiction claiming that the government did not have the right under the contract to enact the revenue sharing provision. In 2010, the arbitration panel determined that it lacked jurisdiction over the claim due to technicalities. The arbitration was refiled in 2011 under a different international jurisdiction and present activities involve preparation for a hearing on the merits of the filing. The arbitration proceeding is likely to take many months to reach conclusion. The Company s total claim in the arbitration process is approximately $118 million.

Proved Reserves

Total proved oil and natural gas reserves as of December 31, 2013 are presented in the following table.

	Proved Reserves		
	Oil	Synthetic Oil	Natural Gas
	(millions of barrels)		(billions of cubic feet)
Proved Developed Reserves:			
United States	88.9		112.6
Canada	31.6	117.0	384.0
Malaysia	66.6		289.6
Total proved developed reserves	187.1	117.0	786.2
Proved Undeveloped Reserves:			
United States	125.8		72.4
Canada	7.2		178.8
Malaysia	58.5		116.2
Total proved undeveloped reserves	191.5		367.4
Total proved reserves	378.6	117.0	1,153.6

Murphy Oil s proved undeveloped reserves increased during 2013 as presented in the table that follows:

(Millions of oil equivalent barrels)	
Proved undeveloped reserves:	
Beginning of year	218.9
Revisions of previous estimates	49.3
Extension and discoveries	54.1
Conversion to proved developed reserves	(52.2)
Sales of properties	(17.4)
End of year	252.7

Murphy s total proved undeveloped reserves at December 31, 2013 increased 33.8 million barrels of oil equivalent (MMBOE) from a year earlier. The conversion of non-proved reserves to newly reported proved undeveloped reserves reported in the table as extensions and discoveries during 2013 was predominantly attributable to drilling in the Eagle Ford Shale area of South Texas as this area had active development work ongoing during the year. The majority of proved undeveloped reserves additions associated with revisions of previous estimates was the result of development drilling and/or well performance at the Eagle Ford Shale, the Kikeh field in Malaysia and offshore

Eastern Canada. The majority of the proved undeveloped reserves migration to the proved developed category occurred in the Eagle Ford Shale. The Company sold all of its U.K. oil and gas properties during the first half of 2013 which led to a reduction of proved undeveloped reserves of 17.4 million barrels equivalent during the year. The Company spent approximately $1.2 billion in 2013 to convert proved undeveloped reserves to proved developed reserves. The Company expects to spend about $1.1 billion in 2014, $1.0 billion in 2015 and $1.1 billion in 2016 to move currently undeveloped proved reserves to the developed category. The anticipated level of spend in 2014 includes significant drilling in several locations, primarily in the Eagle Ford Shale area. In computing MMBOE, natural gas is converted to equivalent barrels of oil using a ratio of six thousand cubic feet (MCF) to one barrel of oil.

At December 31, 2013, proved reserves are included for several development projects, including oil developments at the Eagle Ford Shale in South Texas and the Kakap-Gumusut, Kikeh and Siakap North-Petai fields, offshore Sabah, Malaysia as well as a natural gas development offshore Sarawak, Malaysia. Total proved undeveloped reserves associated with various development projects at December 31, 2013 were approximately 253 MMBOE, which is 37% of the Company s total proved reserves. Certain of these development projects have proved undeveloped reserves that will take more than five years to bring to production. Three such projects have significant levels of such proved undeveloped reserves. The Company operates a deepwater field in the Gulf of Mexico that has two undeveloped locations that exceed this five-year window. Total reserves associated with the two wells amount to less than 1% of the Company s total proved reserves at year-end 2013. The development of certain of this field s reserves stretches beyond five years due to limited well slots available on the production platform, thus making it necessary to wait for depletion of other wells prior to initiating further development of these two locations. The Kakap-Gumusut field oil development project has undeveloped proved reserves that make up 5% of the Company s total proved reserves at year-end 2013. This non-operated project has taken longer than five years to develop due to long lead-time equipment required to complete the development process in the deep waters offshore Sabah Malaysia. Full field start up is expected in 2014. The third project that will take more than five years to develop is offshore Malaysia and makes up approximately 2% of the Company s total proved reserves at year-end 2013. This project is an extension of the Sarawak natural gas project and should be on production in 2014 once current project production volumes decline.

Murphy Oil s Reserves Processes and Policies

The Company employs a Manager of Corporate Reserves (Manager) who is independent of the Company s oil and gas management. The Manager reports to a Vice President of Murphy Oil Corporation, who in turn reports directly to the President and Chief Executive Officer of Murphy Oil. The Manager makes presentations to the Board of Directors periodically about the Company s reserves. The Manager reviews and discusses reserves estimates directly with the Company s reservoir engineering staff in order to make every effort to ensure compliance with the rules and regulations of the SEC and industry. The Manager coordinates and oversees reserves audits. These audits are performed annually and target coverage of approximately one-third of Company reserves each year. The audits are performed by the Manager and qualified engineering staff from areas of the Company other than the area being audited. The Manager may also utilize qualified independent reserves consultants to assist with the internal audits or to perform separate audits as considered appropriate.

Each significant exploration and production office maintains one or more Qualified Reserve Estimators (QRE) on staff. The QRE is responsible for estimating and evaluating reserves and other reserves information for his or her assigned area. The QRE may personally make the estimates and evaluations of reserves or may supervise and approve the estimation and evaluation thereof by others. A QRE is professionally qualified to perform these reserves estimates due to having sufficient educational background, professional training and professional experience to enable him or her to exercise prudent professional judgment. Normally, this requires a minimum of three years practical experience in petroleum engineering or petroleum production geology, with at least one year of such experience being in the estimation and evaluation of reserves, and either a bachelors or advanced degree in petroleum engineering, geology or other discipline of engineering or physical science from a college or university of recognized stature, or the equivalent thereof from an appropriate government authority or professional organization.

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Larger offices of the Company also employ a Regional Reserves Coordinator (RRC) who supervises the local QREs. The RRC is usually a senior QRE that has the primary responsibility for coordinating and submitting reserves information to senior management.

The Company s QREs maintain files containing pertinent data regarding each significant reservoir. Each file includes sufficient data to support the calculations or analogies used to develop the values. Examples of data included in the file, as appropriate, include: production histories; pertinent drilling and workover histories; bottom hole pressure data; volumetric, material balance, analogy or other pertinent reserve estimation data; production performance curves; narrative descriptions of the methods and logic used to determine reserves values; maps and logs; and a signed copy of the conclusion of the QRE stating, that in their opinion, the reserves have been calculated, reviewed, documented and reported in compliance with the regulations and guidelines contained in the reserves training manual. The Company s reserves are maintained in an industry recognized reservoir engineering software system, which has adequate access controls to avoid the possibility of improper manipulation of data. When reserves calculations are completed by QREs and appropriately reviewed by RRCs and the Manager, the conclusions are reviewed and discussed with the head of the Company s exploration and production business and other senior management as appropriate. The Company s Controller s department is responsible for preparing and filing reserves schedules within Form 10-K.

Murphy provides annual training to all company reserves estimators to ensure SEC requirements associated with reserves estimation and associated Form 10-K reporting are fulfilled. The training includes materials provided to each participant that outlines the latest guidance from the SEC as well as best practices for many engineering and geologic matters related to reserves estimation.

Qualifications of Manager of Corporate Reserves

The Company believes that it has qualified employees preparing oil and gas reserves estimates. Mr. F. Michael Lasswell serves as Corporate Reserves Manager after joining the Company in 2012. Prior to joining Murphy, Mr. Lasswell was employed as a Regional Coordinator of reserves at a major integrated oil company. He worked in several capacities in the reservoir engineering department with the oil company from 2002 to 2012. Mr. Lasswell earned a Bachelors of Science degree in Civil Engineering and a Masters of Science degree in Geotechnical Engineering from Brigham Young University. Mr. Lasswell has experience working in the reservoir engineering field in numerous areas of the world, including the North Sea, the U.S. Arctic, the Middle East and Asia Pacific. He serves on the Society of Petroleum Engineers (SPE) Oil and Gas Reserves Committee (OGRC) and is also co-author of a paper on the Recognition of Reserves which was published by the SPE. Mr. Lasswell has also attended numerous industry training courses.

More information regarding Murphy s estimated quantities of proved oil and gas reserves for the last three years are presented by geographic area on pages F-52 through F-55 of this Form 10-K report. Murphy has not filed and is not required to file any estimates of its total proved oil or gas reserves on a recurring basis with any federal or foreign governmental regulatory authority or agency other than the U.S. Securities and Exchange Commission. Annually, Murphy reports gross reserves of properties operated in the United States to the U.S. Department of Energy; such reserves are derived from the same data from which estimated proved reserves of such properties are determined.

Crude oil, condensate and gas liquids production and sales, and natural gas sales by geographic area with weighted average sales prices for each of the seven years ended December 31, 2013 are shown on page 5 of the 2013 Annual Report. In 2013, the Company s production of oil and natural gas represented approximately 0.1% of worldwide totals.

Production expenses for the last three years in U.S. dollars per equivalent barrel are discussed beginning on page 32 of this Form 10-K report. For purposes of these computations, natural gas sales volumes are converted to equivalent barrels of oil using a ratio of six MCF of natural gas to one barrel of oil.

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Supplemental disclosures relating to oil and gas producing activities are reported on pages F-50 through F-60 of this Form 10-K report.

At December 31, 2013, Murphy held leases, concessions, contracts or permits on developed and undeveloped acreage as shown by geographic area in the following table. Gross acres are those in which all or part of the working interest is owned by Murphy. Net acres are the portions of the gross acres attributable to Murphy s interest.

	Developed		Undeveloped		Total	
Area (Thousands of acres)	Gross	Net	Gross	Net	Gross	Net
United States Onshore	83	70	96	89	179	159
Gulf of Mexico	12	5	1,040	651	1,052	656
Alaska	4	1	8		12	1
Total United States	99	76	1,144	740	1,243	816
Canada Onshore, excluding oil sands	78	78	739	578	817	656
Offshore	105	9	43	2	148	11
Oil sands Syncrude	96	5	160	8	256	13
Total Canada	279	92	942	588	1,221	680
Malaysia	290	239	2,582	1,847	2,872	2,086
Australia			10,666	5,102	10,666	5,102
Brunei			2,934	519	2,934	519
Indonesia			3,079	2,690	3,079	2,690
Vietnam			5,098	3,280	5,098	3,280
Cameroon			1,167	584	1,167	584
Equatorial Guinea			557	251	557	251
Suriname			794	636	794	636
Republic of the Congo			11	6	11	6
Iraq			153	76	153	76
Spain			36	6	36	6
Totals	668	407	29,163	16,325	29,831	16,732

Certain acreage held by the Company will expire in the next three years. Scheduled expirations in 2014 include 745 thousand net acres in South Barito Indonesia; 123 thousand net acres in Semai II Indonesia; 38 thousand net acres in Semai IV Indonesia; 196 thousand net acres in the United States; 53 thousand net acres in Western Canada; 76 thousand net acres in the Kurdistan region of Iraq; 9 thousand net acres in SK Block 309 in Malaysia; and 36 thousand net acres in Block PM 311 Malaysia. In 2015, scheduled expiring acreage includes 57 thousand net acres in SK Blocks 309 and 311 in Malaysia; 420 thousand net acres in NT/P80 Australia; 42 thousand net acres in WA-408-P Australia; 281 thousand net acres in Western Canada; 53 thousand net acres in the United States; 146 thousand net acres in Cameroon; and 636 thousand net acres in Block 48 Suriname. Scheduled acreage expirations in 2016 include 837 thousand net acres in Block H in Malaysia; 957 thousand net acres in Block SK 314A in Malaysia; 734 thousand net acres in Wokam II Block in Indonesia; 575 thousand net acres in Blocks 144 and 145 in Vietnam; 81 thousand net acres in Block 11-2/11 in Vietnam; 98 thousand net acres in the United States; and 93 thousand net acres in Western Canada.

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As used in the three tables that follow, gross wells are the total wells in which all or part of the working interest is owned by Murphy, and net wells are the total of the Company s fractional working interests in gross wells expressed as the equivalent number of wholly owned wells. An exploratory well is drilled to find and produce crude oil or natural gas in an unproved area and includes delineation wells which target a new reservoir in a field known to be productive or to extend a known reservoir beyond the proved area. A development well is drilled within the proved area of an oil or natural gas reservoir that is known to be productive.

The following table shows the number of oil and gas wells producing or capable of producing at December 31, 2013.

	Oil Wells		Gas Wells	
Country	Gross	Net	Gross	Net
United States	384	320	23	16
Canada	423	380	178	178
Malaysia	60	49	46	39
Totals	867	749	247	233

Murphy s net wells drilled in the last three years are shown in the following table.

	United States		Canada		Malaysia		Other		Totals	
	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry
2013										
Exploratory	**15.2**	**0.4**		**1.0**			**0.9**	**1.4**	**16.1**	**2.8**
Development	**161.2**		**22.0**	**19.0**	**16.3**				**199.5**	**19.0**
2012										
Exploratory	15.2	0.1		1.0	2.8	0.8		2.9	18.0	4.8
Development	92.2		106.5	21.5	20.5				219.2	21.5
2011										
Exploratory	17.9		1.0	4.9	0.9			2.3	19.8	7.2
Development	14.3	0.8	117.5	6.0	12.8		0.5		145.1	6.8

The Canadian dry development wells shown above are stratigraphic wells used to obtain information about Seal area heavy oil reservoirs. These wells will not be used to produce oil.

Murphy s drilling wells in progress at December 31, 2013 are shown in the following table. The year-end well count includes wells awaiting various completion operations. The U.S. net wells included below are essentially all located in the Eagle Ford Shale area of South Texas.

	Exploratory		Development		Total	
Country	Gross	Net	Gross	Net	Gross	Net
United States			88	74.7	88	74.7
Canada			3	3.0	3	3.0
Totals			91	77.7	91	77.7

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Refining and Marketing Discontinued Operations

The Company completed the separation of its former retail marketing business in the United States during the year. On August 30, 2013, the Company spun-off the U.S. downstream business through a distribution of 100% of the shares of this Company to shareholders of Murphy Oil. The new stand-alone, publicly owned company, which is now known as Murphy USA Inc. (MUSA), is listed on the New York Stock Exchange under the ticker symbol MUSA .

The Company has also announced its intention to sell its refining and marketing (downstream) business in the United Kingdom. The sale of the U.K. downstream business is subject to inherent risks and uncertainties. Factors that could cause this forecasted event not to occur are described in Item 1A on page 18 of this Form 10-K report. All of the results of the U.S. and U.K. downstream businesses have been reported as discontinued operations for all periods presented in this report.

Murco Petroleum Limited (Murco), a wholly owned U.K. subsidiary, owns 100% interest in a refinery at Milford Haven, Pembrokeshire, Wales. The refinery is located on a 938 acre site owned by the Company; 430 acres are used by the refinery and the remainder is rented for agricultural use. The Milford Haven refinery was shut down for a plant-wide turnaround in early 2010. During the downtime, the Company completed an expansion project that increased the plant s crude oil throughput capacity from 108,000 barrels per day to 135,000 barrels per day. During 2013, the Milford Haven plant processed an average of 122,930 barrels of crude oil per day.

Refinery capacities at the Milford Haven, Wales facility at December 31, 2013 were as follows:

Crude capacity barrels per stream day	135,000
Process capacity barrels per stream day	
Vacuum distillation	55,000
Catalytic cracking fresh feed	37,750
Naphtha hydrotreating/reforming	21,100
Distillate hydrotreating	77,700
Isomerization	15,800
Production capacity barrels per stream day	
Alkylation	6,300
Crude oil and product storage capacity barrels	8,832,200

At the end of 2013, Murco distributed refined products in the United Kingdom from the wholly-owned Milford Haven refinery, three wholly owned terminals supplied by rail, six terminals owned by others where products are received in exchange for deliveries from the Company s terminals and eight terminals owned by others where products are purchased for delivery. At December 31, 2013, there were 229 Company stations, all of which were branded MURCO. The Company owns the freehold on 149 of the sites and leases the remainder. The Company also supplied 227 MURCO branded dealer stations at year-end 2013.

At December 31, 2013, MURCO owned approximately 8.3% of the refining capacity in the United Kingdom. MURCO s retail fuel sales represented 2.4% of the total U.K. market share in 2013.

A statistical summary of key U.K. operating and financial indicators for each of the seven years ended December 31, 2013 are reported on page 6 of the 2013 Annual Report.

Environmental

Murphy s businesses are subject to various U.S. federal, state and local environmental, health and safety laws and regulations, and are also subject to similar laws and regulations in other countries in which it operates. These regulatory requirements continue to change and increase in number and complexity, and the requirements govern the manner in which the company conducts its operations and the products it sells. The Company anticipates more environmental regulations in the future in the countries where it has operations.

Further information on environmental matters and their impact on Murphy are contained in Management s Discussion and Analysis of Financial Condition and Results of Operations on pages 42 through 46.

Web site Access to SEC Reports

Murphy Oil s internet Web site address is http://www.murphyoilcorp.com. Information contained on the Company s Web site is not part of this report on Form 10-K.

The Company s Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on Murphy s Web site, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. You may also access these reports at the SEC s Web site at *http://www.sec.gov.*

Item 1A. RISK FACTORS

Murphy Oil s businesses operate in highly competitive environments, which could adversely affect it in many ways, including its profitability, its ability to grow, and its ability to manage its businesses.

Murphy operates in the oil and gas industry and experiences intense competition from other oil and gas companies, which include state-owned foreign oil companies, major integrated oil companies, independent producers of oil and natural gas and independent refining and marketing companies. Virtually all of the state-owned and major integrated oil companies and many of the independent producers and refiners that compete with the Company have substantially greater resources than Murphy. In addition, the oil industry as a whole competes with other industries in supplying energy requirements around the world. Murphy competes, among other things, for valuable acreage positions, exploration licenses, drilling equipment and human resources.

If Murphy cannot replace its oil and natural gas reserves, it may not be able to sustain or grow its business.

Murphy continually depletes its oil and natural gas reserves as production occurs. In order to sustain and grow its business, the Company must successfully replace the crude oil and natural gas it produces with additional reserves. Therefore, it must create and maintain a portfolio of good prospects for future reserves additions and production by obtaining rights to explore for, develop and produce hydrocarbons in promising areas. In addition, it must find, develop and produce and/or purchase reserves at a competitive cost structure to be successful in the long-term. Murphy s ability to operate profitably in the exploration and production segments of its business, therefore, is dependent on its ability to find, develop and produce and/or purchase oil and natural gas reserves at costs that are less than the realized sales price for these products and at costs competitive with competing companies in the industry.

Murphy s proved reserves are based on the professional judgment of its engineers and may be subject to revision.

Proved oil and natural gas reserves included in this report on pages F-52 through F-55 have been prepared by qualified Company personnel or qualified independent engineers based on an unweighted average of oil and natural gas prices in effect at the beginning of each month as well as other conditions and information available at the time the estimates were prepared. Estimation of reserves is a subjective process that involves professional judgment by engineers about volumes to be recovered in future periods from underground oil and natural gas reservoirs. Estimates of economically recoverable oil and natural gas reserves and future net cash flows depend upon a number of variable factors and assumptions, and consequently, different engineers could arrive at different estimates of reserves and future net cash flows based on the same available data and using industry accepted engineering practices and scientific methods. Under existing SEC rules, reported proved reserves must be reasonably certain of recovery in future periods.

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Murphy s actual future oil and natural gas production may vary substantially from its reported quantity of proved reserves due to a number of factors, including:

Oil and natural gas prices which are materially different than prices used to compute proved reserves

Operating and/or capital costs which are materially different than those assumed to compute proved reserves

Future reservoir performance which is materially different from models used to compute proved reserves, and

Governmental regulations or actions which materially change operations of a field.

The Company s proved undeveloped reserves represent significant portions of total proved reserves. As of December 31, 2013, approximately 39% of the Company s proved oil reserves and 32% of proved natural gas reserves are undeveloped. The ability of the Company to reclassify these undeveloped proved reserves to the proved developed classification is generally dependent on the successful completion of one or more operations, which might include further development drilling, construction of facilities or pipelines, and well workovers.

The discounted future net revenues from our proved reserves as reported on pages F-59 and F-60 should not be considered as the market value of the reserves attributable to our properties. As required by generally accepted accounting principles, the estimated discounted future net revenues from our proved reserves are based on an unweighted average of the oil and natural gas prices in effect at the beginning of each month during the year. Actual future prices and costs may be materially higher or lower than those used in the reserves computations. In addition, the 10 percent discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under generally accepted accounting principles is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the crude oil and natural gas business in general.

Volatility in the global prices of oil, natural gas and petroleum products significantly affects the Company s operating results.

Among the most significant variables affecting the Company s results of operations are the sales prices for crude oil and natural gas that it produces. West Texas Intermediate (WTI) crude oil prices averaged about $98 per barrel in 2013, compared to $94 per barrel in 2012 and $95 per barrel in 2011. Although WTI average prices in 2013 were not significantly different than the two previous years, prices can be quite volatile as demonstrated by the range of high and low prices during 2013 of about $110 per barrel and $87 per barrel, respectively. The average NYMEX natural gas sales prices were $3.73 per thousand cubic feet (MCF) in 2013, up from $2.83 per MCF in 2012, but lower than the $4.03 per MCF average in 2011. This relatively low price for natural gas hurt the Company s profits in North America during the three years ended December 31, 2013. As demonstrated in 2011 through 2013, the sales prices for oil and natural gas can be significantly different in U.S. markets compared to markets in foreign locations. Certain of the Company s crude oil production is heavy and more sour than WTI quality crude; therefore, this crude oil usually sells at a discount to WTI and other light and sweet crude oils. In addition, the sales prices for heavy and sour crude oils do not always move in relation to price changes for WTI and lighter/sweeter crude oils. Certain crude oils produced by the Company, including certain U.S. and Canadian crude oils and all crude oil produced in Malaysia, generally price off other oil indices than WTI, and these indices are influenced by different supply and demand forces than those that affect the U.S. WTI prices. The most common crude oil indices used to price the Company s crude include Louisiana Light Sweet (LLS), Brent and Malaysian crude oil indices. Certain natural gas production offshore Sarawak have been sold in recent years at a premium to average North American natural gas prices due to pricing structures built into the sales contracts. Associated natural gas produced at fields in Block K offshore Sabah are sold at heavily discounted prices compared to North American gas prices as stipulated in the sales contract. The Company cannot predict how changes in the sales prices of oil and natural gas will affect its results of operations in future periods. The Company often seeks to hedge a portion of its exposure to the effects of changing prices of crude oil and natural gas by purchasing forwards, swaps and other forms of derivative contracts.

Exploration drilling results can significantly affect the Company s operating results.

The Company generally drills numerous wildcat wells each year which subjects its exploration and production operating results to significant exposure to dry holes expense, which have adverse effects on, and create volatility for, the Company s net income. In 2013, significant wildcat wells were primarily drilled offshore Cameroon, Brunei, Australia and in the Gulf of Mexico. The Company s 2014 planned exploratory drilling program includes wells offshore in the Gulf of Mexico, Cameroon, Brunei, Australia, Vietnam and Indonesia.

Potential federal or state regulations regarding hydraulic fracturing could increase our costs and/or restrict operating methods, which could adversely affect our production levels.

The Company uses a technique known as hydraulic fracturing whereby water, sand and other chemicals are injected into deep oil and gas bearing reservoirs. This process creates fractures in the rock formation within the reservoir which enables oil and natural gas to migrate to the wellbore. The Company primarily uses this technique in the Eagle Ford Shale in South Texas and in Western Canada. This practice is generally regulated by the states, but at times the U.S. has proposed regulation under the Safe Drinking Water Act. In June 2011, the State of Texas adopted a law requiring public disclosure of certain information regarding the components used in the hydraulic fracturing process. The Provinces of British Columbia and Alberta have also issued regulations related to hydraulic fracturing activities under their jurisdictions. It is possible that the states, the U.S., Canadian provinces or certain municipalities may adopt further laws or regulations which could render the process less effective or drive up its costs. If any such action is taken in the future, our production levels could be adversely affected or our costs of drilling and completion could be increased.

Capital financing may not always be available to fund Murphy s activities.

Murphy usually must spend and risk a significant amount of capital to find and develop reserves before revenue is generated from production. Although most capital needs are funded from operating cash flow, the timing of cash flows from operations and capital funding needs may not always coincide, and the levels of cash flow generated by operations may not fully cover capital funding requirements. Therefore, the Company maintains financing arrangements with lending institutions to meet certain funding needs. The Company must periodically renew these financing arrangements based on foreseeable financing needs or as they expire. The Company s primary bank financing facility was renewed in 2011. In 2013, the Company increased the capacity of its financing facility from $1.5 billion to $2.0 billion and extended the facility by one year such that it now expires in June 2017. Although not considered likely, there is the possibility that financing arrangements may not always be available at sufficient levels required to fund the Company s activities in future periods. The Company has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities through October 2015. Although not considered likely, the Company may not be able in the future to sell notes at reasonable rates in the marketplace.

Murphy has limited or virtually no control over several factors that could adversely affect the Company.

The ability of the Company to successfully manage development and operating costs is important because virtually all of the products it sells are energy commodities such as crude oil, natural gas and refined products, for which the Company has little or no influence on the sales prices or regional and worldwide consumer demand for these products. Economic slowdowns, such as those experienced in 2008 and 2009, had a detrimental effect on the worldwide demand for these energy commodities, which effectively led to reduced prices for oil, natural gas and refined products for a period of time. Lower prices for crude oil and natural gas inevitably lead to lower earnings for the Company. The Company also often experiences pressure on its operating and capital expenditures in periods of strong crude oil and natural gas prices because an increase in exploration and production activities due to high oil and gas sales prices generally leads to higher demand for, and consequently higher costs for, goods and services in the oil and gas industry.

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Many of the Company s major oil and natural gas producing properties are operated by others. Therefore, Murphy does not fully control all activities at certain of its significant revenue generating properties. During 2013, approximately 16% of the Company s total production was at fields operated by others, while at December 31, 2013, approximately 27% of the Company s total proved reserves were at fields operated by others.

Murphy s operations and earnings have been and will continue to be affected by worldwide political developments.

Many governments, including those that are members of the Organization of Petroleum Exporting Countries (OPEC), unilaterally intervene at times in the orderly market of crude oil and natural gas produced in their countries through such actions as setting prices, determining rates of production, and controlling who may buy and sell the production. As of December 31, 2013, approximately 28% of proved reserves, as defined by the U.S. Securities and Exchange Commission, were located in countries other than the U.S. and Canada. Certain of the reserves held outside these two countries could be considered to have more political risk. In addition, prices and availability of crude oil, natural gas and refined products could be influenced by political unrest and by various governmental policies to restrict or increase petroleum usage and supply. Other governmental actions that could affect Murphy s operations and earnings include expropriation, tax changes, royalty increases, redefinition of international boundaries, preferential and discriminatory awarding of oil and gas leases, restrictions on drilling and/or production, restraints and controls on imports and exports, safety, and relationships between employers and employees. Governments could also initiate regulations concerning matters such as currency fluctuations, protection and remediation of the environment, and concerns over the possibility of global warming being affected by human activity including the production and use of hydrocarbon energy. Additionally, because of the numerous countries in which the Company operates, certain other risks exist, including the application of the U.S. Foreign Corrupt Practices Act, the Canada Corruption of Foreign Officials Act, the Malaysia Anti-Corruption Commission Act, the U.K. Bribery Act, and similar anti-corruption compliance statutes. Because these and other factors too numerous to list are subject to changes caused by governmental and political considerations and are often made in response to changing internal and worldwide economic conditions and to actions of other governments or specific events, it is not practical to attempt to predict the effects of such factors on Murphy s future operations and earnings.

Murphy s business is subject to operational hazards and risks normally associated with the exploration for and production of oil and natural gas and the refining and marketing of crude oil and petroleum products.

The Company operates in urban and remote, and often inhospitable, areas around the world. The occurrence of an event, including but not limited to acts of nature such as hurricanes, floods, earthquakes and other forms of severe weather, and mechanical equipment failures, industrial accidents, fires, explosions, acts of war, civil unrest, piracy and acts of terrorism could result in the loss of hydrocarbons and associated revenues, environmental pollution or contamination, and personal injury, including death, for which the Company could be deemed to be liable, and which could subject the Company to substantial fines and/or claims for punitive damages.

In April 2010, a drilling accident and subsequent oil spill occurred in the Gulf of Mexico at the Macondo well owned by other companies. Impacts of the accident and oil spill include additional regulations covering offshore drilling operations, a general lengthening in the time required for regulatory permitting, and higher costs for future drilling operations and offshore insurance. Additional regulations, possible further permitting delays and other restrictions associated with drilling and similar operations in the Gulf of Mexico could have an adverse affect on the Company s future costs of oil and natural gas produced in this area.

The location of many of Murphy s key assets causes the Company to be vulnerable to severe weather, including hurricanes and tropical storms. A number of significant oil and natural gas fields lie in offshore waters around the world. Probably the most vulnerable of the Company s offshore fields are in the U.S. Gulf of Mexico, where severe hurricanes and tropical storms have often led to shutdowns and damages. The U.S. hurricane season runs from June through November. Although the Company maintains insurance for such risks as described elsewhere in this Form 10-K report, due to policy deductibles and possible coverage limits, weather-related risks are not fully insured.

Murphy may be unable to complete its announced reorganization plan.

The Company has announced the intended sale of its U.K. downstream business. Factors that could cause this event not to occur include, but are not limited to, a failure to obtain necessary regulatory approvals, a deterioration in the business or prospects of Murphy or its subsidiaries, adverse developments in Murphy or its subsidiaries markets, adverse developments in the U.S. or global capital markets, credit markets or economies generally or a failure to execute a sale of the U.K. downstream operations on acceptable terms.

With the separation of its U.S. downstream operations, and the intended sale of its U.K. downstream business, Murphy will have fewer cash flow generating assets to service its debt.

With the separation of the Company s U.S. downstream assets, Murphy no longer has the cash flow generated from these assets to make interest and principal payments on its debt. Similarly, if the proposed sale of Murphy s U.K. downstream operations is completed, the Company will no longer have ongoing cash flows generated from these assets to service its debt. If Murphy s remaining exploration and production business is not successful as a stand-alone company, the Company may not have sufficient cash flow needed to make interest payments on outstanding notes, repay the notes at maturity or refinance the notes on acceptable terms, if at all.

Murphy s insurance may not be adequate to offset costs associated with certain events and there can be no assurance that insurance coverage will continue to be available in the future on terms that justify its purchase.

Murphy maintains insurance against certain, but not all, hazards that could arise from its operations. The Company maintains liability insurance sufficient to cover its share of gross insured claim costs up to approximately $700 million per occurrence and in the annual aggregate. These policies have up to $10 million in deductibles. Generally, this insurance covers various types of third party claims related to personal injury, death and property damage, including claims arising from sudden and accidental pollution events. The Company also maintains insurance coverage with an additional limit of $300 million per occurrence ($750 million for Gulf of Mexico operations not related to a named windstorm), all or part of which could be applicable to certain sudden and accidental pollution events. The occurrence of an event that is not insured or not fully insured could have a material adverse effect on the Company s financial condition and results of operations in the future.

Lawsuits against Murphy and its subsidiaries could adversely affect its operating results.

The Company is involved in numerous lawsuits seeking cash settlements for alleged personal injuries, property damages and other business-related matters. Certain of these lawsuits will take many years to resolve through court proceedings or negotiated settlements. None of these lawsuits are considered individually material or aggregate to a material amount in the opinion of management.

The Company is exposed to credit risks associated with sales of certain of its products to third parties.

Although Murphy limits its credit risk by selling its products to numerous entities worldwide, it still, at times, carries substantial credit risk from its customers. For certain oil and gas properties operated by the Company, other companies which own partial interests may not be able to meet their financial obligation to pay for their share of capital and operating costs as they come due. The inability of a purchaser of the Company s oil or natural gas or a partner of the Company to meet their respective payment obligations to the Company could have an adverse effect on Murphy s future earnings and cash flows.

Murphy s operations could be adversely affected by changes in foreign currency conversion rates.

The Company s worldwide operational scope exposes it to risks associated with foreign currencies. Most of the Company s business is transacted in U.S. dollars, therefore, the Company and most of its subsidiaries are U.S. dollar functional entities for accounting purposes. However, the Canadian dollar is the functional currency for all

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Canadian operations and the British pound is the functional currency for U.K. refining and marketing operations. In certain countries, such as Malaysia, the United Kingdom and Canada, significant levels of transactions occur in currencies other than the functional currency. In Malaysia, such transactions include tax payments, while in the U.K., virtually all crude oil feedstock purchases and certain bulk product sales are priced in U.S. dollars, and in Canada, certain crude oil sales are priced in U.S. dollars. This exposure to currencies other than the functional currency can lead to significant impacts on consolidated financial results. In Malaysia, known future tax payments based in local currency are often hedged with contracts that match tax payment amounts and dates to lock in the exchange rate between the U.S. dollar and Malaysian ringgit. Exposures associated with deferred income tax liability balances in Malaysia are not hedged. A strengthening of the Malaysian ringgit against the U.S. dollar would be expected to lead to currency losses in consolidated income; gains would be expected in income if the ringgit weakens versus the dollar. Foreign exchange exposures between the U.S. dollar and the British pound are not hedged due to the frequency and volatility of U.S. dollar transactions in the U.K. downstream business. The Company would generally expect to incur currency losses when the U.S. dollar strengthens against the British pound and would conversely expect currency gains when the U.S. dollar weakens against the pound. In Canada, currency risk is often managed by selling forward U.S. dollars to match the collection dates for crude oil sold in that currency. See Note K in the consolidated financial statements for additional information on derivative contracts.

The costs and funding requirements related to the Company s retirement plans are affected by several factors.

A number of actuarial assumptions impact funding requirements for the Company s retirement plans. The most significant of these assumptions include return on assets, long-term interest rates and mortality. If the actual results for the plans vary significantly from the actuarial assumptions used, or if laws regulating such retirement plans are changed, Murphy could be required to make more significant funding payments to one or more of its retirement plans in the future and/or it could be required to record a larger liability for future obligations in its Consolidated Balance Sheet.

Item 1B. UNRESOLVED STAFF COMMENTS

The Company had no unresolved comments from the staff of the U.S. Securities and Exchange Commission as of December 31, 2013.

Item 2. PROPERTIES

Descriptions of the Company s oil and natural gas properties and refining and marketing operations are included in Item 1 of this Form 10-K report beginning on page 1. Information required by the Securities Exchange Act Industry Guide No. 2 can be found in the Supplemental Oil and Gas Information section of this Annual Report on Form 10-K on pages F-50 to F-60 and in Note D Property, Plant and Equipment beginning on page F-18.

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Executive Officers of the Registrant

Present corporate office, length of service in office and age at February 1, 2014 of each of the Company s executive officers are reported in the following listing. Executive officers are elected annually but may be removed from office at any time by the Board of Directors.

Roger W. Jenkins Age 52; Chief Executive Officer since August 2013. Mr. Jenkins served as Chief Operating Officer from June 2012 to August 2013. Mr. Jenkins was Executive Vice President Exploration and Production from August 2009 through August 2013 and has served as President of the Company s exploration and production subsidiary since January 2009. He was Senior Vice President, North America for this subsidiary from September 2007 to December 2008.

Kevin G. Fitzgerald Age 58; Executive Vice President and Chief Financial Officer since December 2011. Mr. Fitzgerald was Senior Vice President and CFO from January 2007 to November 2011. He served as Treasurer from July 2001 through December 2006.

Walter K. Compton Age 51; Executive Vice President and General Counsel since February 2014. Mr. Compton was Senior Vice President and General Counsel from March 2011 to February 2014. He was Vice President, Law from February 2009 to February 2011 and was Manager, Law from November 1996 to January 2009.

Thomas McKinlay Age 50; Executive Vice President, U.K. Downstream since January 2013. Mr. McKinlay was Executive Vice President, Worldwide Downstream from January 2011 to January 2013 and Vice President, U.S. Manufacturing from August 2009 to January 2011. Mr. McKinlay was President of the Company s U.S. refining and marketing subsidiary from January 2011 to January 2013, and was Vice President, Supply and Transportation of this subsidiary from April 2009 to January 2011. From August 2008 to March 2009, Mr. McKinlay was General Manager, Supply and Transportation of this U.S. subsidiary, and from January 2007 to August 2008 was Supply Director for the Company s U.K. refining and marketing subsidiary.

Bill H. Stobaugh Age 62; Executive Vice President since February 2012. Mr. Stobaugh was Senior Vice President from February 2005 to January 2012.

John W. Eckart Age 55; Senior Vice President and Controller since December 2011. Mr. Eckart was Vice President and Controller from January 2007 to November 2011, and has served as Controller since March 2000.

Kelli M. Hammock Age 42; Senior Vice President, Administration since February 2014. Ms. Hammock was Vice President, Administration from December 2009 to February 2014 and was General Manager, Administration from June 2006 to November 2009.

Tim F. Butler Age 51; Vice President, Tax since August 2013. Mr. Butler was General Manager, Worldwide Taxation from August 2007 to August 2013.

John W. Dumas Age 59; Vice President, Corporate Insurance since February 2014. Mr. Dumas was Director, Corporate Insurance for the Company from 2005 to 2014.

Barry F.R. Jeffery Age 55; Vice President, Investor Relations since August 2013. Mr. Jeffery was Director, Investor Relations from September 2010 to August 2013. Mr. Jeffery served as General Manager, Business Development for the Company s former U.S. downstream subsidiary from November 2009 to August 2010 and was Manager, Crude Supply for this subsidiary from February 2007 to November 2009.

Allan J. Misner Age 47; Vice President, Internal Audit since February 2014. Mr. Misner served as Director, Internal Audit from 2007 to 2014.

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K. Todd Montgomery   Age 49; Vice President, Corporate Planning & Services since February 2014. Mr. Montgomery joined the Company in 2014 following 25 years of experience with another major independent oil company. With his prior employer, Mr. Montgomery s duties included responsibilities covering global production, reservoir engineering, strategic planning and development.

E. Ted Botner   Age 48; Secretary since August 2013. Mr. Botner has served as Manager, Law since August 2013. He was Senior Attorney from February 2010 to August 2013 and was General Manager, Malaysia for the Company s exploration and production subsidiary from July 2007 to January 2010.

John B. Gardner   Age 45; Treasurer since August 2013. Mr. Gardner was Assistant Treasurer from January 2012 to August 2013. He was Director of Planning and Special Projects for the Company s U.K. downstream subsidiary from March 2010 to December 2011, and was Controller USA for the Company s U.S. exploration and production subsidiary from January 2008 to February 2010.

Item 3. LEGAL PROCEEDINGS

Murphy and its subsidiaries are engaged in a number of other legal proceedings, all of which Murphy considers routine and incidental to its business. Based on information currently available to the Company, the ultimate resolution of matters referred to in this item is not expected to have a material adverse effect on the Company s net income, financial condition or liquidity in a future period.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

Item 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The Company s Common Stock is traded on the New York Stock Exchange using MUR as the trading symbol. There were 2,598 stockholders of record as of December 31, 2013. Information as to high and low market prices per share and dividends per share by quarter for 2013 and 2012 are reported on page F-61 of this Form 10-K report.

Murphy Oil Corporation

Issuer Purchases of Equity Securities

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[1,2]
October 1, 2013 to October 31, 2013		$		$ 500,000,000
November 1, 2013 to November 30, 2013	3,678,591	67.96[3]	3,678,591	250,000,000
December 1, 2013 to December 31, 2013				250,000,000
Total October 1, 2013 to December 31, 2013	**3,678,591**	**67.96**	**3,678,591**	**250,000,000**

1 On October 16, 2012, the Company announced that its Board of Directors had authorized a buyback of up to $1.0 billion of the Company s Common stock. The buyback program has been extended to April 2014 by the Company s Board. On November 11, 2013, the Company announced that it had entered into a variable term, capped accelerated share repurchase transaction (ASR) with a major financial institution to repurchase an aggregate of $250 million of the Company s Common stock. The total aggregate number of shares repurchased pursuant to this ASR was determined by reference to the Rule 10b-18 volume-weighted price of the Company s Common stock, less a fixed discount, over the term of the ASR, subject to a minimum number of shares. The ASR was completed in January 2014, and the Company received an additional 284,743 shares upon completion of the ASR program.

2 Through December 31, 2013, the Company has expended $750.0 million of the $1.0 billion approved program. With these purchases, the Company has acquired 12,007,712 shares under the approved stock buyback program, including additional shares received in January 2014 upon completion of the ASR that was open at December 31, 2013.

3 The average price disclosed represents the maximum price per share for the Company s Common stock to be acquired under the ASR. The additional shares received upon completion of the ASR in January 2014 reduced the average price paid for the shares acquired to $63.08 per share. See Note U of the Company s consolidated financial statements regarding discussion of other 2014 share repurchase activities.

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SHAREHOLDER RETURN PERFORMANCE PRESENTATION

The following graph presents a comparison of cumulative five-year shareholder returns (including the reinvestment of dividends) as if a $100 investment was made on December 31, 2008 for the Company, the Standard & Poor s 500 Stock Index (S&P 500 Index) and the NYSE ARCA Oil Index. This performance information is furnished by the Company and is not considered as filed with this Form 10-K and it is not incorporated into any document that incorporates this Form 10-K by reference.

	2008	2009	2010	2011	2012	2013
Murphy Oil Corporation	100	124	174	133	152	195
S&P 500 Index	100	126	146	149	172	223
NYSE ARCA Oil Index	100	113	132	138	143	175

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Item 6. SELECTED FINANCIAL DATA

(Thousands of dollars except per share data)	**2013**	2012	2011	2010	2009
Results of Operations for the Year					
Sales and other operating revenues	**$ 5,312,686**	4,608,563	4,222,520	3,556,461	2,982,769
Net cash provided by continuing operations	**3,210,695**	2,911,380	1,688,884	2,491,017	1,583,687
Income from continuing operations	**888,137**	806,494	539,198	618,493	656,187
Net income	**1,123,473**	970,876	872,702	798,081	837,621
Per Common share diluted					
Income from continuing operations	**$ 4.69**	4.14	2.77	3.20	3.41
Net income	**5.94**	4.99	4.49	4.13	4.35
Cash dividends per Common share	**1.25**	3.675[1]	1.10	1.05	1.00
Percentage return on[2]					
Average stockholders equity	**12.5**	10.5	9.9	10.3	12.5
Average borrowed and invested capital	**10.3**	9.6	9.2	9.4	10.9
Average total assets	**6.3**	6.2	5.7	5.9	7.0
Capital Expenditures for the Year[3]					
Continuing operations					
Exploration and production	**$ 3,943,956[4]**	4,185,028	2,748,008	2,023,309	1,790,163
Corporate and other	**22,014**	8,077	5,218	5,899	22,967
	3,965,970	4,193,105	2,753,226	2,029,208	1,813,130
Discontinued operations	**154,622**	190,881	190,586	418,932	394,139
	$ 4,120,592	4,383,986	2,943,812	2,448,140	2,207,269
Financial Condition at December 31					
Current ratio	**1.09**	1.21	1.22	1.21	1.55
Working capital	**$ 284,612**	699,502	622,743	619,783	1,194,087
Net property, plant and equipment	**13,481,055**	13,011,606	10,475,149	10,367,847	9,065,088
Total assets	**17,509,484**	17,522,643	14,138,138	14,233,243	12,756,359
Long-term debt	**2,936,563**	2,245,201	249,553	939,350	1,353,183
Stockholders equity	**8,595,730**	8,942,035	8,778,397	8,199,550	7,346,026
Per share	**46.87**	46.91	45.31	42.52	38.44
Long-term debt percent of capital employed[2]	**25.5**	20.1	2.8	10.3	15.6

1 Includes special dividend of $2.50 per share paid on December 3, 2012.

2 Company management uses certain measures for assessing its business results, including percentage return on average stockholders equity, percentage return on average borrowed and invested capital, and percentage return on average total assets. Additionally, the Company measures its long-term debt leverage using long-term debt as a percentage of total capital employed (long-term debt plus stockholders equity). We consistently disclose these financial measures because we believe our shareholders and other interested parties find such measures helpful in understanding trends and results of the Company and as a comparison of Murphy Oil to other companies in the oil and gas and other industries.

Specifically, these measures were computed as follows for each year:

Percentage return on average stockholders equity net income for the year (as per the consolidated statement of income) divided by a 12-month average for January to December of total stockholders equity.

Percentage return on average borrowed and invested capital the sum of net income for the year (as per the consolidated statement of income) plus after-tax interest expense for the year divided by a 12-month average for January to December of the sum of total long-term debt plus total stockholders equity.

Percentage return on average total assets net income for the year (as per the consolidated statement of income) divided by a 12-month average for January to December of total consolidated assets.

Long-term debt percent of capital employed total long-term debt at the balance sheet date (as per the consolidated balance sheet) divided by the sum of total long-term debt plus total stockholders equity at that date (as per the consolidated balance sheet).

These financial measures may be calculated differently than similarly titled measures that may be presented by other companies.

[3] Capital expenditures include accruals for incurred but unpaid capital activities, while property additions and dry holes in the Statements of Cash Flows are cash-based capital expenditures and do not include capital accruals and geological, geophysical and certain other exploration expenses that are not eligible for capitalization under oil and gas accounting rules.

[4] Excludes property addition of $358.0 million associated with non-cash capital lease at the Kakap field.

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

RESULTS OF OPERATIONS

Overview

Murphy Oil Corporation is a worldwide oil and gas exploration and production company. Murphy owns refining and marketing operations in the United Kingdom, but has announced its intention to sell these U.K. assets. A more detailed description of the Company s significant assets can be found in Item 1 of this Form 10-K report.

Significant Company operating and financial highlights during 2013 were as follows:

- Completed the separation of Murphy USA Inc. on August 30, 2013 creating a significant value enhancement for shareholders.
- Continued to progress the sale of U.K. refining and marketing operations, with an expected completion date during 2014.
- Generated the second highest net income in the Company s history.
- Produced a Company record of more than 205,700 barrels of oil equivalent per day.
- Ended 2013 with a Company record level of proved reserves, and had organic replacement of proved reserves equal to 243% of production on a barrel of oil equivalent basis during the year.
- Repurchased almost eight million Common shares at a cost of $500 million.
- Made three natural gas discoveries in Block CA-2 in Brunei.

The year of 2013 was a period of significant transition for Murphy Oil Corporation. The Company had previously announced its intention to fully divest its refining and marketing businesses to become an independent oil and gas exploration and production company. Steps taken in 2013 led to significant progress with meeting this desire to focus only on upstream operations.

On August 30, 2013, the Company completed the separation of its former U.S. retail marketing business by distributing all common shares of this business to Murphy Oil s shareholders. This separation, commonly known as a spin-off , distributed one share of the retail marketing company, now known as Murphy USA Inc., for every four shares of Murphy Oil Corporation common stock owned on the record date of August 21, 2013. Murphy USA Inc. shares trade on the New York Stock Exchange under the ticker symbol MUSA . Additionally, the Company progressed the sale of its U.K. refining and marketing operations. Achievement of the U.K. sale, expected to occur during 2014, will complete the Company s transition to an independent oil and gas company. Both the U.S. and U.K. downstream businesses are now reported as discontinued operations within the Company s consolidated financial statements. Additionally, the Company includes U.K. oil and gas operations, which were sold in a series of transactions in the first half of 2013, as discontinued operations.

Murphy generates revenue by selling oil and natural gas production to customers in the United States, Canada and Malaysia. The Company s revenue is highly affected by the prices of oil and natural gas. In order to make a profit and generate cash in its exploration and production business, revenue generated from the sales of oil and natural gas produced must exceed the combined costs of producing these products, depreciation of capital expenditures, and expenses related to exploration, administration, and for capital borrowed from lending institutions and note holders.

Changes in the price of crude oil and natural gas have a significant impact on the profitability of the Company, especially the price of crude oil as oil represented approximately 66% of total hydrocarbons produced on an energy equivalent basis (one barrel of crude oil equals six thousand cubic feet of natural gas) by the Company s upstream operations in 2013. In 2014, the Company s ratio of hydrocarbon production represented by oil is expected to increase to more than 70% due to a combination of growing oil production and declining North American natural gas production. When oil-price linked natural gas is combined with oil production, the

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Company s 2014 total expected production is more than 80% linked to the price of oil. If the prices for crude oil and natural gas should weaken in 2014 or beyond, the Company would expect this to have an unfavorable impact on operating profits for its exploration and production business. As described on page 54, the Company has entered into derivative and forward delivery contracts that will reduce its exposure to changes in certain oil and natural gas prices in 2014 and 2015.

Worldwide oil prices in 2013 were generally comparable to 2012, while the sale prices for natural gas produced in North America was improved compared to the prior year. Among the various indices on which sales prices of the Company s crude oil are marketed, prices were mixed in 2013 versus the prior year. The sales price for a barrel of West Texas Intermediate (WTI) crude oil averaged $98.05 in 2013, $94.15 in 2012 and $95.11 in 2011. The sales price for a barrel of Platts Dated Brent declined to $108.66 per barrel in 2013, following averages of $111.67 per barrel and $111.26 per barrel in 2012 and 2011, respectively. The NYMEX natural gas price per million British Thermal Units (MMBTU) averaged $3.73 in 2013, $2.83 in 2012 and $4.03 in 2011. While the WTI index saw a 4% increase in 2013, Dated Brent fell back by 3% compared to 2012. During 2013 the discount for WTI crude compared to Dated Brent narrowed a bit compared to the two prior years. The WTI to Dated Brent discount was $10.61 per barrel during 2013, compared to $17.52 per barrel in 2012 and $16.15 per barrel in 2011. During 2012 the price of WTI fell slightly compared to 2011, however, certain other benchmark oil prices, including Dated Brent, experienced small increases in 2012 versus the prior year. NYMEX natural gas prices increased 32% in 2013 compared to 2012 generally due to more extreme weather conditions in North America in the later year which created more demand by gas consumers. Natural gas prices fell in 2012 from 2011 levels primarily due to expansion of North American gas supply and a warmer than normal winter season in 2012 in the U.S. and Canada. On an energy equivalent basis, the market continued to discount North American natural gas compared to crude oil in 2013. However, compared to 2012, this natural gas to oil price discount narrowed a bit during 2013. U.S. crude oil prices in early 2014 have been similar to 2013 average prices, while natural gas prices in North America in 2014 have thus far been above the 2013 levels due to cold temperatures across much of the Northern U.S. during the early winter season.

Results of Operations

Murphy Oil s results of operations, with associated diluted earnings per share (EPS), for the last three years are presented in the following table.

	Years Ended December 31		
(Millions of dollars, except EPS)	**2013**	2012	2011
Net income	**$ 1,123.5**	970.9	872.7
Diluted EPS	**5.94**	4.99	4.49
Income from continuing operations	**$ 888.1**	806.5	539.2
Diluted EPS	**4.69**	4.14	2.77
Income from discontinued operations	**$ 235.4**	164.4	333.5
Diluted EPS	**1.25**	0.85	1.72

Murphy Oil s net income in 2013 was 16% higher than 2012, with the improvement attributable to better earnings for exploration and production (E&P or upstream) operations and higher income from discontinued operations. Continuing operations income improved 10% primarily due to growth in oil production in the E&P business, but the Company experienced higher costs for Corporate activities that were not allocated to operating segments during 2013. The improvement in discontinued operations results by 43% was attributable to a gain on sale of U.K. oil and gas assets in 2013 and better profits for U.S. retail marketing operations, but U.K. downstream results was significantly below 2012 levels.

Net income in 2012 increased 11% compared to 2011 primarily due to higher earnings for continuing E&P operations, partially offset by both lower earnings for discontinued operations and higher net costs of corporate activities not allocated to operating segments.

Further explanations of each of these variances are found in more detail in the following sections.

2013 vs. 2012 Net income in 2013 totaled $1,123.5 million ($5.94 per diluted share) compared to net income in 2012 of $970.9 million ($4.99 per diluted share). Income from continuing operations increased from $806.5 million ($4.14 per diluted share) in 2012 to $888.1 million ($4.69 per diluted share) in 2013. The 2013 improvement in income from continuing operations was attributable to higher oil sales volumes, lower impairment expense and higher tax benefits associated with investments in foreign upstream operations which are being exited. These were partially offset by higher extraction and exploration expenses, lower average oil sales prices, and higher costs associated with borrowed funds and company administration. Income from discontinued operations was $235.4 million ($1.25 per diluted share) in 2013, up from $164.4 million ($0.85 per diluted share) in 2012. Income from discontinued operations in both years included results for refining and marketing (R&M or downstream) operations in the U.S. and U.K. and for oil and gas production operations in the U.K. The improvement in discontinued operations in 2013 was attributable to a gain on disposal of all U.K. oil and gas assets during the year, coupled with stronger income contributions from the separated U.S. retail marketing business in 2013. These favorable factors were partially offset by unfavorable results for U.K. R&M operations caused by both significantly weaker operating margins and a $73.0 million charge to writedown the carrying value of these operating assets.

Sales and other operating revenues grew $704.1 million in 2013 compared to the prior year. Sales rose in 2013 primarily due to higher oil sales volumes associated with a 20% increase in oil production volumes. Sales also benefited from higher realized North American natural gas sales prices, which increased $0.61 per thousand cubic feet (MCF) in 2013 compared to the prior year. However, prices for worldwide average realized oil sales and Sarawak, Malaysia natural gas sales fell $1.98 per barrel and $0.84 per MCF, respectively, which had a detrimental effect on sales revenue. Additionally, natural gas sales volumes fell during 2013 due to both well decline in Western Canada caused by voluntary curtailment of drilling operations and lower net gas sales volumes offshore Malaysia caused by lower third party demand and a lower revenue share allocable to the Company for Sarawak gas sold compared to the prior year. Interest and other income was $66.5 million higher in 2013 than in 2012 primarily due to more favorable impacts from transactions denominated in foreign currencies during the most current year. Operating expenses increased $225.4 million in 2013 due to higher overall hydrocarbon production levels and costs related to shutdown of the Azurite field in Republic of the Congo. Exploration expenses in 2013 were $121.3 million more than 2012 due to higher unsuccessful exploratory drilling costs, primarily in the U.S. Gulf of Mexico, Western Canada, Australia and Cameroon, plus higher geophysical data acquisition costs, primarily in Vietnam, Australia, Indonesia, West Africa and the U.S. Lower undeveloped lease amortization in 2013 in the U.S., Canada and Kurdistan partially offset these higher drilling and geophysical costs. Selling and general expense rose $129.6 million in 2013 primarily due to higher compensation expense and costs related to separation of the U.S. retail marketing business. Depreciation, depletion and amortization expense increased $300.3 million in the current year due to both higher hydrocarbon sales volumes and higher per-unit depreciation rates mostly caused by increasing field development costs for new fields. Impairment of properties declined by $178.4 million in 2013 due to a $200.0 million charge at the Azurite field in the prior year compared to a $21.6 million writedown of certain Western Canada producing properties sold in 2013. Accretion of asset retirement obligations increased by $10.6 million in the current year due to both higher estimated upstream abandonment costs and a higher producing well count, which increased the level of future well abandonment liabilities recorded on a discounted basis. Interest expense rose $70.3 million in 2013 due to higher average borrowing levels in the current year, plus a higher average interest rate caused by a full year of interest applicable on notes payable issued near mid-year 2012. Interest capitalized to development operations in 2013 exceeded the prior year by $13.4 million primarily due to a higher level of oil development projects offshore Malaysia in the current year. Income tax expense increased $23.0 million in 2013 due to higher earnings before taxes partially offset by higher current year U.S. income tax benefits for tax deductions on investments in foreign upstream operations for which the Company is exiting. The consolidated effective tax rate was 39.7% in 2013 compared to 41.0% in 2012, with the lower rate in the later year primarily caused by higher U.S. tax benefits for investments in Republic of the Congo. The tax rate in both 2013 and 2012 were higher than the U.S. federal statutory tax rate of 35.0% due to both foreign tax rates in certain areas that exceeded the U.S.

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federal tax rate and certain exploration and other expenses in foreign taxing jurisdictions for which no income tax benefit is currently being recognized because of the Company s uncertain ability to obtain tax benefits for these costs in 2013 or future years.

2012 vs. 2011 Net income in 2012 was $970.9 million ($4.99 per diluted share) compared to $872.7 million ($4.49 per diluted share) in 2011. Income from continuing operations was $806.5 million ($4.14 per diluted share) in 2012, up from $539.2 million ($2.77 per diluted share) in 2011. Earnings from continuing operations in 2012 increased primarily due to a combination of lower impairment charges, U.S. income tax benefits associated with investments in foreign upstream operations, higher crude oil sales volumes and lower exploration expenses. These were partially offset by lower North American natural gas sales prices and unfavorable effects of foreign exchange compared to the prior year. Net income in 2012 and 2011 included income from discontinued operations of $164.4 million ($0.85 per diluted share) and $333.5 million ($1.72 per diluted share), respectively. Income from discontinued operations in both years included results for downstream operations in the U.S. and U.K. and for oil and gas production operations in the U.K. In 2011 discontinued operations included these operations plus operating profits and a gain on disposal of two U.S. petroleum refineries sold in late 2011. Results for discontinued operations were $169.1 million less in 2012 primarily associated with no repeat of 2011 operating income and net gain on disposal for two U.S. refineries (Meraux, Louisiana and Superior, Wisconsin) and associated marketing assets which were sold in 2011. Additionally, weaker results for U.S. retail marketing operations in 2012 compared to 2011 were somewhat offset by improved results for U.K. refining and marketing operations during 2012.

Sales and other operating revenues grew $386.0 million in 2012 compared to 2011 primarily due to higher crude oil sales volumes for the E&P business. Gain (loss) on sale of assets was $23.1 million less in 2012 than 2011 because the earlier year included a $23.1 million gain on sale of natural gas storage assets in Spain. Interest and other operating income was lower by $22.0 million in 2012 compared to 2011 mostly due to an $18.4 million unfavorable pretax variance from the effects of transactions denominated in foreign currencies, plus interest income in 2011 of $2.7 million associated with a recovery of Federal royalties for certain deepwater Gulf of Mexico fields. Operating expenses were $104.6 million more in 2012 than 2011 due to higher oil and natural gas production costs caused mostly by higher production volumes in the later year. Exploration expenses were $108.4 million lower in 2012 compared to 2011 due to more drilling success in 2012, plus lower geophysical expense in the Gulf of Mexico, Malaysia, Brunei and the Kurdistan region of Iraq compared to 2011. Selling and general expenses were $40.7 million more in 2012 than in 2011 primarily due to higher employee compensation and professional services costs in the later year. Depreciation, depletion and amortization expense rose $288.4 million in 2012 versus 2011 due to higher crude oil and natural gas sales volumes in 2012 and higher E&P per-unit depreciation rates. Impairment of properties was $168.6 million lower in 2012 than in 2011 due to a smaller impairment charge in Republic of the Congo in 2012. Accretion of asset retirement obligations was $4.5 million more in 2012 than 2011 primarily due to higher discounted abandonment liabilities for wells drilled in 2012 in Malaysia, higher estimated abandonment costs for wells in the Gulf of Mexico, and higher future reclamation costs for synthetic oil operations at Syncrude. Redetermination of working interest at the Terra Nova field was a $5.4 million benefit in 2011 due to nonrecurring income achieved upon final settlement of the redetermination process in early 2011. Interest expense in 2012 was $1.7 million less than 2011 primarily due to lower average interest rates paid on borrowed funds in the later year, partially offset by the effects of higher average outstanding debt levels in 2012. The benefit from capitalized interest was $24.0 million higher in 2012 than the prior year due to larger levels of financing costs allocated to ongoing oil development projects in the later year. Income tax expense in 2012 was $67.2 million less than 2011 primarily due to U.S. income tax benefits of $108.3 million recognized in 2012 associated with investments in upstream operations in Republic of the Congo and Suriname. The consolidated effective tax rate was 41.0% in 2012 compared to 53.8% in 2011, with the lower rate in the later year caused by the U.S. tax benefits for Republic of the Congo and Suriname, a lower percentage of earnings in higher tax jurisdictions in 2012, and lower current year exploration and other expenses in foreign jurisdictions where no income tax benefit can presently be recognized due to no assurance that these expenses will be realized in 2012 or future years to reduce taxes owed. The tax rates in both 2012 and 2011 were higher than the U.S. federal statutory tax rate of 35.0% due to foreign tax rates that exceeded the U.S.

federal tax rate in certain areas, and certain exploration and other expenses in foreign taxing jurisdictions for which no income tax benefit is currently being recognized because of the Company s uncertain ability to obtain tax benefits for these costs in 2012 or future years.

Segment Results In the following table, the Company s results of operations for the three years ended December 31, 2013, are presented by segment. More detailed reviews of operating results for the Company s exploration and production and other activities follow the table.

(Millions of dollars)	**2013**	2012	2011
Exploration and production continuing operations			
United States	**$ 435.4**	168.0	152.7
Canada	**180.8**	208.1	328.0
Malaysia	**786.4**	894.2	812.7
Republic of the Congo	**(9.0)**	(241.1)	(385.3)
Other	**(364.8)**	(124.2)	(293.9)
Total exploration and production continuing operations	**1,028.8**	905.0	614.2
Corporate and other	**(140.7)**	(98.5)	(75.0)
Income from continuing operations	**888.1**	806.5	539.2
Income from discontinued operations	**235.4**	164.4	333.5
Net income	**$ 1,123.5**	970.9	872.7

Exploration and Production Earnings from exploration and production (E&P) continuing operations were $1,028.8 million in 2013, $905.0 million in 2012 and $614.2 million in 2011.

E&P income in 2013 was $123.8 million higher than in 2012 primarily due to higher crude oil sales volumes in 2013 and lower impairment charges in the current year. The 2013 period also had higher North American natural gas sales prices and higher U.S. income tax benefits for investments in foreign upstream operations where the Company is exiting. The 2013 E&P results included lower crude oil sales realizations and higher expenses for oil and gas extraction, exploration and administrative activities. Crude oil sales volumes for continuing operations in 2013 were 23% higher than 2012. The most significant increase occurred in the U.S. where ongoing development operations during the year led to larger oil production in the Eagle Ford Shale area of South Texas. Oil sales volumes also increased in the heavy oil area of Canada following an acquisition of properties in this area in late 2012. Sales volumes were higher offshore Eastern Canada due to increased production at the Terra Nova field, which had more downtime for maintenance in 2012. Sales volumes of synthetic crude oil were lower in 2013 due to more downtime for maintenance during the current year. The average realized sales price for crude oil, condensate and gas liquids declined 2% in 2013 to an average of $93.60 per barrel. Natural gas sales volumes for continuing operations decreased 13% in 2013 and the reduction was primarily attributable to lower gas volumes produced during the current year at the Tupper and Tupper West areas in Western Canada. The Company has voluntarily curtailed drilling activities in this area during the last few years due to low North American gas sales prices. Natural gas sales volumes were also lower during 2013 in Malaysia due to reduced customer demand and a lower entitlement percentage allocable to the Company from fields offshore Sarawak. E&P production expenses were $225.4 million higher in 2013 primarily due to more volumes produced in the Eagle Ford Shale and $82.5 million of costs associated with abandonment activities at the Azurite field, offshore Republic of the Congo. Depreciation, depletion and amortization increased $299.2 million due to both higher overall production and a higher per-unit depreciation rate on new production volumes. Exploration expense rose $121.3 million in 2013 due to higher costs for both unsuccessful exploratory drilling and geophysical data acquisitions, but these were partially offset by lower amortization expense for unproved oil and gas leases. The prior year included a $200.0 million impairment charge to reduce the carrying value of the Azurite oil field in Republic of the Congo. This field went off production in October 2013 and field abandonment operations were underway at year-end 2013. Income tax benefits associated with investments in foreign upstream operations where the Company is exiting were $25.2 million higher in 2013 than 2012. These larger tax benefits were primarily related to U.S. tax deductions associated with investments in Republic of the Congo.

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Income for E&P continuing operations in 2012 was $290.8 million more than in 2011. The increase was primarily attributable to lower impairment charges of $168.6 million in Republic of the Congo in 2012, favorable tax benefits of $108.3 million in 2012 for investments in upstream operations in Republic of the Congo and Suriname, plus higher crude oil and natural gas sales volumes and stronger crude oil sales prices in the later year. The Company s average realized sales price for crude oil, condensate and gas liquids in 2012 for continuing operations increased $1.40 per barrel over 2011. The Company s average natural gas sales prices in Sarawak, Malaysia were also higher in 2012 than 2011, but natural gas sales prices in 2012 in North America were significantly below 2011 levels. Crude oil and liquids sales volumes for continuing operations increased 11% in 2012 while natural gas sales volumes rose 7%. The increase in hydrocarbon sales volumes in 2012 led to higher expenses for production and depreciation of $104.5 million and $288.4 million, respectively. The 2012 year had less exploration expenses of $108.5 million compared to 2011, essentially due to lower expenses related to unsuccessful exploratory drilling and geophysical activities. Crude oil sales volumes increased in 2012 in the U.S. primarily due to higher volumes produced in the Eagle Ford Shale area of South Texas. Conventional oil sales volumes in Canada in 2012 were less than 2011 primarily due to lower gross production at the Terra Nova field, where more downtime for maintenance occurred in 2012. Synthetic oil sales volumes at Syncrude increased in 2012 due to higher gross production compared to 2011. Sales volumes for crude oil produced in Malaysia were higher in 2012 primarily due to new wells brought on production at the Kikeh field offshore Sabah. Crude oil sales volumes decreased in 2012 in Republic of the Congo due to field decline and a well failure at the Azurite field. Natural gas sales volumes in 2012 increased compared to the prior year principally due to more wells producing for a longer period in the Tupper area in Western Canada and higher gas volumes produced in the Eagle Ford Shale.

The results of operations for oil and gas producing activities for each of the last three years are shown by major operating areas on pages F-57 and F-58 of this Form 10-K report. Average daily production and sales rates and weighted average sales prices are shown on page 5 of the 2013 Annual Report.

A summary of oil and gas revenues is presented in the following table.

(Millions of dollars)	**2013**	2012	2011
United States Oil and gas liquids	**$ 1,724.7**	976.1	648.8
Natural gas	**72.7**	54.2	71.1
Canada Conventional oil and gas liquids	**507.2**	411.7	505.6
Synthetic oil	**441.0**	463.1	506.6
Natural gas	**198.1**	209.8	280.2
Malaysia Oil and gas liquids	**1,875.0**	1,946.0	1,583.0
Natural gas	**404.0**	481.1	461.3
Republic of the Congo oil	**83.6**	57.6	148.8
Total oil and gas revenues	**$ 5,306.3**	4,599.6	4,205.4

The Company s total crude oil, condensate and natural gas liquids production averaged 135,078 barrels per day in 2013, compared to 112,591 barrels per day in 2012 and 103,160 barrels per day in 2011.

United States oil production increased from 26,090 barrels per day in 2012 to a U.S. Company record of 48,387 barrels per day in 2013 with the 85% volume increase virtually all related to drilling and other development operations in the Eagle Ford Shale area. The Company s Eagle Ford Shale drilling program in South Texas utilized an average of almost eight drilling rigs throughout 2013 and drilling will continue throughout 2014. Production of heavy oil in Western Canada was 9,128 barrels per day in 2013, up from 7,241 barrels per day in 2012, primarily due to volumes in the current year at properties acquired near the end of 2012. Oil production offshore Canada rose from 6,986 barrels per day in 2012 to 9,099 barrels per day in 2013 primarily due to less downtime in the current year at the Terra Nova field. Synthetic oil operations at Syncrude had net production of 12,886 barrels per day in 2013, down from 13,830 barrels per day in 2012, with the decrease caused by more facility downtime for maintenance in the current year. Oil production in Malaysia increased from 52,663 barrels per day in 2012 to 53,766 barrels per day in 2013, primarily due to start-up of four new oil fields offshore Sarawak in the second half of 2013. Additionally, oil volumes benefited from the early production system at the Kakap-Gumusut field being operational for all of 2013 following a late 2012 start-up. The full Kakap-Gumusut field production system is expected to come onstream in 2014. Oil production at the Kikeh field decreased in 2013 primarily due to well decline. Oil production in Republic of the Congo was lower in 2013 due to continued well decline that led to the field being shut down in October 2013. The Company sold all of its U.K. oil and gas properties through a series of transactions during the first half of the year, and U.K. oil production therefore declined in 2013. All U.K. oil and gas production volumes have been reported as discontinued operations.

United States crude oil production averaged 26,090 barrels per day in 2012, a 52% increase from 17,148 barrels per day in 2011. The U.S. increase was primarily attributable to development drilling in the Eagle Ford Shale area. Heavy oil production in Western Canada of 7,241 barrels per day in 2012 was about flat with 2011. Crude oil production offshore Canada fell from 9,204 barrels per day in 2011 to 6,986 barrels per day in 2012 essentially due to more downtime for maintenance at the Terra Nova field and well decline at the Hibernia field. Synthetic oil production of 13,830 barrels per day in 2012 slightly exceeded 2011 volumes of 13,498 per day. Crude oil and liquids production in Malaysia averaged 52,663 barrels per day in 2012, up from 48,551 barrels per day in 2011, with the increase mainly due to additional wells brought on production at the Kikeh field. Oil production in Republic of the Congo fell to 2,078 barrels per day in 2012 after averaging 4,989 barrels per day in 2011, with the reduction due to a well that went off production during 2012 and normal decline at other wells in the field. Crude oil production from discontinued U.K. operations was 3,458 barrels per day in 2012 compared to 2,423 barrels per day in 2011. The U.K. increase in 2012 was primarily at Schiehallion, where better overall performance more than offset lower volumes produced at the Mungo/Monan field.

Worldwide sales of natural gas were 423.8 million cubic feet (MMCF) per day in 2013, after averaging a Company record 490.1 MMCF per day in 2012 and 457.4 MMCF per day in 2011.

Natural gas sales volumes in the U.S. averaged 53.2 MMCF per day in 2013, slightly above the 53.0 MMCF per day in 2012 as higher production in the Eagle Ford Shale was essentially offset by declines in the Gulf of Mexico and other onshore operations. Natural gas volumes in Canada fell from 217.0 MMCF per day in 2012 to 175.4 MMCF per day in 2013 primarily due to well decline at the Tupper and Tupper West areas in Western Canada. The Company has voluntarily curtailed drilling activities in this dry gas basin due to historically low North American natural gas sales prices. Natural gas sales volume offshore Sarawak, Malaysia declined to 164.7 MMCF per day in 2013 compared to 174.3 MMCF per day in 2012. This reduction was caused by a combination of lower third party demand and a lower entitlement percentage allocable to the Company under the production sharing contract. Kikeh gas volumes offshore Sabah, Malaysia fell from 42.5 MMCF per day in 2012 to 29.7 MMCF per day in 2013 primarily due to more downtime for maintenance at the third party onshore receiving facility. Natural gas production from discontinued operations in the U.K. declined from 3.4 MMCF per day in 2012 to 0.8 MMCF per day in 2013 due to the Company selling these properties during the first half of 2013.

Natural gas sales volumes in the U.S. were 53.0 MMCF per day in 2012, up from 2011 production of 47.2 MMCF per day as higher gas volumes in the Eagle Ford Shale area more than offset declines at fields in the Gulf of Mexico. Natural gas volumes in Canada increased from 188.8 MMCF per day in 2011 to 217.0 MMCF per day in 2012 essentially due to higher gas volumes produced at the Tupper area, as more wells were on production at Tupper West during 2012. Natural gas sales volumes offshore Sarawak, Malaysia averaged 174.3 MMCF per day in 2012 following volumes of 176.9 MMCF per day in 2011. Gas sales at the Kikeh field averaged 42.5 MMCF per day in 2012, up from 40.5 MMCF per day during the prior year. Natural gas sales volumes in the U.K. reported as discontinued operations fell from 3.9 MMCF per day in 2011 to 3.4 MMCF per day in 2012 due to well decline at the Mungo/Monan field during the later year.

The Company s average worldwide realized sales price for crude oil, condensate and gas liquids from continuing operations was $93.60 per barrel in 2013 compared to $95.58 per barrel in 2012 and $94.18 per barrel in 2011.

The average realized oil sales price for continuing operations fell by 2% in 2013 compared to the prior year. Oil prices on various indices were mixed in 2013 compared to the prior year. Although West Texas Intermediate crude oil prices increased about 4% in 2013, most of the Company s oil is sold on other indices which actually declined in 2013 compared to 2012. Dated Brent prices and Kikeh benchmark prices declined in 2013 by about 3% and 2%, respectively. Compared to 2012, the Company s realized oil price in the U.S. declined by about 5% to $97.69 per barrel primarily due to a higher mix of natural gas liquids in the later year. This average 2013 oil price includes a mix of $101.70 per barrel for crude oil and $30.31 per barrel for natural gas liquids. Heavy oil price realizations in Canada increased 1% to $46.80 per barrel. Oil prices offshore Eastern Canada were $108.64 per barrel, down 3% from 2012. Oil produced at the Syncrude project averaged $96.09 per barrel in 2013, an increase of 5%. Malaysian crude oil was sold at an average of $94.27 per barrel in 2013, which was a decline of 3% from the prior year. Average crude oil sales prices in Republic of the Congo were $109.43 per barrel in 2013, a 2% increase from the prior year.

During 2012, the average realized oil sales price for continuing operations increased 1% compared to 2011. The 2012 higher realized price was favorable to the 1% reduction in West Texas Intermediate (WTI) sales price between the years. Other benchmark oil prices used for sale of Company crude oil, such as Dated Brent, performed more favorably than WTI. During 2012, the Company began to sell its Kikeh crude oil based on a new Kikeh benchmark price. Kikeh oil had been sold since late 2010 on a Brent crude oil benchmark. Compared to 2011, the Company s average 2012 crude oil sales prices fell 1% in the U.S. to average $102.60 per barrel. Heavy oil sales prices in Canada fell 19% in 2012 to an average of $46.45 per barrel. Offshore Canada oil sold at $112.08 per barrel in 2012, an increase of 2%. Canadian synthetic crude oil sold for 11% less in 2012 and averaged $91.85 per barrel. The crude oil sales price in Malaysia increased 8% to an average price of $97.29 per barrel in 2012. Crude oil sold in Republic of the Congo increased 4% to a price of $107.26 per barrel in 2012.

During 2013, the Company s realized North American natural gas sales price averaged $3.26 per thousand cubic feet (MCF), a 23% increase compared to 2012. Natural gas produced in 2013 offshore Sarawak was sold at an average price of $6.66 per MCF, a decline of 11% from 2012, which was essentially caused by contractually required revenue sharing for a higher percentage of gas produced during the just completed year.

The Company s North American natural gas prices retracted in 2012 compared to 2011, while prices in other areas were a bit stronger in 2012. North American natural gas sales prices were hurt by an oversupply of gas caused by both a growing profile of unconventional gas production on the continent and an unusually warm winter season in the primary gas consuming markets in the U.S. during 2012. The Company s average sales prices for natural gas in North America decreased 35% to $2.65 per MCF in 2012, which was composed of a 33% decline to $2.76 per MCF in the U.S. and a 36% decline to $2.62 per MCF in Canada. Natural gas produced offshore Sarawak sold for 6% more in 2012 than in 2011 and averaged $7.50 per MCF in the later year.

Based on 2013 sales volumes and deducting taxes at statutory rates, each $1.00 per barrel and $0.10 per MCF fluctuation in prices would have affected 2013 earnings from exploration and production continuing operations by $32.2 million and $10.4 million, respectively. The effect of these price fluctuations on consolidated net income cannot be measured precisely because operating results of the Company s discontinued refining and marketing operations could have been affected differently.

Production expenses for continuing operations were $1,340.2 million in 2013, $1,114.8 million in 2012 and $1,010.3 million in 2011. These amounts are shown by major operating area on pages F-57 and F-58 of this Form 10-K report. Costs per equivalent barrel sold, excluding ad valorem and severance taxes as applicable, during the last three years are shown in the following table.

(Dollars per equivalent barrel)	**2013**	2012	2011
United States	**$ 13.10**	17.64	17.30
Canada			
Excluding synthetic oil	**10.50**	8.86	8.55
Synthetic oil	**47.47**	43.26	46.84
Malaysia	**12.15**	12.78	13.66
Worldwide excluding synthetic oil and Republic of the Congo	**12.03**	12.61	12.69

Production expense per equivalent barrel in the U.S. declined in 2013 compared to 2012 due to both higher production volumes and cost management actions in the Eagle Ford Shale area. In 2013, costs per barrel in the Eagle Ford Shale were below the U.S. average rate. Continued cost management activities and anticipated higher production at the Eagle Ford Shale is expected to lead to lower U.S. production expense per barrel in 2014. The per-unit costs for Canadian conventional oil and gas operations, excluding synthetic oil, was higher in 2013 compared to 2012, which was caused by a higher mix of more expensive Seal area heavy oil coupled with a reduction in less expensive natural gas production in the Tupper and Tupper West areas. Lower maintenance costs anticipated in 2014 at the Terra Nova field should lead to a small reduction in per-unit costs in Canada in that year. Higher cost per barrel in 2013 compared to 2012 at Canadian synthetic oil operations was primarily caused by more overall maintenance costs and lower production volumes in the just completed year. No major variance in per-unit costs is anticipated at Syncrude in 2014. Production cost per unit in Malaysia was down in 2013 compared to 2012, with the reduction primarily associated with lower costs for the early production system at the Kakap-Gumusut field. A higher mix of oil-weighted production is anticipated to lead to an increase in per-unit costs in Malaysia in 2014. Production expense in Republic of the Congo in 2013 included $82.5 million related to abandonment and other exit activities at the Azurite field. These costs will not repeat in 2014 and due to field shutdown in late 2013, the effect of Azurite production has been omitted from the table on page 32.

Production expense per equivalent barrel in the U.S. increased in 2012 compared to 2011 due to a significantly larger proportion of production in the later year coming from the Eagle Ford Shale in South Texas, where the average per-barrel cost exceeded the U.S. average. Cost per barrel for Canada conventional oil and gas operations, excluding synthetic oil, was higher in 2012 than 2011 due to additional maintenance costs in the later year at the Terra Nova field. This Canadian cost increase was tempered by higher natural gas production at the lower cost Tupper area. The reduction in production costs per barrel for synthetic oil operations in 2012 compared to 2011 was attributable to lower natural gas power costs in the later year. Production expense in Malaysia declined in 2012 compared to 2011 due to less well maintenance and workover costs at the Kikeh field. Per-barrel production expense in 2012 in Republic of the Congo was significantly higher than 2011 due to lower production levels and unsuccessful workover costs at a well in the Azurite field.

Exploration expenses for continuing operations for each of the last three years are shown in total in the following table, and amounts are reported by major operating area on pages F-57 and F-58 on this Form 10-K report. Expenses other than undeveloped lease amortization are included in the capital expenditures total for exploration and production activities.

(Millions of dollars)	**2013**	2012	2011
Dry holes	**$ 262.9**	181.9	251.0
Geological and geophysical	**117.5**	32.2	79.3
Other	**54.9**	37.0	40.9
	435.3	251.1	371.2
Undeveloped lease amortization	**66.9**	129.8	118.2
Total exploration expenses	**$ 502.2**	380.9	489.4

Dry hole expense in 2013 was $81.0 million more than 2012 due to higher unsuccessful exploratory drilling costs in the just completed year in the Gulf of Mexico, Western Canada, Australia and Cameroon. Lower dry hole costs in 2013 in Malaysia, Republic of the Congo and Kurdistan somewhat offset the higher costs in other areas. Geological and geophysical (G&G) expenses were $85.3 million higher in 2013 compared to 2012. The increase in G&G expenses in 2013 was mostly attributable to higher spending on seismic in Vietnam, Indonesia, Australia, West Africa and the Gulf of Mexico, but 2013 included lower seismic spending offshore Malaysia. Other exploration costs were $17.9 million more in 2013 than 2012 mostly due to higher office costs for exploration activities primarily in West Africa, the Kurdistan region of Iraq, Vietnam and Australia. Undeveloped lease amortization expense was $62.9 million lower in 2013 than 2012 principally due to less unproved lease amortization costs associated with concessions in the Kurdistan region of Iraq, the Eagle Ford Shale area and Western Canada.

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Dry hole expense was $69.1 million lower in 2012 than in 2011 due to better drilling success coupled with lower exploratory drilling spending. Dry hole expense in 2012 in other foreign areas was significantly lower than in 2011 primarily due to unsuccessful wells drilled in the earlier year in Brunei, Indonesia and Suriname. Dry hole expense in Canada was also significantly lower in 2012 due to fewer unsuccessful wells drilled in Southern Alberta in 2012. Dry hole expense in the U.S. was higher in 2012 mostly due to a decision by the owners in 2012 not to develop a well drilled in a prior year in the deepwater Gulf of Mexico; the well was expensed in 2012. Malaysian operations had higher dry hole expense in 2012 due to an unsuccessful well drilled in Block P and expensing of two wells drilled in a prior year offshore Sarawak caused by a decision to forego development plans for these wells. Dry hole expense in Republic of the Congo was higher in 2012 than 2011 due to expensing two wildcat wells following unsuccessful drilling in the MPN block in the later year. G&G expenses were $47.1 million lower in 2012 than 2011. Areas with lower spending on seismic in 2012 included the Gulf of Mexico, Brunei, the Kurdistan region of Iraq, and Block H Malaysia. Other exploration costs in 2012 were $3.9 million below 2011 levels primarily due to lower lease rentals on undeveloped acreage in Western Canada in 2012. Undeveloped leasehold amortization expense rose $11.6 million in 2012 compared to 2011, primarily due to higher amortization associated with Eagle Ford Shale area leases.

The Company s E&P operations had lower impairment expense of $178.4 million in 2013 when compared to the prior year. The 2013 expense was associated with a writedown of property value in the Kainai area of Western Canada based on a sale of the property at a price below the carrying value. In 2012, the Company recorded an impairment charge of $200.0 million for oil production operations at the Azurite field, offshore Republic of the Congo. The 2012 charge for Azurite was required due to the removal of all proved reserves at year-end 2012 following the Company s decision to cease redrilling operations on a well that went off production during that year. The reserves associated with the remaining producing wells were insufficient to allow for booking as proved reserves due to uneconomic results. A $368.6 million impairment charge was recorded in 2011 to reduce the carrying value of Azurite necessitated by a reduction in the field s proved oil reserves at year-end 2011 due to poor performance for certain wells.

Depreciation, depletion and amortization expense for continuing exploration and production operations totaled $1,543.6 million in 2013, $1,244.4 million in 2012 and $956.0 million in 2011. The $299.2 million increase in 2013 was attributable to a combination of higher total sales volumes on a barrel equivalent basis and a higher per-unit depreciation rate. Additional production volumes at the Eagle Ford Shale and new oil produced at fields offshore Sarawak had higher overall per-unit rates compared to the average rate for the Company. The $288.4 million increase in 2012 compared to 2011 was primarily caused by higher overall volumes of oil and natural gas sold during 2012. Additionally, the average per-unit depreciation rate increased in 2012, primarily due to a higher mix of production from the Eagle Ford Shale and a higher unit rate at Kikeh due to development drilling activities at the field.

The exploration and production business recorded expenses of $49.0 million in 2013, $38.4 million in 2012 and $33.8 million in 2011 for accretion on discounted abandonment liabilities. Because the liability for future abandonment of wells and other facilities is carried on the balance sheet at a discounted fair value, accretion must be recorded annually so that the liability will be recorded at full value at the projected time of abandonment. The $10.6 million increase in accretion expense in 2013 compared to the prior year was due to additional wells drilled in the Eagle Ford Shale area, as well as higher estimated abandonment liabilities for synthetic oil operations in Canada and oil fields in Malaysia and Congo. The $4.6 million increase in accretion expense in 2012 compared to 2011 was due to additional wells drilled during the later year in Malaysia and higher estimated abandonment costs for wells in the Gulf of Mexico and for synthetic oil operations at Syncrude.

The effective income tax rate for exploration and production continuing operations was 38.9% in 2013, 40.1% in 2012 and 52.6% in 2011. The 2013 overall effective tax rate for E&P operations was slightly lower than 2012 due to recognizing higher U.S. income tax benefits associated with investments in upstream operations in Republic of the Congo and Kurdistan, where the Company is exiting. These U.S. benefits amounted to $133.5 million in 2013. The effective income tax rate was significantly lower in 2012 than 2011 mostly due to

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U.S. income tax benefits of $108.3 million recorded in 2012 associated with investments in upstream operations in Republic of the Congo and Suriname. Additionally, 2012 had lower exploration expenses in foreign jurisdictions where no tax benefit is available at the present time due to lack of available revenue needed to realize a current or future benefit. Income tax expense in 2011 was reduced by a $25.6 million benefit for expenses incurred in prior years in Block P, Malaysia. It was determined during 2011 that Block P expenses are deductible against taxable income generated in Block K Malaysia. The effective tax rates in all three years exceeded the U.S. statutory tax rate of 35.0% due to higher overall foreign tax rates and exploration and other expenses in areas where current tax benefits cannot be recorded by the Company. Tax jurisdictions with no current tax benefit on expenses primarily include certain non-revenue generating areas in Malaysia as well as other foreign exploration areas in which the Company operates. Each main exploration area in Malaysia is currently considered a distinct taxable entity and expenses in certain areas may not be used to offset revenues generated in other areas. No tax benefits have thus far been recognized for costs incurred for Block H, offshore Sabah, and Blocks PM 311/312, offshore Peninsular Malaysia.

At December 31, 2013, 125.8 million barrels of the Company s U.S. proved oil reserves and 72.4 billion cubic feet of U.S. proved natural gas reserves were undeveloped. Approximately 93% of the total U.S. undeveloped reserves (on a barrel of oil equivalent basis) are associated with the Company s Eagle Ford Shale operations in South Texas. Further drilling and facility construction are generally required to move the undeveloped reserves in the Eagle Ford Shale area to developed. In the Western Canadian Sedimentary Basin, total proved undeveloped natural gas reserves totaled 178.8 billion cubic feet, with the migration of these reserves, primarily in the Tupper and Tupper West areas, dependent on both development drilling and completion of processing and transportation facilities. In Block K Malaysia, oil reserves of 33.9 million barrels for the Kakap-Gumusut field are undeveloped pending completion of the main facilities and additional development drilling directed by another company. Additionally, the Kikeh field had undeveloped oil reserves of 7.7 million barrels, which are subject to further drilling before being moved to developed, and the Siakap North-Petai field had undeveloped oil reserves of 5.7 million barrels pending completion of development facilities. Also in Malaysia, there were 99.3 billion cubic feet of undeveloped natural gas reserves at various fields offshore Sarawak at year-end 2013, which were held under the undeveloped category pending completion of development drilling and facilities. The deepwaters of the Gulf of Mexico accounted for additional proved undeveloped reserves of 9.5 million equivalent barrels of oil at December 31, 2013. On a worldwide basis, the Company spent approximately $3.40 billion in 2013, $3.30 billion in 2012 and $1.88 billion in 2011 to develop proved reserves.

Refining and Marketing On August 30, 2013, the Company spun-off to shareholders its U.S. retail marketing business. The now separate, publicly traded U.S. retail company named Murphy USA Inc. is listed on the New York Stock Exchange under the symbol MUSA . Murphy Oil continues to actively market for sale its U.K. refining and marketing business. Both the U.S. and U.K. downstream businesses are reported as discontinued operations for all periods presented. Further discussion of the results of discontinued operations is included following the Corporate section.

Corporate The after-tax costs of corporate activities, which include interest income, interest expense, foreign exchange gains and losses, and unallocated corporate overhead were $140.7 million in 2013, $98.5 million in 2012 and $75.0 million in 2011.

The net cost of corporate activities in 2013 was $42.2 million more than in 2012, primarily due to higher net interest and administrative expenses. These were partially offset by more favorable effects of foreign currency exchange, which were associated with transactions denominated in currencies other than the respective operation s predominant functional currency. Interest income in 2013 was $2.5 million less than 2012, principally due to lower invested cash balances in Canada during the later year. Net interest expense, after capitalization of finance-related costs to development projects, was $57.0 million higher in 2013 than 2012. This unfavorable variance was principally due to higher average debt levels in the current year coupled with a higher average interest rate caused by a full year of long-term notes that were sold in 2012. These were partially offset by higher amounts of interest capitalized to development projects in Malaysia in 2013. Administrative expenses

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associated with corporate activities were $78.3 million higher in 2013 compared to 2012, primarily associated with higher overall employee compensation costs and professional service expenses related to separation of the U.S. downstream business. The effect of foreign currency exchange after taxes was a gain of $70.3 million in 2013 compared to a minimal impact in 2012. The most significant impact from foreign currencies occurred in Malaysia, where the U.S. dollar generally strengthened against the Malaysian ringgit in 2013 after having weakened against this currency during 2012. The stronger U.S. currency in 2013 reduced the dollar cost of tax liabilities in Malaysia which are payable in the local currency. The Malaysian operation s functional currency is the U.S. dollar. Foreign currency transaction effects in the U.K. were also favorable in 2013 compared to 2012. Income tax benefits associated with Corporate activities were $28.3 million higher in 2013, essentially in line with the larger pretax net costs in the current year.

The net cost of corporate activities rose $23.5 million in 2012 compared to 2011. The most significant variance between years related to the effects of foreign currency exchange. While 2011 benefited from after-tax gains of $20.7 million from foreign currency exchange, the foreign currency effects in 2012 were minimal. During 2012, the after-tax impact of foreign exchange losses for Malaysian operations was essentially offset by after-tax foreign exchange benefits in the U.K. Interest income was $3.6 million less in 2012 compared to the prior year, with the variance primarily related to interest earned in 2011 on a U.S. Federal royalty refund. Administrative expenses for corporate activities were up $18.8 million in 2012 compared to 2011 due to both higher employee compensation and higher professional services costs. The increase in professional services in 2012 was primarily associated with both preparing for separation of the U.S. R&M business and the intended sale of the U.K. R&M business. Net interest expense, after capitalization of finance-related costs to development projects, was $25.8 million lower in 2012 than 2011 mostly due to larger amounts of interest capitalized on oil development projects during 2012. Income taxes associated with corporate activities in 2012 were unfavorable to 2011 primarily due to pretax variances from foreign currency exchange effects.

Discontinued Operations The Company has presented a number of businesses as discontinued operations in its consolidated financial statements. These businesses principally include:

U.S. retail marketing company spun-off to shareholders on August 30, 2013. Results of operations are included in the Company s financial statements through the date of spin-off.

U.K. refining and marketing company held for sale at year-end 2013.

U.K. oil and gas assets sold through a series of transactions in the first half of 2013. The Company s financial statements include the results of operations through the respective date of asset sale, plus the cumulative gain realized upon sale. Total cash proceeds from sale of these assets were $282.2 million.

Two former refineries in the U.S. that were sold on September 30, 2011 and October 1, 2011. The Company s financial statements include the results of these operations through the date of sale, plus the net gain associated with the disposals. Total cash proceeds from sale of these refineries amounted to $950.0 million.

The results of these operations for the last three years are reflected in the following table.

(Millions of dollars)	**2013**	2012	2011
U.S. refining and marketing	**$ 134.8**	87.3	355.3
U.K. refining and marketing	**(119.2)**	52.2	(33.3)
U.K. exploration and production	**219.8**	24.9	11.5
Income from discontinued operations	**$ 235.4**	164.4	333.5

The U.S. refining and marketing (R&M) operations had better operating results in 2013 than 2012 primarily due to an impairment charge of $61.0 million in 2012 ($39.6 million after taxes) to writedown the carrying value of an ethanol plant. The U.K. R&M business incurred losses in 2013 following gains in 2012 due to both

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significantly weaker margins at the Milford Haven, Wales refinery and a $73.0 million charge to writedown the carrying value of the U.K. assets at year-end 2013. The overall composite unit margin for the U.K. R&M business was a negative $0.75 per barrel in 2013, down from a positive $1.94 per barrel in 2012. The U.K. E&P results shown above include an after-tax gain on sale of $216.1 million in 2013, but operating profits were lower in 2013 than 2012 due to only a partial year of operations prior to the property sales in the current year versus a full year of operations in the prior year. In 2012, U.S. R&M results were significantly below 2011 due to a combination of lower retail marketing margins, unfavorable results, including the impairment charge noted above, for ethanol production operations in the later year, no repeat of U.S. refinery operating profits of $113.1 million from 2011, and a nonrecurring net gain after taxes of $18.7 million in 2011 on sale of the two refineries. The net gain from disposal of the two refineries included a gain on sale of the Superior refinery and associated inventories of $77.6 million and a loss on sale of the Meraux refinery and associated inventories of $58.9 million. The net gain on disposal was based on the selling prices of the refineries, plus the sales of all associated inventories at fair value, which was significantly above the last-in, first-out carrying value of these assets. U.K. R&M operations had much stronger results in 2012 compared to 2011 primarily due to stronger refining margins in the later year. Overall unit margins were a positive $1.94 per barrel in 2012 and a negative $0.67 per barrel in 2011. The higher operating results for the U.K. E&P business in 2012 compared to 2011 was mostly attributable to lower tax charges during the later year. In July 2012, the United Kingdom enacted tax changes that limited tax relief on oil and gas decommissioning costs to 50%, a reduction from the 62% tax relief previously allowed for these costs. This tax rate change led to a net reduction of income from this discontinued operation of $5.5 million in 2012. In 2011, the U.K. government enacted a 12% supplemental tax on oil and gas company profits in that country. This tax increase reduced income from discontinued operations in 2011 by $14.5 million, primarily to increase the recorded balance for deferred income taxes that will be paid in future years at the new higher rate. The 2011 rate change increased the effective tax rate to 62% for oil and gas operations in the U.K.

Capital Expenditures

As shown in the selected financial data on page 24 of this Form 10-K report, capital expenditures from continuing operations, including exploration expenditures, were $3.97 billion in 2013, compared to $4.19 billion in 2012, and $2.75 billion in 2011. These amounts excluded capital expenditures of $154.6 million in 2013, $190.9 million in 2012 and $190.6 million in 2011 related to discontinued operations, which were associated with U.K. refining and marketing operations held for sale at the end of 2013, U.S. retail marketing operations spun-off in August 2013, two U.S. petroleum refineries sold during 2011, and U.K. oil and gas assets sold in the first half of 2013. Capital expenditures included $435.3 million, $251.1 million and $371.2 million, respectively, in 2013, 2012 and 2011 for exploration costs that were expensed.

Capital expenditures for exploration and production continuing operations totaled $3.94 billion in 2013, $4.19 billion in 2012 and $2.75 billion in 2011. E&P capital expenditures in 2013 included $35.6 million for lease acquisitions, $493.7 million for exploration activities, and $3.41 billion for development projects. Lease acquisitions were primarily related to acreage extensions in the Eagle Ford Shale area. Exploration activities included exploratory drilling primarily in the Gulf of Mexico, Australia, Cameroon and Brunei. Exploratory activities also included seismic and other geophysical costs primarily in the U.S., Australia, Indonesia, Vietnam and West Africa. Development expenditures in 2013 included $1.48 billion for the drilling and completion program in the Eagle Ford Shale; $230.9 million for fields in the Gulf of Mexico including Dalmatian which starts up in 2014; $156.7 million for synthetic oil operations; $140.4 million for heavy oil at Seal; $283.5 million for Kikeh; $136.7 million for Kakap-Gumusut; $214.6 million for Siakap North-Petai; $681.3 million for Sarawak oil fields; and $49.6 million for Hibernia and Terra Nova offshore Newfoundland.

E&P capital expenditures in 2012 included $132.5 million for acquisition of undeveloped leases, which primarily included leases acquired in the Gulf of Mexico, the Eagle Ford Shale area of South Texas and in Northwest Alberta, Canada, $450.6 million for exploration activities, $3.29 billion for development projects and $311.5 million for acquisition of proved properties in Canada and the Gulf of Mexico. Exploration activities primarily included exploratory drilling in the United States, Southern Alberta in Canada, Block H in Malaysia, Republic of the Congo, the Kurdistan region of Iraq and Brunei. Other primary exploration activities were associated with geophysical data acquisitions in the U.S. and various foreign countries. Development expenditures included $1.11 billion in the Eagle Ford Shale; $157.3 million at the Tupper and Tupper West areas; $200.1 million for deepwater fields in the Gulf of Mexico; $627.8 million for Kikeh; $558.6 million for oil and natural gas development activities in SK Blocks 309/311; $107.0 million and $83.9 million for the Kakap-Gumusut and Siakap North-Petai developments, respectively, in Block K, Malaysia; $125.1 million for Syncrude; $222.4 million for Western Canada heavy oil projects; and $73.1 million for the Terra Nova and Hibernia oil fields.

Capital expenditures in 2011 from E&P continuing operations included $279.3 million for undeveloped lease acquisitions, $23.5 million associated with a contract revision at the Azurite field, $559.7 million of exploration activities and $1.89 billion for development programs. Lease acquisitions were primarily associated with activities in the Eagle Ford Shale area of South Texas and exploration concessions in the Kurdistan region of Iraq. Exploration costs principally related to exploratory drilling at resource plays in North America, including the Eagle Ford Shale in South Texas and new areas in Southern Alberta, plus wildcat drilling activities in Brunei, Indonesia and Suriname. Development projects in 2011 primarily included spend of $572.2 million at the Tupper and Tupper West natural gas areas in Western Canada; $153.7 million for Seal heavy oil area activities; $339.6 million for the Kikeh field in Malaysia; $236.4 million for Sarawak SK Blocks 309/311 oil and gas projects offshore Malaysia; $115.7 million for the Kakap-Gumusut field in Block K, offshore Sabah Malaysia; $219.7 million for work in the Eagle Ford Shale; and $73.9 million for synthetic oil operations at Syncrude.

Exploration and production capital expenditures are shown by major operating area on page F-56 of this Form 10-K report.

Capital expenditures for discontinued operations included $114.3 million in 2013, $111.5 million in 2012 and $101.2 million in 2011 for U.S. retail marketing operations, which primarily included station construction and other improvements in each year. U.S. refining operations had capital expenditures of $47.0 million in 2011. U.K. refining and marketing operations had capital expenditures during the three years ended December 31, 2013 of $32.2 million, $22.2 million and $22.2 million, respectively. U.K. E&P operations had capital expenditure of $8.1 million in 2013, $57.2 million in 2012 and $20.2 million in 2011.

Cash Flows

Operating activities Cash provided by operating activities was $3.64 billion in 2013, $3.06 billion in 2012 and $2.15 billion in 2011. Cash flows associated with formerly owned U.S. downstream and U.K. oil and gas production businesses, plus the held for sale U.K. downstream businesses, have been classified as discontinued operations in the Company s consolidated financial statements. Cash provided by operating activities included cash from these discontinued operations of $427.8 million in 2013, $144.9 million in 2012 and $456.5 million in 2011. Cash flow provided by continuing operations was $299.3 million higher in 2013 compared to 2012. The increase in 2013 was attributable to higher income from continuing operations, plus higher dry hole costs, higher depreciation expense and a favorable impact from changes in working capital other than cash compared to the prior year. Cash provided by continuing operations in 2012 was $1.22 billion more than 2011 primarily due to a lower use of cash to build working capital other than cash, higher income from continuing operations, and higher non-cash expenses for depreciation and deferred taxes in 2012. Cash provided by operating activities was reduced by expenditures for abandonment of oil and gas properties totaling $51.6 million in 2013, $40.4 million in 2012 and $21.5 million in 2011. Operating cash flows were reduced by payments of income taxes of $457.0 million in 2013, $567.0 million in 2012 and $938.9 million in 2011. The total reductions of operating cash flows for interest paid during the three years ended December 31, 2013, 2012 and 2011 were $113.0 million, $48.7 million and $53.3 million, respectively.

Investing activities Capital expenditures of the exploration and production business represent the most significant component of investing activities. Property additions and dry hole costs for continuing operations used cash of $3.59 billion in 2013, $3.54 billion in 2012 and $2.43 billion in 2011. Cash of $923.5 million,

$1.62 billion and $1.69 billion was spent in 2013, 2012 and 2011, respectively, to acquire Canadian government securities with maturities greater than 90 days at the time of purchase. Proceeds from maturities of Canadian government securities with maturities greater than 90 days at date of acquisition were $664.3 million in 2013, $2.04 billion in 2012 and $1.77 billion in 2011. Cash proceeds of $27.4 million in 2011 from property sales classified as continuing operations primarily related to disposal of gas storage assets in Spain. In 2013, the sale of all U.K. oil and gas assets generated cash of $282.2 million. In 2011, the Company generated cash of $950.0 million from sale of two U.S. refineries and associated marketing assets, including liquid inventories. Cash utilized for other investing activities of discontinued operations totaled $165.7 million in 2013, $192.5 million in 2012 and $246.1 million in 2011 and mostly related to cash payments for capital expenditures.

Financing activities During 2013, the Company borrowed additional long-term debt of $350.0 million, and primarily used these borrowings to fund a portion of its capital program. The Company paid $500.0 million in 2013 and $250.0 million in 2012 to repurchase 7.66 million shares and 3.87 million shares, respectively, of its Common stock. The Company received 0.28 million additional shares of its stock in 2014 upon completion of an accelerated share repurchase agreement with a major financial institution that was still open at the end of 2013. Through December 31, 2013, the Company has spent $750.0 million of a $1.0 billion share buyback program approved by the Board of Directors. Cash used for dividends to stockholders was $235.1 million in 2013, $714.4 million in 2012 and $212.8 million in 2011. The Company increased its normal dividend rate by 14% in 2012 as the annualized dividend was raised from $1.10 per share to $1.25 per share effective in the third quarter 2012. Additionally, in December 2012, the Company paid a special dividend of $2.50 per share. At the date of the spin-off, Murphy USA Inc. paid Murphy Oil Corporation cash of $650.0 million, which the Company primarily used to partially repay outstanding debt. However, Murphy USA retained cash of $55.5 million at the time of the separation. At December 31, 2013, the Company s held for sale U.K. downstream business had cash of $301.3 million. This cash is classified within current assets held for sale on the Consolidated Balance Sheet at year-end 2013, effectively removing this amount from the Company s reported cash balance. During 2012, the Company sold $2.0 billion of long-term notes. The proceeds of these notes were primarily used to repay $350.0 million of notes that matured in 2012, to repay other debt, to fund a special dividend totaling $486.1 million, to fund a $250.0 million repurchase of Common stock, and to fund a portion of the Company s development capital expenditures. During 2011, the Company used available cash flow to repay $340.0 million of debt. The debt reduction in 2011 was accomplished with proceeds from sale of the two U.S. refineries. Cash proceeds from stock option exercises and employee stock purchase plans, including income tax benefits received on stock options, amounted to $4.2 million in 2013, $15.0 million in 2012 and $20.4 million in 2011. In 2013, the Company paid $3.3 million of fees to increase the size of its committed credit facility from $1.5 billion to $2.0 billion and to extend the maturity date by one year to June 2017. In 2012, the Company paid $7.0 million of fees and other expenses associated with sales of $2.0 billion of long-term notes. In 2011, the Company used cash of $7.9 million for fees and other expenses associated with renewing its primary $1.5 billion committed credit facility that has now been increased to $2.0 billion of capacity. In 2013, 2012 and 2011, cash of $16.7 million, $3.3 million and $8.0 million, respectively, was used to pay statutory withholding taxes on stock-based incentive awards that vested with a net-of-tax payout.

Financial Condition

Year-end working capital (total current assets less total current liabilities) amounted to $284.6 million at year-end 2013 and $699.5 million in 2012. The current level of working capital does not fully reflect the Company s liquidity position as the carrying value for inventories under last-in, first-out accounting was $268.6 million below fair value for the held for sale U.K. downstream operations at December 31, 2013. Cash and cash equivalents at the end of 2013 totaled $750.2 million compared to $947.3 million at year-end 2012. In addition, the Company had short-term investments in Canadian government treasury securities of $374.8 million at year-end 2013, up $259.2 million compared to 2012. These short-term Canadian government investments could quickly be converted to cash if a need for funds in Canada arose.

Long-term debt increased by $691.4 million in 2013. Of this increase, $342.0 million related to a non-cash capital lease of production equipment at the Kakap-Gumusut field, offshore Malaysia. The remainder of the debt increase in 2013 was necessitated by a combination of capital expenditures, share buybacks and cash dividends, which in total exceeded cash generated from operating activities, sale of assets, and amounts paid to the Company by Murphy USA Inc. at the separation date. At December 31, 2013, long-term debt was 25.5% of total capital employed. During 2012, long-term debt increased by $2.00 billion. A portion of the increase in long-term debt in 2012 was associated with issuance of $500.0 million of long-term notes in May 2012. The proceeds from these notes were partially used to repay $350.0 million of notes that matured in May 2012. In late 2012, the Company sold an additional $1.5 billion of long-term notes in the market. Part of the proceeds of these notes were used to pay a $2.50 per share special dividend that totaled $486.1 million and to fund a $250.0 million stock buyback. The remainder of the note proceeds were used to repay debt that was then outstanding under the Company s committed credit facility and to fund capital expenditures. At December 31, 2012, long-term debt represented 20.1% of total capital employed. Stockholders equity was $8.60 billion at the end of 2013 compared to $8.94 billion at the end of 2012 and $8.78 billion at the end of 2011. Stockholders equity declined in 2013 principally due to the spin-off of Murphy USA Inc. and Common stock repurchases during the year. A summary of transactions in stockholders equity accounts is presented on page F-8 of this Form 10-K report.

Other changes in Murphy s year-end 2013 balance sheet compared to 2012 included a $259.2 million increase in the balance of short-term investments in Canadian government securities with maturities greater than 90 days at the time of purchase. The total investment in these Canadian government securities was $374.8 million at year-end 2013 and $115.6 million at year-end 2012. These short-term investments increased in 2013 primarily due to repayment of an intercompany loan to the Company s Canadian subsidiary by the U.K. downstream business in early 2013. These slightly longer-term Canadian investments were purchased in each year because of a tight supply of shorter-term securities available for purchase in Canada. A $853.5 million decrease in accounts receivable in 2013 was primarily caused by the separation of Murphy USA Inc. (MUSA) on August 30, 2013 and the reclassification of the U.K. downstream business as held for sale at year-end 2013. Inventory values were $458.1 million less at year-end 2013 than in 2012 mostly due to the MUSA separation and U.K. downstream held for sale reclassification. Prepaid expenses decreased $252.0 million in 2013 primarily due to collection of a refund of prepaid U.S. income taxes during 2013. Short-term deferred income tax assets were $27.0 million lower at year-end 2013 compared to 2012 mostly due to reclassification of U.K. downstream deferred tax assets to held for sale classification at year-end 2013. Current assets held for sale amounted to $943.7 million at December 31, 2013 and $15.1 million at December 31, 2012. The year-end 2013 amount primarily consisted of cash, accounts receivable and inventory held by the U.K. downstream business, while the 2012 amounts primarily represented accounts receivable and crude oil and other inventory costs associated with U.K. oil and gas producing assets sold in the first half of 2013. Net property, plant and equipment increased by $469.4 million in 2013 as the level of property additions during the year exceeded the cumulative property amounts either spun-off in the MUSA separation, reclassified to held for sale for the U.K. downstream business or depreciated during the year. Goodwill decreased $2.8 million in 2013 due to a weaker Canadian dollar exchange rate versus the U.S. dollar at year-end 2013 compared to the prior year. Deferred charges and other assets decreased $53.1 million in 2013 primarily due to deferred turnaround costs and other assets associated with the Milford Haven refinery being reclassified to assets held for sale. Assets held for sale-noncurrent of $381.4 million at December 31, 2013 related to property and equipment, deferred turnaround costs and other noncurrent assets of the U.K. downstream business, while the $208.2 million balance at year-end 2012 represented property and equipment associated with U.K. oil and gas producing assets sold in the first half of 2013. Current maturities of long-term debt at year-end 2013 was $26.2 million higher than at the prior year-end due to 2014 payment obligations on a new capital lease covering production equipment at the Kakap-Gumusut field, offshore Malaysia. Accounts payable decreased by $644.8 million at year-end 2013 compared to 2012 primarily due to lower capital and operating expenses owed to vendors in the U.S., Malaysia and Republic of the Congo at year-end 2013, plus reclassification of amounts owed for purchased crude oil feedstocks at the Milford Haven refinery to current liabilities associated with assets held for sale in 2013. Income taxes payable was $3.1 million higher at year-end 2013 than at the end of 2012, primarily due to higher levels of taxes owed in 2013 for Malaysian operations. Other taxes payable at year-end 2013 was $165.9 million lower than in 2012 mostly due to excise taxes owed by U.K. downstream operations being reclassified to held for sale and the 2013 separation of the U.S. downstream business. Other accrued liabilities increased by $7.3 million at year-end 2013 mostly due to higher amounts owed for employee

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compensation. The current portion of deferred income tax liabilities decreased $2.6 million in 2013 due to nonrecurring short-term temporary differences for tax deductions in Canada in the prior year. Current liabilities associated with assets held for sale of $639.1 million at December 31, 2013 primarily represented accounts payable and accrued liabilities for the U.K. downstream business held for sale. The comparable amount of $47.5 million at December 31, 2012 mostly consisted of U.K. oil and gas operations payables to vendors and tax authorities. Noncurrent deferred income tax liabilities were $78.2 million lower at year-end 2013 mostly due to separation of U.S. downstream operations and reclassification of the U.K. downstream balances to noncurrent liabilities associated with assets held for sale, partially offset by higher balances for remaining E&P operations for accelerated tax depreciation associated with the Company s 2013 capital expenditures in the U.S. and Malaysia. The non-current liability associated with future asset retirement obligations increased by $128.2 million at year-end 2013 mostly due to additional wells drilled in 2013 and higher estimated future costs to abandon oil and gas properties in the U.S., Canada and Malaysia. Deferred credits and other liabilities were $177.5 million less in 2013 compared to 2012 primarily due to lower noncurrent retirement and postretirement plan liabilities and other long-term obligations at year-end 2013. Non-current liabilities associated with assets held for sale of $95.5 million at December 31, 2013 primarily represented deferred tax and pension liabilities of the U.K. downstream business, while the December 2012 balance of $141.2 million primarily represented abandonment and deferred tax obligations associated with U.K. oil and gas assets sold in 2013. Total stockholders equity of the Company decreased by $346.3 million in 2013. The components of this decrease in stockholders equity are reflected in the Consolidated Statement of Stockholders Equity on page F-8 of the consolidated financial statements.

Murphy had commitments for future capital projects of approximately $1.84 billion at December 31, 2013. These commitments included $706.9 million for field development and future work in Malaysia, $561.4 million for work in the Eagle Ford Shale, $184.8 million for costs to develop deepwater Gulf of Mexico fields, and $78.9 million, $78.0 million and $76.2 million for future work commitments offshore Cameroon, Equatorial Guinea and Vietnam, respectively.

The primary sources of the Company s liquidity are internally generated funds, access to outside financing and working capital. The Company uses its internally generated funds to finance the major portion of its capital and other expenditures, but it also maintains lines of credit with banks and borrows as necessary to meet spending requirements. At December 31, 2013, the Company had access to a long-term committed credit facility in the amount of $2.0 billion. A total of $350.0 million was borrowed under the committed credit facility at year-end 2013, leaving an additional $1.65 billion available for future needs. The most restrictive covenants under this committed credit facility limit the Company s long-term debt to capital ratio (as defined in the agreements) to 60%. The committed credit facility expires in June 2017. At December 31, 2013, the Company had uncommitted bank credit lines of approximately $345.0 million, but no borrowings were outstanding under these lines. The Company s ratio of long-term debt to total capital was 25.5% at year-end 2013. In October 2012, the Company filed a Form S-3 registration statement with the U.S. Securities and Exchange Commission which permits the offer and sale of debt and/or equity securities. The Company used this shelf registration and a former one to sell long-term notes totaling $2.0 billion in 2012. The current shelf registration will expire in October 2015. Current financing arrangements are set forth more fully in Note E to the consolidated financial statements. Based on the anticipated level of capital expenditures the Company has budgeted during 2014, the Company anticipates that it will need to borrow under its long-term credit facility during 2014. The Company s ratio of earnings to fixed charges was 9.5 to 1 in 2013, 15.1 to 1 in 2012 and 13.0 to 1 in 2011.

Cash and invested cash are maintained in several operating locations outside the United States. At December 31, 2013, cash, cash equivalents and cash temporarily invested in Canadian government securities with greater than 90 day maturities held outside the U.S. included $421.1 million in Canada and $620.1 million in Malaysia. In certain cases, the Company could incur taxes or other costs should these cash balances be repatriated to the U.S. in future periods. This could occur due to withholding taxes and/or potential additional U.S. tax burden when less than the U.S. tax rate of 35% has been paid for cash taxes in foreign locations. A lower cash tax rate is often paid in the U.S. and foreign countries in the early years of operations when accelerated tax deductions exist to incent oil and gas investments; cash tax rates are generally higher in later years after accelerated tax deductions in early years are exhausted. Canada collects a 5% withholding tax on any cash repatriated to the U.S. See Note H of the consolidated financial statements for further information regarding potential tax expense that could be incurred upon distribution of foreign earnings back to the United States.

Environmental Matters

Murphy and other companies in the oil and gas industry are subject to numerous federal, state, local and foreign laws and regulations dealing with the environment. Virtually all operations of the Company are affected by laws and regulations covering environmental, health and safety matters. Compliance with existing and anticipated environmental regulations affects Murphy s overall cost of business, including capital costs to construct, maintain and upgrade equipment and facilities, and operating costs for ongoing environmental compliance. Murphy s competitive position may be impacted to the extent that regulatory requirements with respect to a particular production technology may give rise to costs that competitors might not bear. Environmental regulations have historically been subject to frequent change by regulatory authorities and these are expected to continue to evolve in the foreseeable future. The Company is unable to predict the ongoing cost of complying with these laws and regulations or the future impact of such regulations on its operations. Violation of federal or state environmental laws, regulations and permits can result in the imposition of significant civil and criminal penalties, injunctions and construction bans or delays. A discharge of hazardous substances into the environment could, to the extent such event is not insured, subject Murphy to substantial expense, including both the cost to comply with applicable regulations and claims by neighboring landowners and other third parties for any personal injury and property damage that might result. See page 18 for discussion of insurance coverage maintained by the Company.

Murphy allocates a portion of its capital expenditure program to comply with environmental laws and regulations, and such capital expenditures were approximately $79 million in 2013 and are projected to be approximately $104 million in 2014.

The most significant of those laws and the corresponding regulations affecting Murphy s operations are:

- The U.S. Clean Air Act, which regulates air emissions, including greenhouse gas emissions
- The U.S. Clean Water Act, which regulates discharges into U.S. waters
- The U.S. Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which addresses liability for hazardous substance releases
- The U.S. Federal Resource Conservation and Recovery Act (RCRA), which regulates solid waste and hazardous waste treatment, storage and disposal
- The U.S. Federal Oil Pollution Act of 1990 (OPA90), which addresses liability for discharges of oil into navigable waters of the United States
- The U.S Safe Drinking Water Act, which regulates disposal of wastewater into underground injection wells
- The Federal Water Pollution Control Act of 1972 (FWPCA) also addressing discharge of pollutants into navigable waters
- The Department of the Interior governing offshore oil and gas operations.

The European Union Regulation for Registration, Evaluation, Authorization and Restriction of Chemicals (REACH)

The European Union Trading Directive resulting in European Emissions Trading Scheme

These laws and their associated regulations establish limits on emissions and standards for quality of air, water and solid waste discharges. They also generally require permits for new or modified operations. Many states and foreign countries where the Company operates also have or are in the process of developing similar statutes and regulations governing air and water as well as the characteristics and composition of refined products, which in some cases impose or could impose additional and more stringent requirements. Murphy is also subject to certain acts and regulations, including legal and administrative proceedings, governing remediation of wastes or oil spills from current and past operations, which include but may not be limited to leaks from pipelines, underground storage tanks and general environmental operations. Murphy is actively engaged in the legislative and regulatory process, both nationally and internationally, in response to climate change issues and environmental and health related matters.

Murphy s Health, Safety & Environmental (HSE) Committee, a standing committee of the Board of Directors, was created to oversee and monitor the Company s health, safety and environmental policies and practices. The Board has approved a worldwide health, safety and environmental (the HSE Policy), which is available on the Company s Web site. In addition to requiring that the Company comply with all applicable HSE laws and regulations, the HSE Policy includes a directive that the Company will continue to minimize the impact of its operations, products and services on the environment by implementing economically feasible projects that promote energy efficiency and use natural resources effectively.

CERCLA

CERCLA commonly referred to as the Superfund Act, and comparable state statutes, primarily address historic contamination and impose joint and several liability upon Potentially Responsible Parties (PRP), without regard to fault or the legality of the original act that contributed to the release of a hazardous substance into the environment. Cleanup of contaminated sites is the responsibility of the owners and operators of the sites that released, disposed, or arranged for the disposal of the hazardous substances found at the site. CERCLA requires reporting to the National Response Center for releases to the environment of substances defined as hazardous or extremely hazardous if the released quantities exceed an EPA established reportable level. CERCLA also authorizes the U.S. Environmental Protection Agency (EPA) and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible persons. In the course of ordinary operations, the Company generates waste that falls within CERCLA s definition of a hazardous substance. Murphy may be jointly and severally liable under CERCLA for all or part of the costs required to remediate sites at which such hazardous substances have been disposed of or released into the environment.

The EPA currently considers Murphy to be a PRP at one Superfund site. The Company has thus far been unable to ascertain any association with the Superfund site based on its research of the facts associated with the site, and the Company has notified the EPA accordingly. Based on currently available information, the Company believes that it has no responsibility at this Superfund site. The potential total cost to all parties to perform necessary remedial work at the site may be substantial. If proven to be responsible, the Company could be required to bear a pro rata share of costs attributable to nonparticipating PRPs or could be assigned additional responsibility for remediation at this site. The Company believes that its share of the ultimate costs to remediate this Superfund site will be immaterial and will not have a material adverse effect on net income, financial condition or liquidity in a future period. Murphy Oil Corporation has assigned its potential liability for one other Superfund site to Murphy USA Inc., and this company has accepted any potential responsibility for this site.

Waste

The Company currently owns or leases, and has in the past owned or leased, properties at which hazardous substances have been or are being handled. Although the Company has used operating and disposal practices that were standard in the industry at the time, hazardous substances may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes were not under Murphy s control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws Murphy could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. While some of these historical properties are in various stages of negotiation, investigation, and/or cleanup, Murphy is investigating the extent of any such liability and the availability of applicable defenses, and believe costs related to these sites will not have a material adverse affect on its net income, financial condition or liquidity in a future period. Although certain environmental expenditures may be recovered from other sources, no assurance can be given that future recoveries from these sources will occur. Therefore, the Company has not recorded a benefit for likely recoveries as of December 31, 2013.

RCRA and comparable state statutes govern the management and disposal of solid wastes, with the most stringent regulations applicable to treatment, storage or disposal of hazardous wastes. Murphy generates non-hazardous solid wastes that are subject to the requirements of RCRA and comparable state statutes. The Company s operating sites also incur costs to handle and dispose of hazardous waste and other chemical substances. The costs of disposing of these substances are expensed as incurred and are not expected to have a material adverse effect on net income, financial condition or liquidity in a future period. However, it is possible that additional wastes, which could include wastes currently generated during operations, will in the future be designated as hazardous wastes. Hazardous wastes are subject to more rigorous and costly disposal requirements than are non-hazardous wastes. Such changes in the regulations could result in additional capital expenditures and operating expenses.

Water

Under OPA90, owners and operators of tankers, owners and operators of onshore facilities and pipelines, and lessees or permittees of an area in which an offshore facility is located are liable for removal and cleanup costs of oil discharges into navigable waters of the United States. The Company is not aware of OPA90 claims made against Murphy.

Each Murphy offshore facility in the Gulf of Mexico has in place an Emergency Evacuation Plan (EEP) and all such facilities are covered by an Oil Spill Response Plan (OSRP). In the event of an explosion, personnel would be evacuated immediately in accordance with the EEP. The appropriate OSRP would be activated if needed. In the event of an oil spill or containment event, the appropriate OSRP and Containment Plan would be executed as needed. The EEP is approved by the U.S. Coast Guard (USCG) and the OSRP and Containment Plan are approved by the Bureau of Ocean Energy Management (BOEM). The Company also has comprehensive emergency and spill response plans for offshore facilities in international waters.

Murphy s OSRP utilizes a consortium of seasoned and well equipped contract service companies to provide response equipment and personnel. One company has been contracted to provide spill containment and recovery equipment, including skimmers, boom, and vessels such as fast response boats and high volume open sea skimmer barges. This company has hired other companies to store and maintain response equipment and provide certified tanks and barges. Murphy is a founding member of Marine Preservation Association, which provides access to Marine Spill Response Corporation assets to support marine spills in the Gulf of Mexico and other offshore areas. Additionally, Murphy has an agreement with another company to provide aerial dispersant spraying services, and has further contracted with another company to utilize their equipment for oil containment should a well blowout occur.

The Federal Water Pollution Control Act of 1972 (FWPCA) imposes restrictions and strict controls regarding the discharge of pollutants into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA imposes substantial potential liability for the costs of removal, remediation and damages. Murphy maintains wastewater discharge permits for its facilities where required pursuant to the FWPCA and comparable state laws. Murphy has also applied for all necessary permits to discharge storm water

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under such laws. The Company believes that compliance with existing permits and foreseeable new permit requirements will not have a material adverse effect on net income, financial condition or liquidity in a future period.

Murphy utilizes hydraulic fracturing technology for its exploration and production activities in the U.S. and Canada. Murphy is actively engaged in exploration and production in the Eagle Ford Shale play in South Texas. The State of Texas has adopted a law that requires oil and gas operators to publicly disclose to the Railroad Commission the chemicals and amount of water used in hydraulic fracturing of wells. The Provinces of British Columbia and Alberta have also issued regulations related to hydraulic fracturing activities under their jurisdictions. Murphy is in substantial compliance with these rules.

Air

Murphy s U.S. operations are subject to the Federal Clean Air Act and comparable state and local statutes. The Company believes that its operations are in substantial compliance with these statutes in all states in which it operates.

The European Union has adopted an Emissions Trading Scheme in response to the Kyoto Protocol in order to achieve reductions in greenhouse gas emissions. Murphy s refinery at Milford Haven, Wales, currently has the most exposure to these requirements and may require purchase of emission allowances to maintain compliance with environmental permit requirements. These environmental expenditures are expensed as incurred. In 2011, Murphy was notified by the Environment Agency (EA) that it failed to surrender proper emission allowances, which Murphy self-reported to the EA in 2010. The EA originally recommended a civil penalty of $1.7 million for this matter, however the matter has been resolved and no civil penalty was assessed or paid by the Company.

Climate Change

Currently, various national and international legislative and regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane and nitrous oxides) are in various phases of discussion or implementation. These include a promulgated EPA regulation, Mandatory Reporting of Greenhouse Gases for numerous industrial business segments, including offshore production operations, which became effective December 29, 2009. These were followed by a regulation requiring Mandatory Reporting of Greenhouse Gases for Petroleum and Natural Gas Systems, including onshore exploration and production facilities, which became effective December 31, 2010 and was revised December 23, 2011. During 2011, U.S. federal legislation (EPA s Greenhouse Gas Endangerment Finding, EPA s Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, Low Carbon Fuel Standards, etc.) and various state actions were proposed/finalized to develop statewide or regional programs, each of which have or could impose mandatory reductions and reporting of greenhouse gas emissions. Murphy believes it has met all of the EPA required reporting deadlines and strives to ensure accurate and consistent emissions data reporting. The impact of existing and pending climate change legislation, regulations, international treaties and accords could result in increased costs to the Company to (i) operate and maintain facilities; (ii) install new emission controls on facilities; and (iii) administer and manage any greenhouse gas emissions trading program. The physical impacts of climate change present potential risks for severe weather (floods, hurricanes, tornadoes, etc.) at its offshore platforms in the Gulf of Mexico and its onshore operations in the Eagle Ford Shale play in South Texas. Commensurate with this risk is the possibility of indirect financial and operational impacts to the Company from disruptions to the operations of major customers or suppliers caused by severe weather. The Company is unable to predict at this time how much the cost of compliance with any future legislation or regulation of greenhouse gas emissions, or the cost impact of natural catastrophic events resulting from climate change, if it occurs, will be in future periods.

Environmental Stewardship

The Company recognizes the importance of environmental stewardship as a core component of its mission as a responsible international energy company and has implemented sufficient disclosure controls and procedures to capture and process environmental, safety and climate-change related information. As a companion to Murphy s worldwide HSE Policy, the Company s Web site also contains a statement on climate change. Not only does this statement on climate change include Murphy s goal of reducing greenhouse gas emissions on an absolute basis while growing its upstream operations, the information on the Company s Web site describes actions already taken to move towards that goal. These efforts include incorporating climate change into the Company s planning processes, reducing emissions, pursuing new opportunities and engaging legislative and regulatory entities externally. In support of these efforts, worldwide greenhouse gas inventories have been conducted since 2001. Additionally, Murphy participates in the Massachusetts Institute of Technology (MIT) Joint Program on the Science and Policy of Global Change. The initiatives cited above demonstrate the Company s commitment regarding environmental issues, which are at the forefront of today s global public policy dialogue.

Other Matters

The Company is involved in personal injury and property damage claims, allegedly caused by exposure to or by the release or disposal of materials manufactured or used in its operations. Under Murphy s accounting policies, an environmental liability is recorded when such an obligation is probable and the cost can be reasonably estimated. If there is a range of reasonably estimated costs, the most likely amount will be recorded, or if no amount is most likely, the minimum of the range is used. Recorded liabilities are reviewed routinely. Actual cash expenditures often occur one or more years after a liability is recognized.

Safety Matters

The Company is subject to the requirements of the Federal Occupational Safety and Health Act (OSHA) and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that certain information be maintained about hazardous materials used or produced in Murphy s operations and that this information be provided to employees, state and local government authorities and citizens. The Company believes that its operations are in substantial compliance with OSHA requirements, including general industry standards, record-keeping requirements and monitoring of occupational exposure to regulated substances.

Other Matters

Impact of inflation General inflation was moderate during the last three years in most countries where the Company operates; however, the Company s revenues and capital and operating costs are influenced to a larger extent by specific price changes in the oil and gas and allied industries than by changes in general inflation. Crude oil and petroleum product prices generally reflect the balance between supply and demand, with crude oil prices being particularly sensitive to OPEC production levels and/or attitudes of traders concerning supply and demand in the near future. Natural gas prices are affected by supply and demand, which are often affected by the weather and by the fact that delivery of gas is generally restricted to specific geographic areas. Prices for oil field goods and services have generally risen (with certain of these price increases such as drilling rig day rates having been significant at times) during the last few years primarily driven by high demand for such goods and services in a strong oil price environment. As noted elsewhere, oil and natural gas prices have been extremely volatile over the last several years. Oil prices have been strong in the last few years, while North American natural gas prices have been weak due to oversupply of natural gas in this market. Oil prices in the current range of $90 per barrel and above generally lead to strong demand for oil field services. The prices for oil field goods and services generally rise in periods of higher oil prices and do not usually decline as significantly when oil and gas prices retreat. Should oil prices rise further in future periods, the Company anticipates that prices for certain oil field equipment and services could rise sharply. Due to the volatility of oil and natural gas prices, it is not possible to determine what effect these prices will have on the future cost of oil field goods and services.

Accounting changes and recent accounting pronouncements In December 2011, the FASB issued an accounting standards update that requires enhanced disclosures about financial instruments and derivative instruments that are either offset in the balance sheet or are subject to an enforceable master netting arrangement or similar agreement. The guidance was effective for all interim and annual periods beginning on or after January 1, 2013. These disclosures are presented in Note P to the consolidated financial statements.

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In February 2013, the FASB issued an accounting standards update that requires additional disclosures for reclassification adjustments from accumulated other comprehensive income (AOCI). These additional disclosures include changes in AOCI balances by component and significant items reclassified out of AOCI. These disclosures must be presented either on the face of the affected financial statement or in the notes to the financial statements. The disclosures were effective for Murphy Oil beginning in 2013 and are to be provided on a prospective basis. These disclosures are presented in Note O to the consolidated financial statements.

The United States Congress passed the Dodd-Frank Act (the Act) in 2010. As mandated by the Act, the U.S. Securities and Exchange Commission (SEC) issued rules regarding annual disclosures for purchases of conflict minerals and payments made to the U.S. Federal and all foreign governments by extractive industries, including oil and gas companies. Conflict minerals are defined as tin, tantalum, tungsten and gold which originate from the Democratic Republic of Congo or adjoining countries. For companies to whom the rule applies, the first annual report for conflict minerals must be filed by May 31, 2014 for the calendar year of 2013. Based on its assessment, the Company has determined that the rule does not currently apply to it and, therefore, it is not required to file an annual conflict minerals report.

On July 2, 2013, the United States District Court for the District of Columbia vacated the SEC s rules regarding reporting of payments made to the U.S. Federal and foreign governments. The D.C. Court found that the SEC misread the Act to mandate public disclosure of reports and that the denial of exemptions in the case of countries that prohibit public disclosures was improper. The Court remanded the matter to the SEC, which has indicated that it will restart the rulemaking process. The Company cannot predict how the SEC will alter its rules based on the Court s findings.

Significant accounting policies In preparing the Company s consolidated financial statements in accordance with U.S. generally accepted accounting principles, management must make a number of estimates and assumptions related to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Application of certain of the Company s accounting policies requires significant estimates. The most significant of these accounting policies and estimates are described below.

Proved oil and gas reserves Proved oil and gas reserves are defined by the SEC as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether a deterministic method or probabilistic method is used for the estimation. Proved developed oil and gas reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well, or through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Although the Company s engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. SEC rules require the Company to use an unweighted average of the oil and gas prices in effect at the beginning of each month of the year for determining quantities of proved reserves. These historical prices often do not approximate the average price that the Company expects to receive for its oil and natural gas production in the future. The Company often uses significantly different oil and natural gas price and reserve assumptions when making its own internal economic property evaluations. Estimated reserves are subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserves quantities. Reserves revisions inherently lead to adjustments of the Company s depreciation rates and the timing of settlement of asset retirement obligations. Downward reserves revisions can also lead to

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significant impairment expense. The Company cannot predict the type of oil and natural gas reserves revisions that will be required in future periods. The Company s proved reserves of oil and natural gas are presented on pages F-52 to F-55 of this Form 10-K report. Murphy s estimations for proved reserves were generated through the integration of available geoscience, engineering, and economic data, and commercially available technologies, to establish reasonable certainty of economic producibility. As defined by the SEC, reasonable certainty of proved reserves describes a high-degree of confidence that the quantities will be recovered. In estimating proved reserves, Murphy uses familiar industry-accepted methods for subsurface evaluations, including performance, volumetric, and analogue based studies. Where appropriate, Murphy includes reliable geologic and engineering technology to estimate proved reserves. Reliable geologic and engineering technology is a method or combination of methods that are field-tested and have demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. This integrated approach increases the quality of and confidence in Murphy s proved reserves estimates, and was utilized in certain undrilled acreage at distances greater than the directly offsetting development spacing areas, and in certain reservoirs developed with the application of improved recovery techniques. Murphy utilized a combination of 3D seismic interpretation, core analysis, wellbore log measurements, well test data, historic production and pressure data, and commercially available seismic processing and numerical reservoir simulation programs. Reservoir parameters from analogous reservoirs were used to strengthen the reserves estimates when available.

Oil proved reserves revisions

In 2013, a positive proved oil reserves revision in the U.S. was attributable to better well performance in the Eagle Ford Shale, conversion of proved wet gas reserves to proved oil reserves that include natural gas liquids, and minor adds to several fields in the Gulf of Mexico. The 2013 positive revision for conventional oil in Canada was caused by well performance at the Hibernia and Terra Nova fields. Synthetic oil revisions were positive in 2013 primarily due to revised cost recovery factors for bitumen extraction following renegotiated royalty terms with the government. Positive revisions in Malaysia in 2013 were principally attributable to well performance at Kikeh.

In 2012, proved oil reserves in the U.S. had positive revisions which arose from improved well performance in the Eagle Ford Shale area and at the Medusa field in the Gulf of Mexico. Negative conventional proved oil reserves revisions in Canada in 2012 occurred due to a lower recovery assessment for certain wells drilled in the Seal heavy oil area in Western Canada. Negative synthetic oil reserves revisions in 2012 at Syncrude were related to a change in entitlement that increased government royalties based on a recent projection for future operating and capital spending. The negative proved oil reserves revision in Republic of the Congo was associated with poor well performance, a well that prematurely went off production, and generally uneconomic remaining future production levels.

In 2011, positive proved oil reserves revisions in the U.S. were primarily associated with better production at the Medusa field in the Gulf of Mexico. Positive 2011 revisions for oil reserves of conventional operations in Canada were mostly attributable to better well performance at the Hibernia field, offshore Eastern Canada. Synthetic oil operations had positive reserves revisions in 2011 due to a change in royalty rate. Positive oil reserves revisions in 2011 in Malaysia were primarily attributable to better production performance at the Kikeh field. Positive oil reserves revisions in the U.K. in 2011 were associated with the Schiehallion field which is being redeveloped by its owners. The negative revision in oil reserves in Republic of the Congo in 2011 was attributable to poor production results for wells in the Azurite field.

Natural gas proved reserves revisions

In 2013, proved natural gas reserves in the U.S. had negative revisions primarily due to conversion of proved wet gas reserves to proved residual gas reserves. Positive revisions in Canada in 2013 were mostly

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attributable to better well performance in the Tupper West area. Malaysia had 2013 positive gas revisions principally due to better well performance at gas fields offshore Sarawak. The Kikeh field also had positive revisions due to better overall well performance.

During 2012, proved natural gas reserves in the U.S. had positive revisions due to improved well performance at several fields in the Gulf of Mexico, plus better well performance in the Eagle Ford Shale area. Proved natural gas reserves in Canada were revised downward in 2012 due to weaker average natural gas prices in the current year that adversely affected certain areas in the Montney formation of Western Canada. Proved natural gas reserves in Malaysia in 2012 had positive revisions due to better well performance and favorable entitlement effects for gas operations offshore Sarawak.

In 2011, proved natural gas reserves in the U.S. had negative revisions due to well performance being less than expected in early wells drilled in the gas-prone regions of the Eagle Ford Shale in South Texas. Positive gas reserves revisions in Canada in 2011 were primarily at the Tupper and Tupper West areas based on better than anticipated well performance. Negative gas reserves revisions in Malaysia in 2011 were primarily due to higher sales prices which effectively reduced the entitlement percentage for future production at the Sarawak gas fields. Negative gas reserves revisions in the U.K. in 2011 were essentially caused by revised estimate of gas-cap volumes at the Mungo/Monan field.

Successful efforts accounting The Company utilizes the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration wells are expensed and can have a significant effect on net income. Successful exploration drilling costs and all development capital expenditures are capitalized and systematically charged to expense using the units of production method based on proved developed oil and natural gas reserves as estimated by the Company s engineers. In some cases, a determination of whether a drilled well has found proved reserves cannot be made immediately. This is generally due to the need for a major capital expenditure to produce and/or evacuate the hydrocarbon(s) found. The determination of whether to make such a capital expenditure is, in turn, usually dependent on whether additional exploratory wells find a sufficient quantity of additional reserves. Under current accounting rules, the Company holds well costs in Property, Plant and Equipment in the Consolidated Balance Sheet when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Based on the time required to complete further exploration and appraisal drilling in areas where hydrocarbons have been found but proved reserves have not been booked, dry hole expense may be recorded one or more years after the original drilling costs are incurred. In 2013, two wells offshore Sarawak drilled in 2005 and 2006 were expensed when the Company decided not to move forward with development plans for this area. In 2012, a well in the MPN block offshore Republic of the Congo was expensed. This well had been drilled in late 2010 and was held until another well nearby could be drilled; the nearby well was unsuccessfully drilled in 2012. Also in 2012, two wells drilled offshore Sarawak in 2008 were expensed following a decision to halt development plans for these wells. Additionally in 2012, a well drilled in the Gulf of Mexico in 2010 was expensed following the owners decision not to develop the well. In 2011, a dry hole was recorded for a well drilled in Republic of the Congo in 2009. A significant reduction in proved oil reserves at the Azurite field in the same MPS block during 2011 reduced the likelihood of this well being produced in future years.

Impairment of long-lived assets The Company continually monitors its long-lived assets recorded in Property, Plant and Equipment and Goodwill in the Consolidated Balance Sheet to make sure that they are fairly presented. The Company must evaluate its properties for potential impairment when circumstances indicate that the carrying value of an asset may not be recoverable from future cash flows. Goodwill is evaluated for impairment at least annually. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the amount of oil and natural gas that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, future

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capital and abandonment costs, future margins on refined products, and future inflation levels. The need to test a long-lived asset for impairment can be based on several factors, including but not limited to a significant reduction in sales prices for oil and/or natural gas, unfavorable revisions of oil or natural gas reserves, expected deterioration of future margins for refining and/or marketing operations, or other changes to contracts, environmental regulations or tax laws. All of these same factors must be considered when evaluating a property s carrying value for possible impairment. In making its impairment assessments involving exploration and production property and equipment, the Company must make a number of projections involving future oil and natural gas sales prices, future production volumes, and future capital and operating costs. Due to the volatility of world oil and gas markets, the actual sales prices for oil and natural gas have often been quite different from the Company s projections. Estimates of future oil and gas production and sales volumes are based on a combination of proved and risked probable and possible reserves. Although the estimation of reserves and future production is uncertain, the Company believes that its estimates are reasonable; however, there have been cases where actual production volumes were higher or lower than projected and the timing was different than the original projection. The Company adjusts reserves and production estimates as new information becomes available. The Company generally projects future costs by using historical costs adjusted for both assumed long-term inflation rates and known or expected changes in future operations. Although the projected future costs are considered to be reasonable, at times, costs have been higher or lower than originally estimated. In assessing potential impairment involving refining and marketing assets, the Company evaluates its properties when circumstances indicate that the carrying value of an asset may not be recoverable from future cash flows. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events, which include projections of future margins, future capital expenditures and future operating expenses. Future marketing or operating decisions, such as closing or selling certain assets, and future regulatory or tax changes could also impact the Company s conclusion about potential asset impairment. Murphy recorded impairment expense of $21.6 million in 2013 related to the sale of Kainai properties in Western Canada at less than carrying value. The Company recorded a $73.0 million writedown in 2013 for discontinued U.K. refining and marketing operations based on an assessment of the fair value of these assets based on the status of the ongoing sale process. The Company recorded impairment expense in 2012 of $200.0 million for the Azurite field, offshore Republic of the Congo, and $61.0 million in discontinued operations for the Hereford, Texas ethanol production facility. The Congo impairment was necessitated by removal of all proved oil reserves at Azurite following an unsuccessful redrill of a well; this result led to uneconomic future oil production operations for the field. The Hereford ethanol plant impairment was based on an expectation of continued weak future ethanol margins at the production facility owned by the Company s U.S. downstream subsidiary that was spun-off in 2013. The Hereford impairment was determined using available years of futures prices for corn and ethanol, plus a terminal value based on a reasonable multiple of the final year s cash flow. Impairment expense of $368.6 million was recognized in 2011 to reduce the carrying value of the Azurite oil field, offshore Republic of the Congo, to fair value. The expense was necessitated by a significant year-end 2011 reduction of proved oil reserves at this field which was caused by poor well performance. Based on an evaluation of expected future cash flows from properties at year-end 2013, the Company does not believe it had any other significant properties with carrying values that were impaired at that date. The expected future sales prices for crude oil and natural gas used in the evaluation were based on quoted future prices for the respective production periods. These quoted prices are often based on an expectation of continued strong oil prices, and normally stronger North American natural gas prices in the future compared to the existing spot prices at the time of assessment. If quoted prices for future years had been lower, the smaller projected cash flows for properties could have led to significant impairment charges being recorded for certain properties in 2013. In addition, one or a combination of other factors such as lower future production volumes, higher future costs, lower future margins on refining and marketing, or the actions of government authorities could lead to impairment expenses in future periods. Based on these unknown future factors as described herein, the Company cannot predict the amount or timing of impairment expenses that may be recorded in the future.

Income taxes The Company is subject to income and other similar taxes in all areas in which it operates. When recording income tax expense, certain estimates are required because: (a) income tax returns are generally filed months after the close of its annual accounting period; (b) tax returns are subject to audit by taxing authorities and audits can often take years to complete and settle; and (c) future events often impact the timing of when income tax expenses and benefits are recognized by the Company. The Company has deferred tax assets mostly relating to basis differences for property, equipment and inventories, and dismantlements and retirement benefit plan liabilities. The Company routinely evaluates all deferred tax assets to determine the likelihood of their realization. A valuation allowance has been recognized for deferred tax assets related to basis differences for Blocks H and PM 311/312 in Malaysia, for exploration licenses in certain areas, the largest of which are Australia, Indonesia and Brunei, and for certain basis differences in the U.K. due to management s belief that these assets cannot be deemed to be realizable with any degree of confidence at this time. In 2013, the Company recognized U.S. income tax benefits of $133.5 million related to tax deductions associated with investments in upstream operations in Republic of the Congo and Kurdistan. The Company is exiting operations in these countries. During 2012, the Company recognized U.S. tax benefits related to upstream activities in Republic of the Congo and Suriname that totaled $108.3 million. These 2012 U.S. benefits arose due to tax deductions for worthless stock investments in these countries. The Company occasionally is challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in its various income tax returns. Although the Company believes that it has adequate accruals for matters not resolved with various taxing authorities, gains or losses could occur in future years from changes in estimates or resolution of outstanding matters.

Accounting for retirement and postretirement benefit plans Murphy Oil and certain of its subsidiaries maintain defined benefit retirement plans covering most full-time employees. Effective with the spin-off of the Company s former U.S. retail marketing operation (MUSA) on August 30, 2013, significant modifications were made to the U.S. defined benefit pension plan. Certain employees benefits under the U.S. plan were frozen at that time. No further benefit service will accrue for the affected employees, however, the plan will recognize future compensation increases after the spin-off. In addition, all previously unvested benefits became fully vested at the spin-off date. For those affected active employees of the Company, additional U.S. retirement plan benefits will accrue in future periods under a cash balance formula. Upon the spin-off of MUSA, the Company retained all vested pension defined benefit and other postretirement benefit obligations associated with current and former employees of this business. No additional benefit will accrue for employees of MUSA under the Company s retirement plan after the separation date. The Company also sponsors health care and life insurance benefit plans covering most retired U.S. employees. The expense associated with these plans is determined by management based on a number of assumptions and with consultation assistance from qualified third-party actuaries. The most important of these assumptions for the retirement plans involve the discount rate used to measure future plan obligations and the expected long-term rate of return on plan assets. For the retiree medical and insurance plans, the most important assumptions are the discount rate for future plan obligations and the health care cost trend rate. Discount rates are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate which is the basis for selecting the discount rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Anticipated health care cost trend rates are determined based on prior experience of the Company and an assessment of near-term and long-term trends for medical and drug costs.

Based on bond yields at December 31, 2013, the Company has used a discount rate of 4.91% at year-end 2013 for the primary U.S. plans. The year-end 2013 discount rate is 0.73% higher than a year earlier; this higher rate reduced the Company s recorded liabilities for retirement plans compared to a year ago. Although the Company presently assumes a return on plan assets of 6.50% for the primary U.S. plan, it periodically reconsiders the appropriateness of this and other key assumptions. The smoothing effect of current accounting regulations tends to buffer the current year s retirement plan expenses from wide swings in liabilities and asset valuations. The Company s retirement and postretirement plan expenses are expected be reduced in 2014 compared to 2013 based on the changes in benefits following the separation of MUSA. However, cash contributions are anticipated to be slightly higher in 2014 particularly associated with foreign retirement plans. In 2013, the Company paid $46.7 million into various retirement plans and $3.5 million into postretirement plans. In 2014, the Company is expecting to fund payments of approximately $49.1 million into various retirement plans and $5.9 million for postretirement plans. The Company could be required to make additional and more significant funding payments to retirement plans in future years. Future required payments and the amount of liabilities recorded on the balance sheet associated with the plans could be unfavorably affected if the discount rate declines, the actual return on plan assets falls below the assumed return, or the health care cost trend rate increase is higher than expected. Although Congress passed the Moving Ahead for Progress in the 21st Century Act, which permits certain companies to reduce retirement plan contributions in the near term, this Act does not reduce the Company s overall funding requirements in the long-term. As described above, the Company s retirement and postretirement expenses are sensitive to certain assumptions, primarily related to discount rates and assumed return on plan assets. A 0.5% decline in the discount rate would increase 2014 annual retirement and postretirement expenses by $6.4 million and $0.6 million, respectively, and a 0.5% decline in the assumed rate of return on plan assets would increase 2014 retirement expense by $2.7 million.

Legal, environmental and other contingent matters A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and other contingent matters. In addition, the Company often must estimate the amount of such losses. In many cases, management s judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. The Company s management closely monitors known and potential legal, environmental and other contingent matters, and makes its best estimate of the amount of losses and when they should be recorded based on information available to the Company.

Contractual obligations and guarantees The Company is obligated to make future cash payments under borrowing arrangements, operating leases, purchase obligations primarily associated with existing capital expenditure commitments, and other long-term liabilities. In addition, the Company expects to extend certain operating leases beyond the minimum contractual period. Total payments due after 2013 under such contractual obligations and arrangements are shown below.

	Amount of Obligations				
(Millions of dollars)	Total	2014	2015-2016	2017-2018	After 2018
Total debt including current maturities	$ 2,962.8	26.2	36.7	940.5	1,959.4
Operating and other lease obligations	1,393.9	259.9	320.8	231.1	582.1
Purchase obligations	3,337.1	2,384.6	876.6	37.3	38.6
Other long-term liabilities, including debt interest	2,394.6	230.5	255.0	275.1	1,634.0
Total	$ 10,088.4	2,901.2	1,489.1	1,484.0	4,214.1

The Company has entered into agreements to lease production facilities for various producing oil fields. In addition, the Company has other arrangements that call for future payments as described in the following section. The Company s share of the contractual obligations under these leases and other arrangements has been included in the table above.

In 2013, the Company entered into a 25-year lease for a semi-floating production system at the Kakap-Gumusut field offshore Sabah, Malaysia. The Company has included the required lease obligations for this production system in the contractual obligation table above.

In the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide letters of credit that may be drawn upon if the Company fails to perform under those contracts. Total outstanding letters of credit were $129.9 million as of December 31, 2013, and all of these letters of credit expire in 2014.

Material off-balance sheet arrangements The Company occasionally utilizes off-balance sheet arrangements for operational or funding purposes. The most significant of these arrangements at year-end 2013 included operating leases of floating, production, storage and offloading vessels (FPSO) for the Kikeh and Azurite oil fields, operating leases for production facilities at the Thunder Hawk and West Patricia fields and for certain land and/or fueling stations in the U.K., drilling contracts for onshore and offshore rigs in various countries, and oil and/or natural gas transportation contracts in the U.S. and Western Canada. The leases call for future monthly net lease payments through 2014 at Thunder Hawk, through 2016 at West Patricia and Azurite and through 2023 at Kikeh. The U.K. fueling stations require monthly payments mostly over the next 20 years. The U.S. and Western Canada transportation contracts require minimum monthly payments through 2023. Future required minimum annual payments under these arrangements are included in the contractual obligation table on page 52.

Outlook

Prices for the Company s primary products are often quite volatile. The price for crude oil is primarily affected by the level of demand for energy. Anticipated future variances between the predicted demand for crude oil and the projected available supply can lead to significant movement in the price of crude oil. In January 2014, West Texas Intermediate crude oil traded in a band between $91 and $99 per barrel and averaged about $95 for the full month. NYMEX natural gas traded in a band of $3.95 to $5.50 per MMBTU, with an average of $4.55 during this same time. Natural gas prices increased further in February 2014. U.K. refining margins remained depressed in January 2014. The Company continually monitors the prices for its main products and often alters its operations and spending based on these prices.

The Company s capital expenditure budget for 2014 was prepared during the fall of 2013 and based on this budget capital expenditures in 2014 are expected to be below 2013 levels by about 5% for continuing operations. Since the budget was approved by the Company s Board of Directors, crude oil and North American natural gas sales prices have generally been above the levels assumed in the 2014 budget. Capital expenditures in 2014 are projected to total approximately $3.8 billion. Geographically, E&P capital in the 2014 budget is spread approximately as follows: 51% for the United States, 28% for Malaysia, 13% for Canada and 8% for all other areas. Spending in the U.S. is primarily associated with development and exploration programs in the Eagle Ford Shale area of South Texas. In Malaysia, the majority of the spending is for continued development of the Kikeh, Kakap-Gumusut and Siakap North-Petai fields in Block K and oil development projects offshore Sarawak in Blocks SK 309 and SK 311. Canadian spending is fairly evenly distributed between development of the Seal heavy oil area, Syncrude, East Coast offshore development and Western Canada natural gas operations. Capital and other expenditures will be routinely reviewed during 2014 and planned capital expenditures may be adjusted to reflect differences between budgeted and actual cash flow during the year. Capital expenditures may also be affected by asset purchases, which often are not anticipated at the time the Budget is prepared.

The Company will primarily fund its capital program in 2014 using operating cash flow, but will supplement funding where necessary using borrowings under available credit facilities. The Company s 2014 budget calls for borrowings of long-term debt during the year to fund a portion of the capital program. If oil and/or natural gas prices weaken, actual cash flow generated from operations could be reduced such that higher than anticipated borrowings might be required during the year to maintain funding of the Company s ongoing development projects. Additionally, the 2014 budget assumes further share repurchases under the previously announced share buyback program of up to $1.0 billion. The level of these share repurchases is expected to influence the amount of borrowings under credit facilities during 2014. In February 2014, the Company announced an additional $250 million repurchase of its Common stock.

The Company currently expects production in 2014 to average between 235,000 and 240,000 barrels of oil equivalent per day, a 14% to 17% increase compared to 2013. A key assumption in projecting the level of 2014 Company production is the anticipated ramp up of crude oil and natural gas production in the Eagle Ford Shale area of South Texas, where a major drilling and completion operation is ongoing with eight rigs in use. Another key factor in meeting 2014 production targets is the rate of decline of natural gas wells at the Tupper area in Western Canada. The Company significantly reduced development drilling operations in this area in 2012 and

2013 due to depressed prices for Canadian natural gas production. Due to well declines following a period of voluntary drilling cut backs, natural gas production in the Tupper area will be lower in 2014 than the prior year. Other key assumptions necessary to achieve the anticipated 2014 production levels include a timely and successful start-up of the Dalmatian field in the Gulf of Mexico, full field production at the Kakap-Gumusut field, as well as continued reliability of production at significant operations such as Kikeh, Syncrude, Hibernia and Terra Nova and the continued demand for natural gas from our offshore Malaysia fields.

Through February 25, 2014, the Company has entered into derivative or forward delivery contracts to manage risk associated with certain future oil and natural gas sales prices as well as Malaysian foreign currency-based tax payments as follows:

Commodities	Contract or Location	Dates	Average Volumes per Day	Average Prices
U.S. Oil	West Texas Intermediate	Jan. Feb. 2014	20,000 bbls/d	$98.47 per bbl.
		Mar. 2014	33,000 bbls/d	$98.03 per bbl.
		Apr. Jun. 2014	24,000 bbls/d	$96.41 per bbl.
		Jul. Sep. 2014	20,000 bbls/d	$94.32 per bbl.
		Oct. Dec. 2014	12,000 bbls/d	$91.72 per bbl.
Canadian Heavy Oil	Western Canadian Sour	Feb. Mar. 2014	4,000 bbls/d	$48.89 per bbl.
		Apr. Jun. 2014	2,000 bbls/d	$55.01 per bbl.
Canadian Natural Gas	AECO	Jan. 2014	80 mmcf/d	C$3.98 per mcf
		Feb. Dec. 2014	110 mmcf/d	C$4.04 per mcf
		Jan. Dec. 2015	38 mmcf/d	C$4.05 per mcf

Foreign Currency	Dates	U.S. Dollars	Malaysian Ringgits
Currency Financial Swap	April 2014	$44,458,000	MYR149,000,000
	May 2014	44,698,000	MYR149,000,000
	June 2014	44,339,000	MYR149,000,000

The Company s 2014 budget anticipates an increase for overall hydrocarbon extraction costs by about $4.00 on a barrel of oil equivalent basis. Production expense in 2014 is projected to decline on a per barrel basis due to expected continued cost improvements in the Eagle Ford Shale and no further production at the Azurite field in Republic of the Congo. The overall per-unit depreciation rate for oil and gas operations is anticipated to rise in 2014 due to ongoing capital development costs at Kikeh, the Seal heavy oil area and Terra Nova, and start-up of new fields, such as Dalmatian and Siakap North-Petai, which are early in the proved reserves migration process. Additionally, there is an unfavorable effect on the overall depreciation rate in 2014 from a lower mix of natural gas production in the Tupper area of Canada and the full field start-up of the Kakap-Gumusut field.

The Company has announced that it plans to exit the U.K. refining and marketing business. The sale process for this U.K. R&M business continues to progress in early 2014.

Following separation of the U.S. downstream subsidiary from Murphy Oil Corporation during 2013 and with the desired sale of the U.K. downstream business, the Company is expected to be fundamentally different. The Company will be a fully independent oil and gas company. The reduction in revenue, coupled with the loss of downstream earnings and a change in overall diversification could impact its credit rating, and could, although not expected to, impact its ability to repay long-term debt obligations when due.

Forward-Looking Statements

This Form 10-K contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. These statements, which express management s current views concerning future events or results, are subject to inherent risks and uncertainties. Factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements include, but are not limited to, the volatility and level of crude oil and natural gas prices, the level and success rate of our exploration programs, our ability to maintain production rates and replace reserves, customer demand for our products, adverse foreign exchange movements, political and regulatory instability, and uncontrollable natural hazards. Factors that could cause the forecasted sale of the Company s U.K. downstream business, as discussed in this Form 10-K, not to occur include, but are not limited to, a failure to obtain necessary regulatory approvals, a deterioration in the business or prospects of Murphy or its U.K. downstream subsidiary, adverse developments in Murphy or its U.K. downstream subsidiary s markets, adverse developments in the U.S. or global capital markets, credit markets or economies generally, and a failure to execute a sale of these U.K. operations on acceptable terms. For further discussion of risk factors, see Item 1A. Risk Factors, which begins on page 14 of this Annual Report on Form 10-K. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to market risks associated with interest rates, prices of crude oil, natural gas and petroleum products, and foreign currency exchange rates. Murphy uses derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions.

As described in Note K, there were short-term derivative foreign exchange contracts in place at December 31, 2013 to hedge the value of U.S. dollar based receivables against the Canadian dollar. A 10% strengthening of the U.S. dollar against the Canadian dollar would have increased the recorded net liability associated with these contracts by approximately $2.9 million, while a 10% weakening of the U.S. dollar would have reduced the recorded net liability by approximately $3.6 million. Changes in the fair value of these derivative contracts generally offset the financial statement impact of an equivalent volume of foreign currency exposures associated with other assets and/or liabilities.

There were also commodity derivative contracts in place at December 31, 2013 to hedge the sales price of certain Eagle Ford Shale oil production in 2014. A 10% increase in the respective benchmark price of these commodities would have reduced the recorded net asset associated with these derivative contracts by approximately $41.5 million, while a 10% decrease would have increased the recorded net asset by a similar amount.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages F-1 through F-61, which follow page 61 of this Form 10-K report.

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

None

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Item 9A. CONTROLS AND PROCEDURES

Under the direction of its principal executive officer and principal financial officer, controls and procedures have been established by Murphy to ensure that material information relating to the Company and its consolidated subsidiaries is made known to the officers who certify the Company s financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation, with the participation of the Company s management, as of December 31, 2013, the principal executive officer and principal financial officer of Murphy Oil Corporation have concluded that the Company s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective to ensure that the information required to be disclosed by Murphy Oil Corporation in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Murphy s management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Management has conducted an evaluation of the effectiveness of the Company s internal control over financial reporting based on the criteria set forth in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2013. Management s report is included on page F-1 of this Form 10-K report. KPMG LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2013 and their report is included on page F-3 of this Form 10-K report.

There were no changes in the Company s internal controls over financial reporting that occurred during the fourth quarter of 2013 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Item 9B. OTHER INFORMATION

None

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PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Certain information regarding executive officers of the Company is included on pages 20 and 21 of this Form 10-K report. Other information required by this item is incorporated by reference to the Registrant s definitive Proxy Statement for the Annual Meeting of Stockholders on May 14, 2014 under the captions Election of Directors and Committees.

Murphy Oil has adopted a Code of Ethical Conduct for Executive Management, which can be found under the Corporate Governance and Responsibility tab at www.murphyoilcorp.com. Stockholders may also obtain free of charge a copy of the Code of Ethical Conduct for Executive Management by writing to the Company s Secretary at P.O. Box 7000, El Dorado, AR 71731-7000. Any future amendments to or waivers of the Company s Code of Ethical Conduct for Executive Management will be posted on the Company s Web site.

Item 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to Murphy s definitive Proxy Statement for the Annual Meeting of Stockholders on May 14, 2014 under the captions Compensation Discussion and Analysis and Compensation of Directors and in various compensation schedules.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this item is incorporated by reference to Murphy s definitive Proxy Statement for the Annual Meeting of Stockholders on May 14, 2014 under the captions Security Ownership of Certain Beneficial Owners, Security Ownership of Management, and Equity Compensation Plan Information.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to Murphy s definitive Proxy Statement for the Annual Meeting of Stockholders on May 14, 2014 under the caption Election of Directors.

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by this item is incorporated by reference to Murphy s definitive Proxy Statement for the Annual Meeting of Stockholders on May 14, 2014 under the caption Audit Committee Report.

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PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements The consolidated financial statements of Murphy Oil Corporation and consolidated subsidiaries are located or begin on the pages of this Form 10-K report as indicated below.

2. Financial Statement Schedules

All other financial statement schedules are omitted because either they are not applicable or the required information is included in the consolidated financial statements or notes thereto.

3. **Exhibits** The following is an index of exhibits that are hereby filed as indicated by asterisk (*), that are considered furnished rather than filed, or that are incorporated by reference. Exhibits other than those listed have been omitted since they either are not required or are not applicable.

Exhibit No.		Incorporated by Reference to
2.1	Asset Purchase Agreement between Calumet Specialty Products Partners, L.P. and Murphy Oil Corporation covering the Superior, Wisconsin refinery	Exhibit 2.1 of Murphy s Form 10-Q report filed November 4, 2011
2.2	Asset Purchase Agreement between Valero Refining-Meraux LLC and Murphy Oil Corporation covering the Meraux, Louisiana refinery	Exhibit 2.2 of Murphy s Form 10-Q report filed November 4, 2011
2.3	Separation and Distribution Agreement, dated August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 2.1 of Murphy s Form 8-K report filed September 5, 2013
3.1	Certificate of Incorporation of Murphy Oil Corporation as amended, effective May 11, 2005	Exhibit 3.1 of Murphy s Form 10-K report filed February 28, 2011
3.2	By-Laws of Murphy Oil Corporation as amended effective August 7, 2013	Exhibit 3.1 of Murphy s Form 8-K report filed August 9, 2013

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Exhibit No.		Incorporated by Reference to
4	Instruments Defining the Rights of Security Holders. Murphy is party to other long-term debt instruments in addition to those in Exhibits 4.1 to 4.3, none of which authorizes securities exceeding 10% of the total consolidated assets of Murphy and its subsidiaries. Pursuant to Regulation S-K, item 601(b), paragraph 4(iii)(A), Murphy agrees to furnish a copy of each such instrument to the Securities and Exchange Commission upon request.	
4.1	Form of Indenture and Form of Supplemental Indenture between Murphy Oil Corporation and SunTrust Bank as Trustee	Exhibit 4.2 of Murphy s Form 10-K report for the year ended December 31, 2009
4.2	Form of Indenture and First Supplemental Indenture between Murphy Oil Corporation and U.S. Bank National Association, as Trustee	Exhibits 4.1 and 4.2 of Murphy s Form 8-K report filed May 18, 2012
4.3	Second Supplemental Indenture between Murphy Oil Corporation and U.S. Bank National Association, as Trustee	Exhibit 4.1 of Murphy s Form 8-K report filed November 30, 2012
10.1	2007 Long-Term Incentive Plan	Exhibit 10.1 of Murphy s Form 8-K report filed April 24, 2007
10.2	2012 Long-Term Incentive Plan	Exhibit A of Murphy s definitive proxy statement (Definitive 14A) dated March 29, 2012
10.3	Employee Stock Purchase Plan as amended May 9, 2007	Exhibit 10.3 of Murphy s Form 10-K report for the year ended December 31, 2012
10.4	2008 Stock Plan for Non-Employee Directors, as approved by shareholders on May 14, 2008	Form S-8 report filed February 5, 2009
10.5	2013 Stock Plan for Non-Employee Directors	Exhibit A of Murphy s definitive proxy statement (Definitive 14A) dated March 22, 2013
10.6	Letter Agreement dated as of June 20, 2012 between the Company and David M. Wood	Exhibit 10.1 of Murphy s Form 8-K report filed June 21, 2012
10.7	Tax Matters Agreement, dated August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.1 of Murphy s Form 8-K report filed September 5, 2013
10.8	Transition Services Agreement, dated August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.2 of Murphy s Form 8-K report filed September 5, 2013
10.9	Employee Matters Agreement, dated August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.3 of Murphy s Form 8-K report filed September 5, 2013
10.10	Trademark License Agreement, dated August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.4 of Murphy s Form 8-K report filed September 5, 2013

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Exhibit No.		Incorporated by Reference to
*12	Computation of Ratio of Earnings to Fixed Charges	
*13	2013 Annual Report to Security Holders	
*21	Subsidiaries of the Registrant	
*23	Consent of Independent Registered Public Accounting Firm	
*31.1	Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
*31.2	Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
*32	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	
*99.1	Form of employee stock option	
99.2	Form of performance-based employee restricted stock unit grant agreement	Exhibit 99.2 of Murphy s Form 10-K report for the year ended December 31, 2008
99.3	Form of employee time-based restricted stock unit grant agreement	Exhibit 99.1 of Murphy s Form 10-Q report filed November 6, 2013
99.4	Form of non-employee director stock option	Exhibit 99.3 of Murphy s Form 10-K report for the year ended December 31, 2010
99.5	Form of non-employee director restricted stock unit award	Exhibit 99.5 of Murphy s Form 10-K report for the year ended December 31, 2008
99.6	Form of non-employee director restricted stock unit award	Exhibit 99.2 of Murphy s Form 10-Q report filed November 6, 2013
99.7	Form of phantom unit award	Exhibit 99.1 of Murphy s Form 10-Q report filed November 6, 2012
99.8	Form of stock appreciation right (SAR)	Exhibit 99.6 of Murphy s Form 10-K report for the year ended December 31, 2012
99.9	Form of performance-based restricted stock unit-cash grant agreement	Exhibit 99.7 of Murphy s Form 10-K report for the year ended December 31, 2012
99.10	Form of performance-based units grant agreement	Exhibit 99.8 of Murphy s Form 10-K report for the year ended December 31, 2012
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema Document	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document	
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document	
101.PRE		

XBRL Taxonomy Extension Presentation
Linkbase

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SIGNATURES

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

MURPHY OIL CORPORATION

By	/s/ ROGER W. JENKINS Roger W. Jenkins, President	Date:	February 28, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 28, 2014 by the following persons on behalf of the registrant and in the capacities indicated.

/s/ CLAIBORNE P. DEMING Claiborne P. Deming, Chairman and Director	/s/ R. MADISON MURPHY R. Madison Murphy, Director
/s/ ROGER W. JENKINS Roger W. Jenkins, President and Chief Executive Officer and Director (Principal Executive Officer)	/s/ JEFFREY W. NOLAN Jeffrey W. Nolan, Director
/s/ FRANK W. BLUE Frank W. Blue, Director	/s/ NEAL E. SCHMALE Neal E. Schmale, Director
/s/ T. JAY COLLINS T. Jay Collins, Director	/s/ DAVID J. H. SMITH David J. H. Smith, Director
/s/ STEVEN A. COSSÉ Steven A. Cossé, Director	/s/ CAROLINE G. THEUS Caroline G. Theus, Director
/s/ ROBERT A. HERMES Robert A. Hermes, Director	/s/ KEVIN G. FITZGERALD Kevin G. Fitzgerald, Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ JAMES V. KELLEY James V. Kelley, Director	/s/ JOHN W. ECKART John W. Eckart Senior Vice President and Controller (Principal Accounting Officer)
/s/ WALENTIN MIROSH Walentin Mirosh, Director	

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REPORT OF MANAGEMENT CONSOLIDATED FINANCIAL STATEMENTS

The management of Murphy Oil Corporation is responsible for the preparation and integrity of the accompanying consolidated financial statements and other financial data. The statements were prepared in conformity with U.S. generally accepted accounting principles appropriate in the circumstances and include some amounts based on informed estimates and judgments, with consideration given to materiality.

An independent registered public accounting firm, KPMG LLP, has audited the Company s consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board and provides an objective, independent opinion about the Company s consolidated financial statements. The Audit Committee of the Board of Directors appoints the independent registered public accounting firm; ratification of the appointment is solicited annually from the shareholders. KPMG LLP s opinion covering the Company s consolidated financial statements can be found on page F-2.

The Board of Directors appoints an Audit Committee annually to implement and to support the Board s oversight function of the Company s financial reporting, accounting policies, internal controls and independent registered public accounting firm. This Committee is composed solely of directors who are not employees of the Company. The Committee meets routinely with representatives of management, the Company s audit staff and the independent registered public accounting firm to review and discuss the adequacy and effectiveness of the Company s internal controls, the quality and clarity of its financial reporting, the scope and results of independent and internal audits, and to fulfill other responsibilities included in the Committee s Charter. The independent registered public accounting firm and the Company s audit staff have unrestricted access to the Committee, without management presence, to discuss audit findings and other financial matters.

REPORT OF MANAGEMENT INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). The Company s internal controls have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements in accordance with U.S. generally accepted accounting principles. All internal control systems have inherent limitations, and therefore, can provide only reasonable assurance with respect to the reliability of financial reporting and preparation of consolidated financial statements.

Management has conducted an evaluation of the effectiveness of the Company s internal control over financial reporting based on the criteria set forth in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992. Based on the results of this evaluation, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2013.

KPMG LLP has performed an audit of the Company s internal control over financial reporting and their opinion thereon can be found on page F-3.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of Murphy Oil Corporation:

We have audited the accompanying consolidated balance sheets of Murphy Oil Corporation and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, cash flows, and stockholders equity for each of the years in the three-year period ended December 31, 2013. In connection with our audits of the consolidated financial statements, we also have audited financial statement Schedule II. These consolidated financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Murphy Oil Corporation and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Murphy Oil Corporation s internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2014 expressed an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas

February 28, 2014

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of Murphy Oil Corporation:

We have audited Murphy Oil Corporation s internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Murphy Oil 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. 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, Murphy Oil Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Murphy Oil Corporation as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, cash flows, and stockholders equity for each of the years in the three-year period ended December 31, 2013, and our report dated February 28, 2014 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas

February 28, 2014

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

December 31 *(Thousands of dollars)*	**2013**	2012
Assets		
Current assets		
Cash and cash equivalents	**$ 750,155**	947,316
Canadian government securities with maturities greater than 90 days at the date of acquisition	**374,842**	115,603
Accounts receivable, less allowance for doubtful accounts of $1,609 in 2013 and $6,697 in 2012	**999,872**	1,853,364
Inventories, at lower of cost or market		
Crude oil and blend stocks	**40,077**	226,541
Finished products	**0**	266,307
Materials and supplies	**254,118**	259,462
Prepaid expenses	**83,856**	335,831
Deferred income taxes	**61,991**	89,040
Assets held for sale	**943,732**	15,119
Total current assets	**3,508,643**	4,108,583
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $8,540,239 in 2013 and $8,138,587 in 2012	**13,481,055**	13,011,606
Goodwill	**40,259**	43,103
Deferred charges and other assets	**98,123**	151,183
Assets held for sale	**381,404**	208,168
Total assets	**$ 17,509,484**	17,522,643
Liabilities and Stockholders Equity		
Current liabilities		
Current maturities of long-term debt	**$ 26,249**	46
Accounts payable	**2,158,485**	2,803,268
Income taxes payable	**222,930**	219,847
Other taxes payable	**7,059**	172,962
Other accrued liabilities	**170,168**	162,876
Deferred income taxes	**0**	2,611
Liabilities associated with assets held for sale	**639,140**	47,471
Total current liabilities	**3,224,031**	3,409,081
Long-term debt, including capital lease obligation in 2013	**2,936,563**	2,245,201
Deferred income taxes	**1,466,100**	1,544,336
Asset retirement obligations	**852,488**	724,273
Deferred credits and other liabilities	**339,028**	516,540
Liabilities associated with assets held for sale	**95,544**	141,177
Stockholders equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued	**0**	0
Common Stock, par $1.00, authorized 450,000,000 shares at December 31, 2013 and 2012, issued 194,920,155 shares at December 31, 2013 and 194,616,470 shares at December 31, 2012	**194,920**	194,616
Capital in excess of par value	**902,633**	873,934
Retained earnings	**8,058,792**	7,717,389
Accumulated other comprehensive income	**172,119**	408,901
Treasury stock	**(732,734)**	(252,805)
Total stockholders equity	**8,595,730**	8,942,035

Total liabilities and stockholders equity	**$ 17,509,484**	17,522,643

See notes to consolidated financial statements, page F-9.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(Thousands of dollars except per share amounts)*	**2013**	2012*	2011*
Revenues			
Sales and other operating revenues	**$ 5,312,686**	4,608,563	4,222,520
Gain (loss) on sale of assets	**(87)**	66	23,143
Interest and other income	**77,490**	10,973	33,019
Total revenues	**5,390,089**	4,619,602	4,278,682
Costs and Expenses			
Operating expenses	**1,340,143**	1,114,748	1,010,121
Exploration expenses, including undeveloped lease amortization	**502,215**	380,924	489,346
Selling and general expenses	**379,167**	249,532	208,819
Depreciation, depletion and amortization	**1,553,394**	1,253,095	964,725
Impairment of properties	**21,587**	200,000	368,600
Accretion of asset retirement obligations	**48,996**	38,361	33,847
Redetermination of Terra Nova working interest	**0**	0	(5,351)
Interest expense	**124,423**	54,105	55,831
Interest capitalized	**(52,523)**	(39,173)	(15,131)
Total costs and expenses	**3,917,402**	3,251,592	3,110,807
Income from continuing operations before income taxes	**1,472,687**	1,368,010	1,167,875
Income tax expense	**584,550**	561,516	628,677
Income from continuing operations	**888,137**	806,494	539,198
Income from discontinued operations, net of income taxes	**235,336**	164,382	333,504
Net Income	**$ 1,123,473**	970,876	872,702
Income per Common Share Basic			
Income from continuing operations	**$ 4.73**	4.16	2.79
Income from discontinued operations	**1.25**	0.85	1.72
Net Income Basic	**$ 5.98**	5.01	4.51
Income per Common Share Diluted			
Income from continuing operations	**$ 4.69**	4.14	2.77
Income from discontinued operations	**1.25**	0.85	1.72
Net Income Diluted	**$ 5.94**	4.99	4.49
Average Common shares outstanding basic	**187,921,062**	193,902,335	193,409,621
Average Common shares outstanding diluted	**189,271,398**	194,668,737	194,512,402

See notes to consolidated financial statements, page F-9.

* Reclassified to conform to current presentation.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(Thousands of dollar)*	**2013**	2012	2011
Net income	**$ 1,123,473**	970,876	872,702
Other comprehensive income (loss), net of tax			
Net gain (loss) from foreign currency translation	**(308,300)**	117,331	(91,247)
Retirement and postretirement benefit plan adjustments	**69,583**	(17,650)	(30,909)
Deferred loss on interest rate hedges:			
Increase in deferred loss associated with contract revaluation and settlement	**0**	(2,407)	(16,852)
Amount of loss reclassified to interest expense in consolidated statements of income	**1,935**	1,207	0
Other comprehensive income (loss)	**(236,782)**	98,481	(139,008)
Comprehensive Income	**$ 886,691**	1,069,357	733,694

See notes to consolidated financial statements, page F-9.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(Thousands of dollar)*	**2013**	2012[1]	2011[1]
Operating Activities			
Net income	**$ 1,123,473**	970,876	872,702
Adjustments to reconcile net income to net cash provided by operating activities			
Income from discontinued operations	**(235,336)**	(164,382)	(333,504)
Depreciation, depletion and amortization	**1,553,394**	1,253,095	964,725
Impairment of long-lived assets	**21,587**	200,000	368,600
Amortization of deferred major repair costs	**8,464**	7,065	7,568
Expenditures for asset retirements	**(51,647)**	(40,434)	(21,490)
Dry hole costs	**262,876**	181,924	250,954
Amortization of undeveloped leases	**66,891**	129,750	118,211
Accretion of asset retirement obligations	**48,996**	38,361	33,847
Deferred and noncurrent income tax charges	**158,108**	342,718	133,841
Pretax (gains) losses from disposition of assets	**87**	(66)	(23,143)
Net decrease (increase) in noncash operating working capital	**266,329**	(168,180)	(760,036)
Other operating activities net	**(12,527)**	160,653	76,609
Net cash provided by continuing operations	**3,210,695**	2,911,380	1,688,884
Net cash provided by discontinued operations	**427,792**	144,901	456,501
Net cash provided by operating activities	**3,638,487**	3,056,281	2,145,385
Investing Activities			
Property additions and dry hole costs[2]	**(3,590,344)**	(3,541,724)	(2,433,088)
Proceeds from sale of property, plant and equipment	**1,650**	99	27,382
Expenditures for major repairs	**(7,757)**	(10,832)	(5,068)
Purchase of investment securities[3]	**(923,497)**	(1,619,308)	(1,689,087)
Proceeds from maturity of investment securities[3]	**664,258**	2,035,798	1,773,552
Other investing activities net	**8,048**	11,085	8,000
Investing activities of discontinued operations:			
Sales proceeds	**282,205**	0	950,010
Other	**(165,742)**	(192,540)	(246,055)
Net cash required by investing activities	**(3,731,179)**	(3,317,422)	(1,614,354)
Financing Activities			
Additions to long-term debt[2]	**350,000**	1,995,467	0
Repayments of debt	**0**	(350,000)	(340,041)
Purchase of treasury stock	**(500,000)**	(250,000)	0
Proceeds from exercise of stock options and employee stock purchase plans	**3,409**	12,324	15,551
Excess tax benefits related to exercise of stock options	**844**	2,647	4,838
Withholding tax on stock-based incentive awards	**(16,727)**	(3,341)	(8,014)
Issue cost of debt	**(3,317)**	(6,959)	(7,905)
Cash dividends paid	**(235,108)**	(714,429)	(212,752)
Cash included in current assets held for sale	**(301,302)**	0	0
Separation of retail business:			
Cash distributed to Murphy Oil by Murphy USA	**650,000**	0	0
Cash held and retained by Murphy USA upon separation	**(55,506)**	0	0
Net cash provided (required) by financing activities	**(107,707)**	685,709	(548,323)
Effect of exchange rate changes on cash and cash equivalents	**3,238**	8,875	(4,660)
Net increase (decrease) in cash and cash equivalents	**(197,161)**	433,443	(21,952)
Cash and cash equivalents at January 1	**947,316**	513,873	535,825

Cash and cash equivalents at December 31	$	**750,155**	947,316	513,873

[1] Reclassified to conform to current presentation.
[2] Excludes non-cash asset and long-term obligation of $357,991 in 2013 associated with lease commencement for production equipment at the Kakap field offshore Malaysia.
[3] Investments are Canadian government securities with maturities greater than 90 days at the date of acquisition.
See notes to consolidated financial statements, page F-9.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

Years Ended December 31 *(Thousands of dollar)*	**2013**	2012	2011
Cumulative Preferred Stock par $100, authorized 400,000 shares, none issued	**0**	0	0
Common Stock par $1.00, authorized 450,000,000 shares at December 31, 2013, 2012 and 2011, issued 194,920,155 shares at December 31, 2013, 194,616,470 shares at December 31, 2012 and 193,909,200 shares at December 31, 2011			
Balance at beginning of year	**$ 194,616**	193,909	193,294
Exercise of stock options	**304**	483	615
Awarded restricted stock	**0**	224	0
Balance at end of year	**194,920**	194,616	193,909
Capital in Excess of Par Value			
Balance at beginning of year	**873,934**	817,974	767,762
Exercise of stock options, including income tax benefits	**563**	12,717	21,774
Restricted stock transactions and other	**(28,339)**	(5,257)	(15,119)
Stock-based compensation	**56,622**	46,584	42,492
Sale of stock under employee stock purchase plans	**(147)**	1,916	1,065
Balance at end of year	**902,633**	873,934	817,974
Retained Earnings			
Balance at beginning of year	**7,717,389**	7,460,942	6,800,992
Net income for the year	**1,123,473**	970,876	872,702
Cash dividends $1.25 per share in 2013, $3.675 per share in 2012 and $1.10 per share in 2011	**(235,108)**	(714,429)	(212,752)
Distribution of common stock of Murphy USA Inc. to shareholders	**(546,962)**	0	0
Balance at end of year	**8,058,792**	7,717,389	7,460,942
Accumulated Other Comprehensive Income			
Balance at beginning of year	**408,901**	310,420	449,428
Foreign currency translation gains (losses), net of income taxes	**(308,300)**	117,331	(91,247)
Retirement and postretirement benefit plan adjustments, net of income taxes	**69,583**	(17,650)	(30,909)
Change in deferred loss on interest rate hedges, net of income taxes	**1,935**	(1,200)	(16,852)
Balance at end of year	**172,119**	408,901	310,420
Treasury Stock			
Balance at beginning of year	**(252,805)**	(4,848)	(11,926)
Purchase of treasury shares	**(500,000)**	(250,000)	0
Sale of stock under employee stock purchase plans	**1,015**	2,043	870
Awarded restricted stock, net of forfeitures	**19,056**	0	6,208
Balance at end of year 11,513,642 shares of Common Stock in 2013, 3,975,153 shares of Common Stock in 2012 and 185,992 shares of Common Stock in 2011	**(732,734)**	(252,805)	(4,848)

Total Stockholders Equity	**$ 8,595,730**	8,942,035	8,778,397

See notes to consolidated financial statements, page F-9.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note A Significant Accounting Policies

NATURE OF BUSINESS Murphy Oil Corporation is an international oil and gas company that conducts its business through various operating subsidiaries. The Company produces oil and natural gas in the United States, Canada and Malaysia and conducts oil and natural gas exploration activities worldwide. The Company has an interest in a Canadian synthetic oil operation. Murphy owns one petroleum refinery in the United Kingdom and markets petroleum products in that country under various brand names and to unbranded wholesale customers. The Company has announced its intention to sell the U.K. refining and marketing assets. On August 30, 2013, the Company completed the spin-off of Murphy USA Inc. (MUSA) to its shareholders. MUSA formerly was the Company s U.S. downstream operations. MUSA is now a separate, publicly owned company traded on the New York Stock Exchange under the symbol MUSA. In addition, Murphy Oil sold all its United Kingdom oil and natural gas producing assets during 2013. In 2011, the Company sold two U.S. petroleum refineries and certain associated marketing assets. See Note C regarding more information regarding the spin-off and sale of these assets.

PRINCIPLES OF CONSOLIDATION The consolidated financial statements include the accounts of Murphy Oil Corporation and all majority-owned subsidiaries. For consolidated subsidiaries that are less than wholly owned, the noncontrolling interest is reflected in the balance sheet as a component of Stockholders Equity. Undivided interests in oil and gas joint ventures are consolidated on a proportionate basis. Investments in affiliates in which the Company owns from 20% to 50% are accounted for by the equity method. Other investments are generally carried at cost. All significant intercompany accounts and transactions have been eliminated.

REVENUE RECOGNITION Revenues from sales of crude oil, natural gas and refined petroleum products are recorded when deliveries have occurred and legal ownership of the commodity transfers to the customer. Revenues from the production of oil and natural gas properties in which Murphy shares an undivided interest with other producers are recognized based on the actual volumes sold by the Company during the period. Natural gas imbalances occur when the Company s actual gas sales volumes differ from its entitlement under existing working interests. The Company records a liability for gas imbalances when it has sold more than its working interest of gas production and the estimated remaining reserves make it doubtful that partners can recoup their share of production from the field. At December 31, 2013 and 2012, the liabilities for natural gas balancing were immaterial.

Refined products sold at retail are recorded when the customer takes delivery at the pump. Title transfer for bulk motor fuel products generally occurs at pipeline custody points or upon truck loading at product terminals. Merchandise revenues are recorded at the point of sale.

The Company enters into buy/sell and similar arrangements when crude oil and other petroleum products are held at one location but are needed at a different location. The Company often pays or receives funds related to the buy/sell arrangement based on location or quality differences. The Company accounts for such transactions on a net basis in its Consolidated Statement of Income.

TAXES COLLECTED FROM CUSTOMERS AND REMITTED TO GOVERNMENT AUTHORITIES Excise and other taxes collected on sales of refined products and remitted to governmental agencies are excluded from revenues and costs and expenses in the Consolidated Statement of Income.

CASH EQUIVALENTS Short-term investments, which include government securities and other instruments with government securities as collateral, that have a maturity of three months or less from the date of purchase are classified as cash equivalents.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

MARKETABLE SECURITIES The Company classifies investments in marketable securities as available-for-sale or held-to-maturity. The Company does not have any investments classified as trading securities. Available-for-sale securities are carried at fair value with the unrealized gain or loss, net of tax, reported in other comprehensive income. Held-to-maturity securities are recorded at amortized cost. Premiums and discounts are amortized or accreted into earnings over the life of the related available-for-sale or held-to-maturity security.

Dividend and interest income is recognized when earned. Unrealized losses considered to be other than temporary are recognized currently in earnings. The cost of securities sold is based on the specific identification method. The fair value of investment securities is determined by available market prices. At December 31, 2013, the Company owned Canadian government securities with maturities greater than 90 days at date of acquisition that had a carrying value of $374,842,000. These securities are readily marketable and could be quickly converted to cash if needed to meet operating cash needs in Canada.

ACCOUNTS RECEIVABLE At December 31, 2013, the Company s accounts receivable primarily consisted of amounts owed to the Company by customers for sales of crude oil and natural gas. In 2012 this balance included receivables for oil and gas sales and amounts owed for refined products sold under varying credit arrangements in the U.S. and U.K. The allowance for doubtful accounts is the Company s best estimate of the amount of probable credit losses on these receivables. The Company reviews this allowance for adequacy at least quarterly and bases its assessment on a combination of current information about its customers and historical write-off experience. Any trade accounts receivable balances written off are charged against the allowance for doubtful accounts. The Company has not experienced any significant credit-related losses in the past three years.

INVENTORIES Crude oil and blend stocks inventories include unsold crude oil production in 2013 and 2012, and in 2012 also included Milford Haven refinery feedstocks. Unsold crude oil production is carried in inventory at the lower of cost, generally applied on a first-in, first-out (FIFO) basis, or market, and includes costs incurred to bring the inventory to its existing condition. Refinery inventories of crude oil and other feedstocks and certain finished product inventories are valued at the lower of cost, generally applied on a last-in, first-out (LIFO) basis, or market. Merchandise inventory held for resale at retail marketing stations in 2012 was generally carried at average cost and was included in Finished products inventories. Materials and supplies inventories are valued at the lower of average cost or estimated value and generally consist of tubulars and other drilling equipment and additionally at year-end 2012 it included spare parts for refinery operations. Cash collected upon the sale of inventory to customers is classified as an operating activity in the Consolidated Statement of Cash Flows.

PROPERTY, PLANT AND EQUIPMENT The Company uses the successful efforts method to account for exploration and development expenditures. Leasehold acquisition costs are capitalized. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties. Costs of undeveloped leases associated with unproved properties are expensed over the life of the leases. Exploratory well costs are capitalized pending determination about whether proved reserves have been found. In certain cases, a determination of whether a drilled exploratory well has found proved reserves cannot be made immediately. This is generally due to the need for a major capital expenditure to produce and/or evacuate the hydrocarbon(s) found. The determination of whether to make such a capital expenditure is usually dependent on whether further exploratory wells find a sufficient quantity of additional reserves. The Company continues to capitalize exploratory well costs in Property, Plant and Equipment when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The Company reevaluates its capitalized drilling costs at least annually to ascertain whether drilling costs continue to qualify for ongoing capitalization. Other exploratory costs, including geological and geophysical costs, are charged to expense as incurred. Development costs, including unsuccessful development wells, are capitalized. Interest is capitalized on significant development projects that are expected to take one year or more to complete.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Oil and gas properties are evaluated by field for potential impairment. Other properties are evaluated for impairment on a specific asset basis or in groups of similar assets as applicable. An impairment is recognized when the estimated undiscounted future net cash flows of an asset are less than its carrying value. If an impairment occurs, the carrying value of the impaired asset is reduced to fair value.

The Company records a liability for asset retirement obligations (ARO) equal to the fair value of the estimated cost to retire an asset. The ARO liability is initially recorded in the period in which the obligation meets the definition of a liability, which is generally when a well is drilled or the asset is placed in service. The ARO liability is estimated by the Company s engineers using existing regulatory requirements and anticipated future inflation rates.

When the liability is initially recorded, the Company increases the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is increased over time to reflect the change in its present value, and the capitalized cost is depreciated over the useful life of the related long-lived asset. The Company reevaluates the adequacy of its recorded ARO liability at least annually. Actual costs of asset retirements such as dismantling oil and gas production facilities and site restoration are charged against the related liability. Any difference between costs incurred upon settlement of an asset retirement obligation and the recorded liability is recognized as a gain or loss in the Company s earnings.

Depreciation and depletion of producing oil and gas properties is recorded based on units of production. Unit rates are computed for unamortized exploration drilling and development costs using proved developed reserves; unit rates for unamortized leasehold costs and asset retirement costs are amortized over proved reserves. Proved reserves are estimated by the Company s engineers and are subject to future revisions based on availability of additional information. The Milford Haven, Wales refinery, certain marketing facilities and certain natural gas processing facilities are depreciated primarily using the composite straight-line method with depreciable lives ranging from 14 to 25 years. Gasoline stations and other properties are depreciated over 3 to 20 years by individual unit on the straight-line method. Gains and losses on asset disposals or retirements are included in income as a separate component of revenues. Property and equipment of U.K. refining and marketing operations are no longer depreciated following the recognition of these assets as held for sale in late 2013.

Turnarounds for major processing units at the Milford Haven, Wales refinery are scheduled at four to five year intervals. Turnarounds for coking units at Syncrude Canada Ltd. are scheduled at intervals of two to three years. Turnaround work associated with various other less significant units at Milford Haven and Syncrude varies depending on operating requirements and events. Murphy defers turnaround costs incurred and amortizes such costs over the period until the next scheduled turnaround. This amortization is recorded in Operating Expenses for Syncrude and through results of discontinued operation for the Milford Haven refinery. Also in 2014, amortization of deferred turnaround costs will cease for the U.K. downstream operations that are held for sale. All other maintenance and repairs are expensed as incurred. Renewals and betterments are capitalized. A major turnaround occurred in 2010 at the Milford Haven, Wales refinery.

CAPITALIZED INTEREST Interest associated with borrowings from third parties is capitalized on significant oil and gas development projects when the expected development period extends for one year or more. Interest capitalized is credited in the Consolidated Statement of Income and is added to the cost of the underlying asset for the development project in Property, Plant and Equipment in the Consolidated Balance Sheet. Capitalized interest is amortized over the useful life of the asset in the same manner as other development costs.

GOODWILL Goodwill is recorded in an acquisition when the purchase price exceeds the fair value of net assets acquired. All recorded goodwill arose from the purchase of an oil and natural gas company by Murphy s wholly owned Canadian subsidiary in 2000. Goodwill is not amortized, but is assessed annually for

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

recoverability of the carrying value. The Company assesses goodwill recoverability at each year-end by comparing the fair value of net assets for conventional oil and natural gas properties in Canada with the carrying value of these net assets including goodwill. The fair value of the conventional oil and natural gas reporting unit is determined using the expected present value of future cash flows. The change in the carrying value of goodwill during 2013 was primarily caused by a change in the foreign currency translation rate between years. Based on its assessment of the fair value of its Canadian conventional oil and natural gas operations, the Company believes the recorded value of goodwill is not impaired at December 31, 2013. Should a future assessment indicate that goodwill is not fully recoverable, an impairment charge to write down the carrying value of goodwill would be required.

ENVIRONMENTAL LIABILITIES A liability for environmental matters is established when it is probable that an environmental obligation exists and the cost can be reasonably estimated. If there is a range of reasonably estimated costs, the most likely amount will be recorded, or if no amount is most likely, the minimum of the range is used. Related expenditures are charged against the liability. Environmental remediation liabilities have not been discounted for the time value of future expected payments. Environmental expenditures that have future economic benefit are capitalized.

INCOME TAXES The Company accounts for income taxes using the asset and liability method. Under this method, income taxes are provided for amounts currently payable and for amounts deferred as tax assets and liabilities based on differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities. Deferred income taxes are measured using the enacted tax rates that are assumed will be in effect when the differences reverse. The Company routinely assesses the realizability of deferred tax assets based on available evidence including assumptions of future taxable income, tax planning strategies and other pertinent factors. A deferred tax asset valuation allowance is recorded when evidence indicates that it is more likely than not that all or a portion of these deferred tax assets will not be realized in a future period. The Company does not provide U.S. deferred taxes for the portion of undistributed earnings of foreign subsidiaries when these earnings are considered indefinitely reinvested in the respective foreign operations. The accounting rules for income tax uncertainties permit recognition of income tax benefits only when they are more likely than not to be realized. The Company includes potential penalties and interest for uncertain income tax positions in income tax expense.

FOREIGN CURRENCY Local currency is the functional currency used for recording operations in Canada and for refining and marketing activities in the United Kingdom. The U.S. dollar is the functional currency used to record all other operations. Exchange gains or losses from transactions in a currency other than the functional currency are included in earnings. Gains or losses from translating foreign functional currencies into U.S. dollars are included in Accumulated Other Comprehensive Income in Stockholders Equity.

DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES The fair value of a derivative instrument is recognized as an asset or liability in the Company s Consolidated Balance Sheet. Upon entering into a derivative contract, the Company may designate the derivative as either a fair value hedge or a cash flow hedge, or decide that the contract is not a hedge for accounting purposes, and thenceforth, recognize changes in the fair value of the contract in earnings. The Company documents the relationship between the derivative instrument designated as a hedge and the hedged items as well as its objective for risk management and strategy for use of the hedging instrument to manage the risk. Derivative instruments designated as fair value or cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. The Company assesses at inception and on an ongoing basis whether a derivative instrument accounted for as a hedge is highly effective in offsetting changes in the fair value or cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting. The change in the fair value of a qualifying fair value hedge is recorded in earnings along with the gain or loss on the hedged item. The effective portion of the change in the fair value of a qualifying cash flow hedge is recorded in other comprehensive income until the hedged item is

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

recognized in earnings. When the income effect of the underlying cash flow hedged item is recognized in the Consolidated Statement of Income, the fair value of the associated cash flow hedge is reclassified from other comprehensive income into earnings. The ineffective portion of the change in fair value of a cash flow hedge is recognized currently in earnings. If a derivative instrument no longer qualifies as a cash flow hedge and the underlying forecasted transaction is no longer probable of occurring, hedge accounting is discontinued and the gain or loss recorded in other comprehensive income is recognized immediately in earnings.

FAIR VALUE MEASUREMENTS The Company carries certain assets and liabilities at fair value in its Consolidated Balance Sheet. Fair value is determined using various techniques depending on the availability of observable inputs. Level 1 inputs include quoted prices in active markets for identical assets or liabilities. Level 2 inputs include observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs which reflect assumptions about pricing by market participants.

STOCK-BASED COMPENSATION

Equity-Settled Awards The fair value of awarded stock options, restricted stock units and other stock-based compensation that are settled with Company shares is determined based on a combination of management assumptions and the market value of the Company s common stock. The Company uses the Black-Scholes option pricing model for computing the fair value of equity-settled stock options. The primary assumptions made by management include the expected life of the stock option award and the expected volatility of Murphy s common stock prices. The Company uses both historical data and current information to support its assumptions. Stock option expense is recognized on a straight-line basis over the respective vesting period of two or three years. The Company uses a Monte Carlo valuation model to determine the fair value of performance-based restricted stock units that are equity settled and expense is recognized over the three-year vesting period. The fair value of time-lapse restricted stock units is determined based on the price of Company stock on the date of grant and expense is recognized over the vesting period. The Company estimates the number of stock options and performance-based restricted stock units that will not vest and adjusts its compensation expense accordingly. Differences between estimated and actual vested amounts are accounted for as an adjustment to expense when known.

Cash-Settled Awards The Company accounts for stock appreciation rights (SAR), cash-settled restricted stock units (CRSU) and phantom stock units as liability awards. Expense associated with these awards are recognized over the vesting period based on the latest available estimate of the fair value of the awards, which is generally determined using a Black-Scholes method for SAR, a Monte Carlo method for CRSU, and the period-end price of the Company s common stock for phantom units. When SAR are exercised and when CRSU and phantom units expire, the Company adjusts previously recorded expense to the final amounts paid out in cash for these awards.

NET INCOME PER COMMON SHARE Basic income per common share is computed by dividing net income for each reporting period by the weighted average number of common shares outstanding during the period. Diluted income per common share is computed by dividing net income for each reporting period by the weighted average number of common shares outstanding during the period plus the effects of all potentially dilutive common shares.

USE OF ESTIMATES In preparing the financial statements of the Company in conformity with U.S. generally accepted accounting principles, management has made a number of estimates and assumptions related to the reporting of assets, liabilities, revenues, and expenses and the disclosure of contingent assets and liabilities. Actual results may differ from the estimates.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Note B New Accounting Principles and Recent Accounting Pronouncements

Accounting Principles Adopted

In February 2013, the Financial Accounting Standards Board (FASB) issued an accounting standards update that requires additional disclosures for reclassification adjustments from accumulated other comprehensive income (AOCI). These additional disclosures include changes in AOCI balances by component and significant items reclassified out of AOCI. These disclosures must be presented either on the face of the affected financial statement or in the notes to the financial statements. The disclosures are effective for Murphy Oil beginning in the first quarter of 2013 and are to be provided on a prospective basis. These disclosures are presented in Note O.

In December 2011, the FASB issued an accounting standards update that requires enhanced disclosures about financial instruments and derivative instruments that are either offset in the balance sheet or are subject to an enforceable master netting arrangement or similar agreement. The guidance was effective for all interim and annual periods beginning on or after January 1, 2013. These disclosures are presented in Note P.

Note C Discontinued Operations

Separation of U.S. Downstream Business

On August 30, 2013, Murphy Oil Corporation (the Company) distributed 100% of the outstanding common stock of Murphy USA Inc. (MUSA) to its shareholders in a generally tax-free spin-off for U.S. federal income tax purposes. After the close of the New York Stock Exchange on August 30, 2013, the Company s shareholders of record as of 5:00 p.m. Eastern time on August 21, 2013 received one share of MUSA common stock for every four common shares of the Company held by such shareholders. Prior to the separation, MUSA held all of the Company s U.S. downstream operations, including retail gasoline stations and other marketing assets, plus two ethanol production facilities. In connection with the separation, Murphy Oil USA, Inc., MUSA s 100% owned primary operating subsidiary, distributed $650,000,000 to the Company in the form of a cash dividend. These funds were raised from the proceeds of $500,000,000 secured notes issued by Murphy Oil USA, Inc. plus $150,000,000 borrowed under credit facilities entered into by MUSA and Murphy Oil USA, Inc. in connection with the separation. The shares of MUSA common stock are traded on the New York Stock Exchange under the ticker symbol MUSA. The Company has no continuing involvement with MUSA operations. Accordingly, the operating results and the cash flows for these former U.S. downstream operations have been reported as discontinued operations for all periods presented in the consolidated financial statements. These operations were formerly reported as the U.S. refining and marketing segment in prior years financial statements.

In order to effect the separation and govern the Company s relationship with MUSA after the separation, both parties entered into a series of agreements governing each party s rights and obligations after the separation. Among such agreements, the Separation and Distribution Agreement governs the separation of the U.S. downstream business, the transfer of assets, cross-indemnities between the Company and MUSA, handling of claims subject to indemnification and related matters, and other matters related to the Company s relationship with MUSA.

The Tax Matters Agreement governs the respective rights, responsibilities and obligations of the Company and MUSA with respect to taxes, tax attributes, tax returns, tax proceedings and certain other tax matters. In addition, the Tax Matters Agreement imposes certain restrictions on MUSA and its subsidiaries (including restrictions on share issuances, business combinations, sales of assets and similar transactions) that are designed to preserve the tax-free status of the distribution.

The Employee Matters Agreement governs the compensation and employee benefit obligations with respect to the current and former employees and non-employee directors of the Company and MUSA, and generally

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

allocates liabilities and responsibilities relating to employee compensation, benefit plans and programs. The Employee Matters Agreement provides that employees of MUSA will no longer participate in benefit plans sponsored or maintained by the Company. In addition, the Employee Matters Agreement provides that each of the parties will be responsible for their respective current employees and compensation plans for such current employees, and that the Company will be responsible for liabilities relating to former employees who left prior to the separation. The Employee Matters Agreement sets forth the general principles relating to employee matters and also addresses any special circumstances during the transition period. The Employee Matters Agreement also provides that (i) the distribution does not constitute a change in control under existing plans, programs, agreements or arrangements, and (ii) the distribution and the assignment, transfer or continuation of the employment of employees with another entity will not constitute a severance event under the applicable plans, programs, agreements or arrangements.

The Transition Service Agreement sets forth the terms on which the Company and MUSA will provide certain services or functions to the other party. Transition services include administration, payroll, human resources, data processing, environmental health and safety, audit support, financial transaction support, and other support services, information technology systems and various other corporate services. The agreement provides for the provision of specified services, generally for a period of up to 18 months, with a possible extension of six months (an aggregate of 24 months), on a full cost basis.

Other Discontinued Operations

Additionally, the Company completed the sale of all of its U.K. oil and natural gas production assets during 2013. The Company recognized an after-tax gain of $216,147,000 on sale of these U.K. oil and gas assets during 2013. The results of the operations have also been reported as discontinued operations for all periods presented in these consolidated financial statements.

The Company has previously announced its intention to sell its U.K. refining and marketing operations. Beginning in 2013, the Company has accounted for the U.K. downstream business as discontinued operations for all periods presented, including a reclassification of all the prior years operating results for this business to discontinued operations. The U.K. downstream operations were formerly reported as a separate segment within the Company s refining and marketing business. The sale process continues in 2014.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

The following table presents the carrying value of the major categories of assets and liabilities of discontinued operations reflected on the Company s consolidated balance sheets at December 31, 2013 and 2012:

(Millions of dollars)	**2013**	2012
Current assets		
Held for sale assets of U.K. downstream operations:		
Cash	**$ 301,302**	0
Accounts receivable	**302,059**	0
Inventories	**254,240**	0
Other	**86,131**	0
Held for sale assets of U.K. oil and gas operations	**0**	15,119
Total current assets held for sale	**$ 943,732**	15,119
Non-current assets		
Held for sale assets of U.K. downstream operations:		
Property, plant and equipment, net	**$ 360,347**	0
Other	**21,057**	0
Held for sale assets of U.K. oil and gas operations:		
Property, plant and equipment	**0**	205,746
Other	**0**	2,422
Total non-current assets held for sale	**$ 381,404**	208,168
Current liabilities		
Current liabilities associated with held for sale properties of U.K. downstream operations:		
Accounts payable	**$ 637,432**	0
Other	**1,708**	0
Current liabilities associated with held for sale properties of U.K. oil and gas operations:		
Accounts payable	**0**	27,578
Income taxes payable	**0**	19,893
Total current liabilities associated with assets held for sale	**$ 639,140**	47,471
Non-current liabilities		
Non-current liabilities associated with held for sale properties of U.K. downstream operations:		
Deferred income taxes payable	**$ 68,096**	0
Deferred credits and other liabilities	**27,448**	0
Non-current liabilities associated with held for sale properties of U.K. oil and gas operations:		
Deferred income taxes payable	**0**	87,893
Asset retirement obligations	**0**	53,284
Total non-current liabilities associated with assets held for sale	**$ 95,544**	141,177

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

As described above, the Company separated its U.S. downstream operations in 2013. The major categories of assets and liabilities for MUSA were included in the Company s consolidated balance sheet at December 31, 2012 as follows:

(Millions of dollars)	2012
Current assets	
Accounts receivable	$ 525,936
Inventories	217,393
Other current assets	8,685
Total current assets	$ 752,014
Non-current assets	
Property, plant and equipment, net	$ 1,163,748
Other assets	498
Total non-current assets	$ 1,164,246
Current liabilities	
Accounts payable	$ 612,755
Income taxes payable	16,851
Other taxes payable	65,349
Other current liabilities	38,798
Total current liabilities	$ 733,753
Non-current liabilities	
Long-term debt	$ 1,123
Deferred income taxes	89,946
Asset retirement obligations	15,401
Deferred credits and other liabilities	87,600
Total non-current liabilities	$ 194,070

In 2013, the Company wrote down its net investment in the held for sale U.K. refining and marketing assets by $73,000,000. This charge has been included in discontinued operations for 2013. The write down was based on an assessment of the fair value of these assets based on the status of the ongoing sale process.

At year-end 2012, the Company wrote down its net investment in the ethanol production facility in Hereford, Texas, taking an impairment charge of $60,988,000 in discontinued operations. The write down was required based on expected weak ethanol production margins at the plant in future periods. Fair value was determined using a discounted cash flow model for three years, plus an estimated terminal value based on a multiple of the last year s cash flow. Certain key assumptions used in the cash flow model included use of available futures prices for corn and ethanol products. Additional key assumptions included estimated future ethanol and distillers grain production levels, estimated future operating expenses, and estimated sales prices for distillers grain.

In July 2012, the United Kingdom enacted tax changes that limited tax relief on oil and gas decommissioning costs to 50%, a reduction from the 62% tax relief previously allowed for these costs. This tax rate change led to a net reduction of income from discontinued operations of $5,523,000 in 2012. In July 2011, the United Kingdom enacted a supplemental tax rate increase for oil and gas companies effective retroactive to March 2011. The total U.K. tax rate increased from 50% to 62% for oil and gas companies. The supplemental tax rate change reduced income from discontinued operations by $14,461,000 for 2011.

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On September 30, 2011, the Company sold the Superior, Wisconsin refinery and related assets for $214,000,000, plus certain capital expenditures between July 25, 2011, and the date of closing and the fair value of all associated hydrocarbon inventories at these locations. On October 1, 2011, the Company sold its Meraux, Louisiana refinery and related assets for $325,000,000, plus the fair value of associated hydrocarbon inventories. The Company has accounted for the results of the Superior, Wisconsin and Meraux, Louisiana refineries and associated marketing assets as discontinued operations. The after-tax gain in 2011 from disposal of the two refineries netted to $18,724,000, made up of a gain on the Superior refinery (including associated inventories) of $77,585,000 and a loss on the Meraux refinery (including associated inventories) of $58,861,000. The gain on disposal in 2011 was based on refinery selling prices, plus the sale of all associated inventories at fair value, which was significantly above the last-in, first-out cost method. The net gain on sale of the refineries included an after-tax benefit of $179,152,000 from liquidation of inventories formerly carried primarily under the last-in, first-out cost method. The U.S. refineries sold were formerly reported in the U.S. manufacturing segment.

The results of operations associated with all discontinued operations are presented in the following table.

(Thousands of dollars)	**2013**	2012	2011
Revenues	**$ 17,586,236**	24,156,748	27,310,300
Income from operations before income taxes	**$ 119,984**	330,048	571,339
Gain on sale before income taxes	**130,991**	0	12,684
Total income from discontinued operations before taxes	**250,975**	330,048	584,023
Provision for income taxes	**15,639**	165,666	250,519
Income from discontinued operations	**$ 235,336**	164,382	333,504

Note D Property, Plant and Equipment

	December 31, 2013		December 31, 2012	
(Thousands of dollars)	**Cost**	**Net**	Cost	Net
Exploration and production[1]	**$ 21,932,119**	**13,433,468[2]**	18,408,904	11,294,933[2]
Refining and marketing	**0**	**0**	2,619,844	1,661,081
Corporate and other	**89,175**	**47,587**	121,445	55,592
	$ 22,021,294	**13,481,055**	21,150,193	13,011,606
[1] Includes mineral rights as follows:	**$ 1,007,920**	**489,578**	1,051,153	556,399

[2] Includes $48,691 in 2013 and $26,611 in 2012 related to administrative assets and support equipment.

Under FASB guidance exploratory well costs should continue to be capitalized when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

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At December 31, 2013, 2012 and 2011, the Company had total capitalized drilling costs pending the determination of proved reserves of $393,030,000, $445,697,000 and $556,412,000, respectively. The following table reflects the net changes in capitalized exploratory well costs during the three-year period ended December 31, 2013.

(Thousands of dollars)	**2013**	2012	2011
Beginning balance at January 1	**$ 445,697**	556,412	497,765
Additions to capitalized exploratory well costs pending the determination of proved reserves	**57,716**	135,849	86,035
Reclassifications to proved properties based on the determination of proved reserves	**(93,936)**	(165,377)	0
Capitalized exploratory well costs charged to expense	**(16,447)**	(81,187)	(27,388)
Ending balance at December 31	**$ 393,030**	445,697	556,412

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of projects for which exploratory well costs has been capitalized since the completion of drilling.

	2013			2012			2011		
(Thousands of dollars)	**Amount**	**No. of Wells**	**No. of Projects**	Amount	No. of Wells	No. of Projects	Amount	No. of Wells	No. of Projects
Aging of capitalized well costs:									
Zero to one year	**$ 56,499**	**3**	**1**	$ 59,833	7	2	$ 69,757	11	5
One to two years	**60,787**	**7**	**1**	18,335	2	3	143,611	15	3
Two to three years	**0**	**0**	**0**	83,314	9	4	101,696	9	2
Three years or more	**275,744**	**22**	**7**	284,215	26	6	241,348	33	6
	$ 393,030	**32**	**9**	$ 445,697	44	15	$ 556,412	68	16

Of the $336,531,000 of exploratory well costs capitalized more than one year at December 31, 2013, $213,802,000 is in Malaysia, $116,123,000 is in the U.S. and $6,606,000 is in Brunei. In Malaysia either further appraisal or development drilling is planned and/or development studies/plans are in various stages of completion. In the U.S. further drilling is anticipated and development plans are being formulated. In Brunei development options are under review for these multiple gas discoveries. The capitalized well costs charged to expense in 2013 included two wells offshore Sarawak Malaysia that were written off due to the Company s decision not to move forward with development of the wells. The capitalized well costs charged to expense in 2012 included a suspended well in the northern block of the Republic of the Congo that was written off following unsuccessful wildcat drilling in 2012 at a nearby prospect, two suspended wells offshore Sarawak Malaysia that were written off following a decision not to continue development of the wells, and a well drilled in the Gulf of Mexico in 2010 that the owners decided not to develop. The capitalized well costs expensed in 2011 related to exploration costs offshore Republic of the Congo and Brunei. The costs in Republic of the Congo were written off following an impairment charge at the nearby Azurite field, and the Brunei costs were written off based on unsuccessful wells drilled in the area in late 2011.

At year-end 2012, Murphy determined that the Azurite field, offshore Republic of the Congo, was impaired due to removal of all proved oil reserves after an unsuccessful redrill of a key well in the field. The impairment charge in 2012 totaled $200,000,000 and included a write-off of the remaining book value of the Azurite field plus other anticipated losses related to operations of the field. An impairment charge of $368,600,000 was

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

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recorded in 2011 to reduce the carrying value of the Azurite field to fair value. The Company determined that a downward revision of proved oil reserves for Azurite was necessary at year-end 2011 following an extensive study of the declining well production at the field. It was determined that the remaining reserves, including risked estimated probable and possible reserves, would not allow for recovery of the Company s net investment in the Azurite field. Fair value was determined each year at Azurite using a discounted cash flow model based on certain key assumptions, including future estimated net production levels, future estimated oil prices for the field based on year-end futures prices, and future estimated operating and capital expenditures.

The Company has announced that its Board of Directors had approved plans to exit the U.K. refining and marketing business. These operations are presented as discontinued operations in Note C. The sale process for the U.K. downstream assets continues in 2014.

Note E   Financing Arrangements

At December 31, 2013, the Company had a $2.0 billion committed credit facility with a major banking consortium that expires in June 2017. Borrowings under this facility bear interest at 1.25% above LIBOR based on the Company s current credit rating as of December 31, 2013. In addition, facility fees of 0.25% are charged on the full $2.0 billion commitment. In May 2013, the Company increased the capacity of the committed credit facility from $1.5 billion to $2.0 billion and extended the maturity date by one year from June 2016 to June 2017. At December 31, 2013, the Company had borrowings of $350,000,000 under this committed facility. At December 31, 2013, the Company also had uncommitted credit lines that had estimated total borrowing capacity of approximately $345,000,000. No borrowings were outstanding under these uncommitted credit lines at December 31, 2013. If necessary, the Company could borrow funds under all or certain of these uncommitted lines with various financial institutions in future periods. The Company has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities through October 2015.

Note F   Long-term Debt

	December 31	
(Thousands of dollars)	**2013**	2012
Notes payable		
2.50% notes, due 2017	**$ 550,000**	550,000
3.70% notes, due 2022	**600,000**	600,000
4.00% notes, due 2022	**500,000**	500,000
7.05% notes, due 2029	**250,000**	250,000
5.125% notes, due 2042	**350,000**	350,000
Notes payable to banks, 1.4375% at December 31, 2013	**350,000**	0
Other, 6%, due through 2028	**0**	1,169
Total notes payable	**2,600,000**	2,251,169
Unamortized discount on notes payable	**(5,439)**	(5,922)
Total notes payable, net of unamortized discount	**2,594,561**	2,245,247
Capitalized lease obligation, due through June 2028	**368,251**	0
Total debt including current maturities	**2,962,812**	2,245,247
Current maturities	**(26,249)**	(46)
Total long-term debt	**$ 2,936,563**	2,245,201

Long-term debt amounts repayable over each of the next five years and thereafter are as follows: $26,249,000 in 2014, $17,921,000 in 2015, $18,819,000 in 2016, $919,700,000 in 2017, $20,752,000 in 2018 and $1,959,371,000 thereafter.

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The capitalized lease obligation included in the above table is associated with production facilities at the Kakap field, offshore Sarawak, Malaysia. The facilities are utilized by the Company under a 25 year lease that extends through 2038.

Note G Asset Retirement Obligations

The asset retirement obligations liabilities (ARO) recognized by the Company at December 31, 2013 and 2012 are related to the estimated costs to dismantle and abandon its producing oil and gas properties and related equipment.

The Company has not recorded an ARO for its refining and marketing assets in the U.K. because sufficient information is presently not available to estimate a range of potential settlement dates for the obligation. These assets are held for sale at December 31, 2013. If these assets are not sold as anticipated, the ARO obligation will be initially recognized in the period in which sufficient information exists to estimate the liability.

A reconciliation of the beginning and ending aggregate carrying amount of the asset retirement obligation for 2013 and 2012 is shown in the following table.

(Thousands of dollars)	**2013**	2012
Balance at beginning of year	**$ 751,583**	615,545
Accretion expense	**48,996**	39,341[1]
Liabilities incurred	**172,048**	184,439
Revision of previous estimates	**(4,856)**	10,468
Liabilities settled	**(51,647)**	(40,434)
Liabilities assumed by Murphy USA Inc. upon separation	**(15,401)**	0
U.K. oil and gas asset obligations reclassified to liabilities associated with assets held for sale in 2012	**0**	(64,355)
Changes due to translation of foreign currencies	**(20,720)**	6,579
Balance at end of year	**880,003**	751,583
Current portion of liability at end of year[2]	**(27,515)**	(27,310)
Noncurrent portion of liability at end of year	**$ 852,488**	724,273

1 Includes $980 reclassified to discontinued operations associated with U.S. downstream operations.
2 Included in Other Accrued Liabilities on the Consolidated Balance Sheet.

The estimation of future ARO is based on a number of assumptions requiring professional judgment. The Company cannot predict the type of revisions to these assumptions that may be required in future periods due to the availability of additional information such as: prices for oil field services, technological changes, governmental requirements and other factors.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Note H Income Taxes

The components of income from continuing operations before income taxes for each of the three years ended December 31, 2013 and income tax expense attributable thereto were as follows.

(Thousands of dollars)	**2013**	2012	2011
Income (loss) from continuing operations before income taxes			
United States	**$ (5,810)**	54,275	72,038
Foreign	**1,478,497**	1,313,735	1,095,837
	$ 1,472,687	1,368,010	1,167,875
Income tax expense (benefit)			
Federal Current	**$ (56,790)**	(256,931)	6,050
Deferred	**65,883**	177,325	15,633
	9,093	(79,606)	21,683
State	**7,141**	8,104	5,609
Foreign Current	**477,715**	472,701	471,960
Deferred	**90,601**	160,317	129,425
	568,316	633,018	601,385
Total	**$ 584,550**	561,516	628,677

Income tax benefits attributable to employee stock option transactions of $7,435,000 in 2013, $5,920,000 in 2012 and $8,775,000 in 2011 were included in Capital in Excess of Par Value within Stockholders Equity in the Consolidated Balance Sheets.

The following table reconciles income taxes based on the U.S. statutory tax rate to the Company s income tax expense.

(Thousands of dollars)	**2013**	2012	2011
Income tax expense based on the U.S. statutory tax rate	**$ 515,440**	478,804	408,756
Foreign income subject to foreign taxes at a rate different than the U.S. statutory rate	**31,752**	7,710	(10,682)
State income taxes, net of federal benefit	**4,642**	5,268	3,646
U.S. tax benefit on certain foreign upstream investments	**(133,526)**	(108,077)	0
Increase in deferred tax asset valuation allowance related to other foreign exploration expenditures	**129,588**	87,558	102,714
Impairment or abandonment of Azurite field with no tax benefit	**35,475**	70,000	129,010
Malaysian tax benefits on prior year costs in Block P	**0**	0	(25,573)
Other, net	**1,179**	20,253	20,806

Total	**$ 584,550**	561,516	628,677

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

An analysis of the Company s deferred tax assets and deferred tax liabilities at December 31, 2013 and 2012 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	**2013**	2012
Deferred tax assets		
Property and leasehold costs	**$ 708,947**	658,588
Liabilities for dismantlements	**79,111**	78,100
Postretirement and other employee benefits	**175,446**	197,912
Alternative minimum tax	**49,536**	37,253
Foreign tax credit carryforwards	**19,896**	18,594
Other deferred tax assets	**23,352**	32,500
Total gross deferred tax assets	**1,056,288**	1,022,947
Less valuation allowance	**(633,735)**	(523,966)
Net deferred tax assets	**422,553**	498,981
Deferred tax liabilities		
Property, plant and equipment	**(747,561)**	(808,311)
Accumulated depreciation, depletion and amortization	**(1,040,251)**	(1,077,867)
Other deferred tax liabilities	**(38,849)**	(70,710)
Total gross deferred tax liabilities	**(1,826,661)**	(1,956,888)
Net deferred tax liabilities	**$ (1,404,108)**	(1,457,907)

In management s judgment, the net deferred tax assets in the preceding table will more likely than not be realized as reductions of future taxable income or by utilizing available tax planning strategies. The valuation allowance for deferred tax assets relates primarily to tax assets arising in foreign tax jurisdictions and foreign tax credit carryforwards. In the judgment of management at the present time, these tax assets are not likely to be realized. The foreign tax credit carryforwards expire in 2015 through 2022. The valuation allowance increased $109,769,000 in 2013, with these changes primarily offsetting the change in certain deferred tax assets. Any subsequent reductions of the valuation allowance will be reported as reductions of tax expense assuming no offsetting change in the deferred tax asset.

The Company has not recognized a deferred tax liability for undistributed earnings of its Canadian and certain other foreign subsidiaries because such earnings are considered indefinitely invested in foreign countries. As of December 31, 2013, undistributed earnings of the Company s subsidiaries considered indefinitely invested were approximately $6,677,000,000. The unrecognized deferred tax liability is dependent on many factors including withholding taxes under current tax treaties and foreign tax credits and is estimated to be approximately $651,000,000. The Company does not consider undistributed earnings from certain other international operations to be indefinitely invested; however, any estimated tax liabilities upon repatriation of earnings from these international operations are expected to be offset with foreign tax credits. Although the Company does not foresee repatriating earnings considered indefinitely invested, under present law, it would incur a 5% withholding tax on any monies repatriated from Canada to the United States.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS   Continued

Uncertain Income Tax Positions

The FASB s rules for accounting for income tax uncertainties clarify the criteria for recognizing uncertain income tax benefits and require additional disclosures about uncertain tax positions. Under current rules the financial statement recognition of the benefit for a tax position is dependent upon the benefit being more likely than not to be sustainable upon audit by the applicable taxing authority. If this threshold is met, the tax benefit is then measured and recognized at the largest amount that is greater than 50 percent likely of being realized upon ultimate settlement. Liabilities associated with uncertain income tax positions are included in Deferred Credits and Other Liabilities in the Consolidated Balance Sheet. A reconciliation of the beginning and ending amount of the consolidated liability for unrecognized income tax benefits during the three years ended December 31, 2013 is shown in the following table.

(Thousands of dollars)	**2013**	2012	2011
Balance at January 1	**$ 16,611**	18,857	23,196
Additions for tax positions related to current year	**2,486**	1,258	1,294
Settlements due to lapse of time	**(12,731)**	(3,504)	(5,633)
Balance at December 31	**$ 6,366**	16,611	18,857

All additions or reductions to the above liability affect the Company s effective income tax rate in the respective period of change. The Company accounts for any applicable interest and penalties on uncertain tax positions as a component of income tax expense. The Company also had other recorded liabilities as of December 31, 2013 and 2012 for interest and penalties of $146,000 and $975,000, respectively, associated with uncertain tax positions. Income tax expense for the years ended December 31, 2013, 2012 and 2011 included net benefits for interest and penalties of $829,000, $1,000 and $34,000, respectively, associated with uncertain tax positions.

During the next twelve months, the Company currently expects to add between $1,000,000 and $2,000,000 to the liability for uncertain taxes for 2014 events. Although existing liabilities could be reduced by settlement with taxing authorities or lapse due to statute of limitations, the Company believes that the changes in its unrecognized tax benefits due to these events will not have a material impact on the Consolidated Statement of Income during 2014.

The Company s tax returns in multiple jurisdictions are subject to audit by taxing authorities. These audits often take years to complete and settle. Although the Company believes that recorded liabilities for unsettled issues are adequate, additional gains or losses could occur in future years from resolution of outstanding unsettled matters. As of December 31, 2013, the earliest years remaining open for audit and/or settlement in the Company s major taxing jurisdictions are as follows: United States 2010; Canada 2007; United Kingdom 2011; and Malaysia 2006.

Note I   Incentive Plans

Murphy utilizes cash-based and/or share-based incentive plans to supplement normal salaries as compensation for executive management and certain employees. For share-based awards that qualify for equity accounting, costs are recognized as an expense in the financial statements using a grant date fair value-based measurement method over the periods that the awards vest. For share-based awards that are required to be accounted for under liability accounting rules, costs are recognized as expense using a fair value-based measurement method over the vesting period, but expense is adjusted as necessary through the date the award value is finally determined. Total expense for liability awards is ultimately adjusted to the final intrinsic value for the award.

In 2012, the Company s shareholders approved replacement of the 2007 Annual Incentive Plan (2007 Annual Plan) and the 2007 Long-Term Incentive Plan (2007 Long-Term Plan) with the 2012 Annual Incentive Plan (2012 Annual Plan) and 2012 Long-Term Incentive Plan (2012 Long-Term Plan), respectively. All awards to employees on or after May 9, 2012 have been made under the respective 2012 plans.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

The 2012 Annual Plan and the 2007 Annual Plan authorize the Executive Compensation Committee (the Committee) to establish specific performance goals associated with annual cash awards that may be earned by officers, executives and certain other employees. Cash awards under the 2012 Annual Plan and 2007 Annual Plan are determined based on the Company s actual financial and operating results as measured against the performance goals established by the Committee. The 2012 Long-Term Plan and the 2007 Long-Term Plan authorize the Committee to make grants of the Company s Common Stock to employees. These grants may be in the form of stock options (nonqualified or incentive), stock appreciation rights (SAR), restricted stock, restricted stock units, performance units, performance shares, dividend equivalents and other stock-based incentives. The 2012 Long-Term Plan expires in 2022. A total of 8,700,000 shares are issuable during the life of the 2012 Long-Term Plan, with annual grants limited to 1% of Common shares outstanding; allowed shares not granted may be granted in future years. Based on awards made to date, approximately 7,135,000 shares remained available for grant under the 2012 Long-Term Plan at December 31, 2013. The Company also has a 2013 Stock Plan for Non-Employee Directors (Director Plan) that permits the issuance of restricted stock, restricted stock units and stock options or a combination thereof to the Company s Non-Employee Directors.

The Company generally expects to issue treasury shares to satisfy future stock option exercises and vesting of restricted stock and restricted stock units.

Amounts recognized in the financial statements with respect to share-based plans are shown in the following table.

(Thousands of dollars)	**2013**	2012	2011
Compensation charged against income before income tax benefit	**$ 66,976**	46,694	43,272
Related income tax benefit recognized in income	**19,321**	14,443	14,396

As of December 31, 2013, there was $59,505,000 in compensation costs to be expensed over approximately the next two years related to unvested share-based compensation arrangements granted by the Company. Cash received from options exercised under all share-based payment arrangements for the years ended December 31, 2013, 2012 and 2011 was $2,395,000, $10,375,000 and $13,251,000, respectively. Total income tax benefits realized from tax deductions related to stock option exercises under share-based payment arrangements were $7,435,000, $5,920,000 and $8,775,000 for the years ended December 31, 2013, 2012 and 2011, respectively.

STOCK OPTIONS The Committee fixes the option price of each option granted at no less than fair market value (FMV) on the date of the grant and fixes the option term at no more than seven years from such date. Each option granted to date under the 2012 Long-Term Plan and the 2007 Long-Term Plan has been nonqualified, with a term of seven years and an option price equal to FMV at date of grant. Under the 2012 Long-Term Plan and the 2007 Long-Term Plan, one-half of each grant is generally exercisable after two years and the remainder after three years. For stock options, the number of shares issued upon exercise is reduced for settlement of applicable statutory income tax withholdings owed by the grantee. Under the Director Plan, one-third of each grant is exercisable after each of the first three years.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

The fair value of each option award is estimated on the date of grant using the Black-Scholes pricing model based on the assumptions noted in the following table. Expected volatility is based on historical volatility of the Company s stock and implied volatility on publicly traded at-the-money options on the Company s stock. The Company estimates the expected term of the options granted based on historical option exercise patterns and considers certain groups of employees exhibiting different behavior. The risk-free interest rate for periods within the expected term of the option is based on the U.S. Treasury yield curve in effect at the time of grant.

	2013		2012		2011
Fair value per option grant	**$15.81**	**$20.62**	$12.37	$17.74	$20.34
Assumptions					
Dividend yield	**2.10%**	**2.30%**	1.80%	2.27%	1.80%
Expected volatility	**34.00%**	**36.00%**	39.00%	39.62%	37.00%
Risk-free interest rate	**0.96%**	**2.00%**	0.55%	0.77%	2.10%
Expected life	**5.25 yrs.**	**6.50 yrs.**	4.00 yrs.	5.20 yrs.	5.10 yrs.

Changes in stock options outstanding during the last three years are presented in the following table.

	Number of Shares	Average Exercise Price
Outstanding at December 31, 2010	5,302,384	$ 48.83
Granted at FMV	1,397,312	67.64
Exercised	(974,500)	39.30
Forfeited	(290,968)	52.73
Outstanding at December 31, 2011	5,434,228	55.17
Granted at FMV	1,870,500	57.96
Exercised	(823,855)	38.37
Forfeited	(573,514)	60.43
Outstanding at December 31, 2012	5,907,359	55.17
Granted at FMV	**1,320,176**	**55.26**
Exercised	**(1,335,355)**	**45.84**
Forfeited	**(228,576)**	**58.01**
Surrendered in connection with separation of Murphy USA Inc.	**(272,936)**	**55.99**
Murphy USA Inc. spin-off adjustment	**615,917**	**52.09**
Outstanding at December 31, 2013	**6,006,585**	**56.80**
Exercisable at December 31, 2010	2,499,610	$ 45.07
Exercisable at December 31, 2011	2,319,735	51.14
Exercisable at December 31, 2012	2,474,636	54.43
Exercisable at December 31, 2013	**2,435,322**	**51.79**

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Additional information about stock options outstanding at December 31, 2013 is shown below.

Range of Exercise Prices per Option	Options Outstanding No. of Options	Avg. Life Remaining in Years	Aggregate Intrinsic Value	Options Exercisable No. of Options	Avg. Life Remaining in Years	Aggregate Intrinsic Value
$37.44 to $39.02	658,782	3.1	$ 17,677,000	406,939	1.4	$ 11,165,000
$43.88 to $51.63	2,233,621	4.5	34,786,000	832,631	2.4	16,224,000
$54.21 to $63.46	3,114,182	4.6	21,288,000	1,195,752	2.4	4,500,000
	6,006,585	4.4	$ 73,751,000	2,435,322	2.2	$ 31,889,000

The total intrinsic value of options exercised during 2013, 2012 and 2011 was $25,284,000, $17,197,000 and $28,145,000, respectively. Intrinsic value is the excess of the market price of stock at date of exercise over the exercise price received by the Company upon exercise. Aggregate intrinsic value is nil when the exercise price of the stock option exceeds the market price of the Company s Common stock.

In February 2013, the Committee reduced the exercise price of all outstanding stock options by $2.50 per share to reflect the impact of the special dividend of the same amount paid in December 2012. The exercise prices in the tables above beginning in 2013 reflect this $2.50 reduction in exercise price approved in 2013. The income statement effect of this reduced exercise price was an expense of $6,454,000 in 2013.

In order to preserve the economic value of unexercised stock options following the spin-off of Murphy USA Inc. on August 30, 2013, the number of outstanding stock options was increased by 10.7% and the exercise price of stock options was reduced by 10.7%. The number of options and the exercise prices in the tables above reflect these adjustments related to the MUSA spin-off. There was no immediate impact on the expense for stock options recognized in 2013 related to this exercise price adjustment.

Stock Appreciation Rights (SAR) SAR may be granted in conjunction with or independent of stock options. During 2013 the Committee granted SAR with terms similar to stock options granted in 2013. Upon exercise of SAR, the intrinsic value will be settled, net of applicable income tax withholdings, in cash rather than with Common shares. The initial fair value of these SAR were equivalent to stock options granted, but the fair value of these liability-type awards are adjusted quarterly based on changes in the key assumptions and the change in price of Murphy Oil shares. The liability was calculated at a price of $64.88 per SAR unit at December 31, 2013. None of these SARs are exercisable at December 31, 2013. At the time of the Murphy USA Inc. spin-off, the number of outstanding SAR and the exercise price of these SAR were adjusted in a manner similar to stock options as described above. Changes in SAR outstanding beginning in 2013 are presented in the following table.

	Number of SAR	Average Exercise Price
Outstanding at December 31, 2012	**0**	
Granted	**851,000**	**$ 54.21**
Forfeited	**(68,712)**	
Surrendered in connection with separation of Murphy USA Inc.	**(73,000)**	
Murphy USA Inc. spin-off adjustment	**78,824**	
Outstanding at December 31, 2013	**788,112**	**$ 54.21**

PERFORMANCE-BASED RESTRICTED STOCK UNITS AND CASH-SETTLED RESTRICTED STOCK UNITS Restricted stock units (RSU) to be settled in Common shares were granted in each of the last three

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

years under the 2012 Long-Term Plan or the 2007 Long-Term Plan. Each grant will vest if the Company achieves specific performance objectives at the end of the designated performance period. Additional shares may be awarded if performance objectives are exceeded. If performance goals are not met, shares under performance-based grants will not vest, but recognized compensation cost associated with the stock award would not be reversed. For past awards, the performance conditions were based on the Company s total shareholder return over the performance period compared to an industry peer group of companies. During the performance period, RSU are subject to transfer restrictions and are subject to forfeiture if a grantee terminates for reasons other than retirement, disability or death. Termination for these three reasons will lead to a pro rata award of amounts earned. No dividends are paid or voting rights exist on awards of RSU prior to their settlement.

In 2013, the Committee granted both equity-settled and cash-settled performance-based restricted stock units to certain employees. The terms of the cash-settled awards are similar to other performance-based restricted stock awards, except that they are to be settled, net of applicable tax withholdings, in cash rather than Common shares if performance targets are met. The initial fair value of these cash-settled awards are equivalent to other awards settled in shares, however, the cash-settled awards are considered to be liability awards and the fair value thereon is adjusted quarterly based on changes in the key assumptions and the price of Murphy Oil s Common stock.

Upon the separation of Murphy USA Inc. on August 30, 2013, adjustments to outstanding performance-based restricted stock units were made to the number of units outstanding to preserve the economic value of these equity-settled and cash-settled awards.

Changes in performance-based RSU outstanding for each of the last three years are presented in the following table.

	Equity-Settled Restricted Stock Units			Cash-Settled Restricted Stock Units
(Number of share units)	**2013**	2012	2011	**2013**
Balance at beginning of year	**1,426,238**	1,174,492	1,023,492	**0**
Granted	**521,776**	653,355	521,423	**93,200**
Awarded	**(380,150)**	(260,175)	(309,656)	**0**
Forfeited	**(39,573)**	(141,434)	(60,767)	**(9,924)**
Surrendered in connection with separation of Murphy USA Inc.	**(116,568)**	0	0	**(6,800)**
Murphy USA Inc. spin-off adjustment	**148,569**	0	0	**8,380**
Balance at end of year	**1,560,292**	1,426,238	1,174,492	**84,856**

The fair value of the equity-settled performance-based awards granted in each year was estimated on the date of grant using a Monte Carlo valuation model. Expected volatility was based on daily historical volatility of the Company s stock price compared to a peer group average over a three-year period. The risk-free interest rate is based on the yield curve of three-year U.S. Treasury bonds and the stock beta was calculated using three years of historical averages of daily stock data for Murphy and the peer group. The assumptions used in the valuation of the performance awards granted in 2013, 2012 and 2011 are presented in the following table.

	2013		2012		2011	
Fair value per share at grant date	**$39.50**	**$68.01**	$54.90	$63.64	$38.94	$64.89
Assumptions						
Expected volatility	**31.00%**	**32.00%**	37.00%		51.00%	
Risk-free interest rate	**0.41%**	**0.62%**	0.30%		1.04%	
Stock beta	**0.907**	**0.908**	0.913		1.006	
Expected life	**3.00 yrs.**		3.00 yrs.		3.00 yrs.	

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

TIME-LAPSE RESTRICTED STOCK UNITS Restricted stock units (RSU) have been granted to the Company s Non-Employee Directors under the Directors Plan. These awards vest on the third anniversary of the date of grant. The fair value of these awards was estimated based on the market value of the Company s stock on the date of grant, which were $60.30 per share and $69.67 per share in 2013, $59.33 per share in 2012 and $52.66 per share in 2011. To retain economic value at the time of spin-off of Murphy USA Inc., the number of time-lapse restricted stock units was increased by 10.7% for each unit outstanding on August 30, 2013.

Changes in time-lapse restricted stock units outstanding for each of the last three years are presented in the following table.

(Number of share units)	**2013**	2012	2011
Balance at beginning of year	**98,477**	116,724	166,173
Granted	**38,184**	42,256	32,711
Vested and issued	**(34,696)**	(44,980)	(82,160)
Forfeited	**0**	(15,523)	0
Murphy USA Inc. spin-off adjustment	**10,916**	0	0
Balance at end of year	**112,881**	98,477	116,724

PHANTOM UNITS Phantom units have been granted to certain Company employees during 2012 and 2013. These awards will be settled in cash generally after three year terms based on the average of the high and low price for the Company s Common stock on the maturity dates. To retain economic value at the time of spin-off of Murphy USA Inc., phantom unit awards were increased by 10.7% for each unit outstanding on August 30, 2013. Total expense related to these phantom awards was $2,063,000 in 2013 and $305,000 in 2012.

PERFORMANCE UNITS The Company also awarded performance units in 2011 through 2013 to certain U.S. retail marketing employees under the 2012 Long-Term Plan and 2007 Long-Term Plan. The performance units were to be paid in cash and awards are computed at between 0% and 200% of targeted amounts based on achievement of U.S. retail financial performance over the three-year term of the award. These performance units were all settled and paid in connection with the separation of Murphy USA Inc. No performance units remain outstanding at December 31, 2013. Total expense related to these awards was $2,062,000 in 2013, $2,665,000 in 2012 and $871,000 in 2011.

EMPLOYEE STOCK PURCHASE PLAN (ESPP) The Company has an ESPP under which the Company s Common stock can be purchased by eligible U.S. and Canadian employees. Each quarter, an eligible employee may elect to withhold up to 10% of his or her salary to purchase shares of the Company s stock at the end of the quarter at a price equal to 90% of the fair value of the stock as of the first day of the quarter. The ESPP will terminate on the earlier of the date that employees have purchased all 980,000 authorized shares or June 30, 2017. Employee stock purchases under the ESPP were 16,020 shares at an average price of $54.14 per share in 2013, 24,418 shares at an average price of $48.54 per share in 2012 and 28,555 shares at an average price of $55.28 per share in 2011. At December 31, 2013, 286,941 shares remained available for sale under the ESPP. Compensation costs related to the ESPP are estimated based on the value of the 10% discount and the fair value of the option that provides for the refund of participant withholdings, and such expenses were $143,000 in 2013, $272,000 in 2012 and $328,000 in 2011. The fair value per share issued under the ESPP was approximately $6.72, $7.30 and $8.60 for the years ended December 31, 2013, 2012 and 2011, respectively.

SAVINGS-RELATED SHARE OPTION PLAN (SOP) One of the Company s U.K. subsidiaries formerly provided a plan that allowed shares of the Company s Common stock to be purchased by eligible employees using payroll withholdings. An eligible employee could have elected to withhold from £5 to £250 per month to purchase shares of Company stock at a price equal to 90% of the fair value of the stock as of the date of grant.

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The SOP plan had a term of three years and employee withholdings were fixed over the life of the plan. At the end of the term of the SOP plan an employee received interest on withholdings and had six months to either use all or part of the withholdings plus credited interest to purchase shares of Company stock or receive a repayment of withholdings plus credited interest. The SOP expired in 2012. Compensation costs related to the SOP plan were estimated based on the value of the 10% discount and the fair value of the option that allowed the employee to receive a repayment of withholdings plus credited interest. The fair value per share of the SOP plans with holding periods that ended in April 2011 and May 2012 were $23.77 and $22.85, respectively. Total expense associated with this plan was nil in 2013, $110,000 in 2012 and $538,000 in 2011.

CASH AWARDS The Committee also administers the Company s incentive compensation plans, which provide for annual or periodic cash awards to officers, directors and certain other employees. These cash awards are generally determinable based on the Company achieving specific financial and/or operational objectives. Compensation expense of $53,250,000, $32,417,000 and $33,035,000 was recorded in 2013, 2012 and 2011, respectively, for these plans.

Note J Employee and Retiree Benefit Plans

PENSION AND OTHER POSTRETIREMENT PLANS The Company has defined benefit pension plans that are principally noncontributory and cover most full-time employees. All pension plans are funded except for the U.S. and Canadian nonqualified supplemental plans and the U.S. directors plan. All U.S. tax qualified plans meet the funding requirements of federal laws and regulations. Contributions to foreign plans are based on local laws and tax regulations. The Company also sponsors health care and life insurance benefit plans, which are not funded, that cover most retired U.S. employees. The health care benefits are contributory; the life insurance benefits are noncontributory.

Effective with the spin-off of Murphy s former U.S. retail marketing operation, Murphy USA Inc. (MUSA) on August 30, 2013, significant modifications were made to the U.S. defined benefit pension plan. Certain Murphy employees benefits under the U.S. plan were frozen at that time. No further benefit service will accrue for the affected employees, however, the plan will recognize future earnings after the spin-off. In addition, all previously unvested benefits became fully vested at the spin-off date. For those affected active employees of the Company, additional U.S. retirement plan benefits will accrue in future periods under a cash balance formula. Upon the spin-off of MUSA, Murphy retained all vested pension defined benefit and other postretirement benefit obligations associated with current and former employees of this separated business. No additional benefit will accrue for any employees of MUSA under the Company s retirement plan after the spin-off date.

Generally accepted accounting principles require the Company to recognize the overfunded or underfunded status of its defined benefit plans as an asset or liability in its year-end consolidated balance sheet and to recognize changes in that funded status between periods through comprehensive income.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

The tables that follow provide a reconciliation of the changes in the plans benefit obligations and fair value of assets for the years ended December 31, 2013 and 2012 and a statement of the funded status as of December 31, 2013 and 2012.

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	**2013**	2012	**2013**	2012
Change in benefit obligation				
Obligation at January 1	**$ 721,531**	629,568	**124,134**	114,962
Service cost	**26,346**	23,500	**4,566**	3,958
Interest cost	**30,903**	29,869	**5,189**	5,174
Plan amendments	**1,989**	0	**0**	0
Participant contributions	**21**	30	**1,376**	1,035
Actuarial loss (gain)	**(9,876)**	55,479	**(8,324)**	4,686
Medicare Part D subsidy	**0**	0	**384**	432
Exchange rate changes	**1,852**	7,125	**(36)**	14
Benefits paid	**(38,745)**	(30,217)	**(5,211)**	(6,127)
Special termination benefits	**849**	6,177	**0**	0
Curtailments	**(26,463)**	0	**(15,077)**	0
Obligation assumed by MUSA at separation	**(1,153)**	0	**0**	0
Obligation at December 31	**707,254**	721,531	**107,001**	124,134
Change in plan assets				
Fair value of plan assets at January 1	**463,546**	404,350	**0**	0
Actual return on plan assets	**61,932**	41,674	**0**	0
Employer contributions	**46,726**	42,207	**3,451**	4,660
Participant contributions	**21**	30	**1,376**	1,035
Medicare Part D subsidy	**0**	0	**384**	432
Exchange rate changes	**1,594**	6,289	**0**	0
Benefits paid	**(38,745)**	(30,217)	**(5,211)**	(6,127)
Other	**(1,966)**	(787)	**0**	0
Fair value of plan assets at December 31	**533,108**	463,546	**0**	0
Funded status and amounts recognized in the Consolidated Balance Sheets at December 31				
Deferred charges and other assets	**10,254**	9,679	**0**	0
Other accrued liabilities	**(5,565)**	(5,556)	**(5,920)**	(5,646)
Deferred credits and other liabilities	**(158,589)**	(262,108)	**(101,081)**	(118,488)
Liabilities associated with assets held for sale	**(20,246)**	0	**0**	0
Funded status and net plan liability recognized at December 31	**$ (174,146)**	(257,985)	**(107,001)**	(124,134)

At December 31, 2013, amounts included in accumulated other comprehensive income (AOCI), before reduction for associated deferred income taxes, which have not been recognized in net periodic benefit expense are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
Net actuarial loss	**$ (150,682)**	**(13,815)**
Prior service (cost) credit	**(3,559)**	**372**
Transitional asset (liability)	**517**	**0**
	$ (153,724)	**(13,443)**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Amounts included in AOCI at December 31, 2013 that are expected to be amortized into net periodic benefit expense during 2014 are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
Net actuarial loss	**$ (8,190)**	**(242)**
Prior service (cost) credit	**(951)**	**82**
Transitional asset (liability)	**517**	**0**
	$ (8,624)	**(160)**

The table that follows includes projected benefit obligations, accumulated benefit obligations and fair value of plan assets for plans where the accumulated benefit obligation exceeded the fair value of plan assets.

	Projected Benefit Obligations		Accumulated Benefit Obligations		Fair Value of Plan Assets	
(Thousands of dollars)	**2013**	2012	**2013**	2012	**2013**	2012
Funded qualified plans where accumulated benefit obligation exceeds fair value of plan assets	**$ 571,217**	587,318	**520,610**	523,773	**502,308**	431,788
Unfunded nonqualified and directors plans where accumulated benefit obligation exceeds fair value of plan assets	**115,492**	112,135	**102,198**	98,498	**0**	0
Unfunded other postretirement plans	**107,001**	124,134	**107,001**	124,134	**0**	0

The table that follows provides the components of net periodic benefit expense for each of the three years ended December 31, 2013.

	Pension Benefits			Other Postretirement Benefits		
(Thousands of dollars)	**2013**	2012	2011	**2013**	2012	2011
Service cost	**$ 26,346**	23,500	22,406	**4,566**	3,958	4,547
Interest cost	**30,903**	29,869	30,785	**5,189**	5,174	6,141
Expected return on plan assets	**(28,974)**	(25,826)	(25,919)	**0**	0	0
Amortization of prior service cost (credit)	**1,006**	1,254	1,314	**(143)**	(173)	(240)
Amortization of transitional (asset) liability	**(514)**	(529)	(536)	**8**	8	8
Recognized actuarial loss	**17,338**	16,389	12,484	**1,484**	1,317	2,329
	46,105	44,657	40,534	**11,104**	10,284	12,785
Termination benefits expense	**849**	6,177	695	**0**	0	0
Curtailment expense (benefit)	**1,365**	0	1,036	**(442)**	0	(605)
Net periodic benefit expense	**$ 48,319**	50,834	42,265	**10,662**	10,284	12,180

Termination and curtailment expenses in 2013 primarily related to plan amendments made at the time of separation of Murphy USA Inc. The increase in net periodic pension benefit expense in 2012 compared to 2011 was primarily related to expense recognized in 2012 for enhanced retirement benefits provided to a former executive officer. Termination and curtailment expenses in 2011 related to sale of two U.S. petroleum refineries during that year. The reduction in the net periodic benefit expense for other postretirement plans in 2012 was due to no further service costs and lower other costs associated with postretirement benefits for the Meraux and Superior refineries sold in 2011.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

The preceding tables in this note include the following amounts related to foreign benefit plans.

(Thousands of dollars)	Pension Benefits **2013**	Pension Benefits 2012	Other Postretirement Benefits **2013**	Other Postretirement Benefits 2012
Benefit obligation at December 31	**$ 211,799**	184,550	**541**	525
Fair value of plan assets at December 31	**188,575**	164,111	**0**	0
Net plan liabilities recognized	**23,224**	20,439	**541**	525
Net periodic benefit expense	**12,622**	11,022	**92**	88

The following table provides the weighted-average assumptions used in the measurement of the Company s benefit obligations at December 31, 2013 and 2012 and net periodic benefit expense for 2013 and 2012.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits December 31		Other Postretirement Benefits December 31		Pension Benefits Year		Other Postretirement Benefits Year	
	2013	2012	**2013**	2012	**2013**	2012	**2013**	2012
Discount rate	**4.78%**	4.24%	**4.91%**	4.18%	**4.23%**	4.80%	**4.18%**	4.87%
Expected return on plan assets	**6.24%**	6.20%	**0%**	0%	**6.24%**	6.20%	**0%**	0%
Rate of compensation increase	**4.14%**	4.13%	**0%**	0%	**4.12%**	4.10%	**0%**	0%

The discount rates used for determining the plan obligations and expense are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate which is the basis for selecting the discount rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Expected compensation increases are based on anticipated future averages for the Company.

Benefit payments, reflecting expected future service as appropriate, which are expected to be paid in future years from the assets of the plans or by the Company are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
2014	$ 32,822	6,746
2015	33,459	6,971
2016	33,723	7,148
2017	34,455	7,303
2018	35,383	7,500
2019-2023	194,717	41,148

For purposes of measuring postretirement benefit obligations at December 31, 2013, the future annual rates of increase in the cost of health care were assumed to be 7.4% for 2014 decreasing each year to an ultimate rate of 5.0% in 2020 and thereafter.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Assumed health care cost trend rates have a significant effect on the expense and obligation reported for the postretirement benefit plan. A 1% change in assumed health care cost trend rates would have the following effects.

(Thousands of dollars)	1% Increase	1% Decrease
Effect on total service and interest cost components of net periodic postretirement benefit expense for the year ended December 31, 2013	$ 2,011	(1,551)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 2013	14,331	(11,812)

During 2013, the Company made contributions of $30,570,000 to its domestic defined benefit pension plans, $16,156,000 to its foreign defined benefit pension plans, $3,412,000 to its domestic postretirement benefits plan and $39,000 to its foreign postretirement benefits plan. The Company currently expects during 2014 to make contributions of $27,133,000 to its domestic defined benefit pension plans, $21,977,000 to its foreign defined benefit pension plans, $5,883,000 to its domestic postretirement benefits plan and $36,000 to its foreign postretirement benefits plan.

U.S. Health Care Reform In March 2010, the United States Congress enacted a health care reform law. Along with other provisions, the law (a) eliminated the tax free status of federal subsidies to companies with qualified retiree prescription drug plans that are actuarially equivalent to Medicare Part D plans beginning in 2013; (b) imposes a 40% excise tax on high-cost health plans as defined in the law beginning in 2018; (c) eliminated lifetime or annual coverage limits and required coverage for preventative health services beginning in September 2010; and (d) imposed a fee of $2 (subsequently adjusted for inflation) for each person covered by a health insurance policy beginning in September 2010. The Company provides a health care benefit plan to eligible U.S. employees and most U.S. retired employees. The law did not significantly affect the Company s consolidated financial statements as of December 31, 2013, 2012 and 2011 and for the years then ended. The Company continues to evaluate the various components of the law as guidance is issued and cannot predict with certainty all the ways it may impact the Company. However, based on information available to date, the Company currently believes that the health care reform law will not have a material effect on its financial condition, net income or cash flow in future periods.

Plan Investments Murphy Oil Corporation maintains an Investment Policy Statement (Statement) that establishes investment standards related to its two funded domestic qualified retirement plans. The Statement specifies that all assets will be held in a Master Trust sponsored by the Company, which is administrated by a trustee appointed by the Investment Committee (Committee). Members of the Committee are appointed by the Board of Directors. The Committee hires Investment Managers to invest trust assets within the guidelines established by the Committee as allowed by the Statement. The investment goals call for a portfolio of assets consisting of equity, fixed income and cash equivalent securities. The primary consideration for investments is the preservation of capital, and investment growth should exceed the rate of inflation. The Committee has directed the asset investment advisors of its benefit plans to maintain a portfolio consisting of both equity and fixed income securities. The Company believes that over time a balanced to slightly heavier weighting of the portfolio in equity securities compared to fixed income securities represents the most appropriate long-term mix for future investment return on assets held by domestic plans. The parameters for asset allocation call for the following minimum and maximum percentages: equity securities of between 40% and 70%; fixed income securities of between 30% and 60%; long/short equity of between 0% and 15%; and cash and equivalents of between 0% and 15%. The Committee is authorized to direct investments within these parameters. Equity investments may include common, preferred and convertible preferred stocks, emerging markets stocks and similar funds, and long/short equity funds. Long/short equity is a strategy invested in a portfolio of long stocks hedged with short sales of stocks and/or stock index options, with the combination of investment intended to produce equity-like returns with lower volatility over the long term. Generally no more than 10% of an

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Investment Manager s portfolio is to be held in equity securities of any one issuer, and equity securities should have a minimum market capitalization of $100 million. Equities held in the trust should be listed on the New York or American Stock Exchanges, principal U.S. regional exchanges, major foreign exchanges or quoted in significant over-the-counter markets. Equity or fixed income securities issued by the Company may not be held in the trust. Fixed income securities include maturities greater than one year to maturity. The fixed income portfolio should not exceed an average maturity of 11 years. The portfolio may include investment grade corporate bonds, issues of the U.S. government, its agencies and government sponsored entities, government agency issued collateralized mortgage backed securities, agency issued mortgage backed securities, municipal bonds, asset backed securities, commercial mortgage backed securities and international and emerging markets bond funds. The Committee routinely reviews the investment performance of Investment Managers.

For the U.K. retirement plan, trustees have been appointed by the wholly-owned subsidiary that sponsors the plan for U.K. employees. The trustees have hired an investment consultant to manage the assets of the plan within the parameters of the Investment Policy Implementation Document (Document). The objective of investments is to earn a reasonable return within the allocation strategy permitted in the Document while limiting the risk for the funded position of the plan. The Document specifies a strategy with an allocation goal of 60% equities and 40% bonds. The Document allows for ranges of equity investments from 27% to 98%, fixed income securities may range from 25% to 60%, and cash can be held for up to 5% of investments. Approximately one-half of the equity allocation is to be invested in U.K. securities and the remainder split between North American, European, Japanese and other Pacific Basin securities. A minimum of 95% of the fixed income allocation is to be invested in U.K. securities with up to 5% in international or high yield bonds. Tolerance ranges are specified in the Document within the general equity/bond allocation guidelines. Asset performance is compared to a benchmark return based on the allocation guidelines and is targeted to outperform the benchmark by 0.75% per annum over a rolling three-year period. Small working cash balances are permitted to facilitate daily management of payments and receipts within the plan. The trustees routinely review the investment performance of the plan.

For the Canadian retirement plan, the wholly-owned subsidiary that sponsors the plan has a Statement of Investment Policies and Procedures (Policy) applicable to the plan assets. A pension committee appointed by the board of directors of the subsidiary oversees the plan, selects the investment advisors and routinely reviews performance of the asset portfolio. The Policy permits assets to be invested in various Canadian and foreign equity securities, various fixed income securities, real estate, natural resource properties or participation rights and cash. The objective for plan investments is to achieve a total rate of return equal to the long-term interest rate assumption used for the going-concern actuarial funding valuation. The normal allocation includes total equity securities of 60% with a range of 40% to 75% of total assets. Fixed income securities have a normal allocation of 35% with a range of 25% to 45%. Cash will normally have an allocation of 5% with a range of 0% to 15%. The Policy calls for diversification norms within the investment portfolios of both equity securities and fixed income securities.

The weighted average asset allocation for the Company s funded pension benefit plans at December 31, 2013 and 2012 are presented in the following table.

	December 31,	
	2013	2012
Equity securities	**68.4%**	62.9%
Fixed income securities	**30.7**	36.1
Cash equivalents	**0.9**	1.0
	100.0%	100.0%

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

The Company s weighted average expected return on plan assets was 6.24% in 2013 and the return was determined based on an assessment of actual long-term historical returns and expected future returns for a portfolio with investment characteristics similar to that maintained by the plans. The 6.24% expected return was based on an expected average future equity securities return of 8.40% and a fixed income securities return of 3.90% and is net of average expected investment expenses of 0.45%. Over the last 10 years, the return on funded retirement plan assets has averaged 6.93%.

At December 31, 2013, the fair value measurements of retirement plan assets within the fair value hierarchy are included in the table that follows.

		Fair Value Measurements Using		
(Thousands of dollars)	**Fair Value at December 31, 2013**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Domestic Plans				
Equity securities:				
U.S. core equity	**$ 89,255**	**89,255**	**0**	**0**
U.S. small/midcap	**37,149**	**37,149**	**0**	**0**
Hedged funds and other alternative strategies	**32,788**	**0**	**0**	**32,788**
International commingled trust fund	**77,041**	**0**	**77,041**	**0**
Emerging market commingled equity fund	**9,654**	**0**	**9,654**	**0**
Fixed income securities:				
U.S. fixed income	**72,240**	**0**	**72,240**	**0**
International commingled trust fund	**14,865**	**0**	**14,865**	**0**
Emerging market mutual fund	**8,549**	**0**	**8,549**	**0**
Cash and equivalents	**2,992**	**2,992**	**0**	**0**
Total Domestic Plans	**344,533**	**129,396**	**182,349**	**32,788**
Foreign Plans				
Equity securities funds	**99,085**	**0**	**99,085**	**0**
Fixed income securities funds	**57,030**	**0**	**57,030**	**0**
Diversified pooled fund	**30,800**	**0**	**30,800**	**0**
Cash and equivalents	**1,660**	**1,660**	**0**	**0**
Total Foreign Plans	**188,575**	**1,660**	**186,915**	**0**
Total	**$ 533,108**	**131,056**	**369,264**	**32,788**

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

At December 31, 2012, the fair value measurements of retirement plan assets within the fair value hierarchy are included in the table that follows.

		Fair Value Measurements Using		
(Thousands of dollars)	Fair Value at December 31, 2012	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Domestic Plans				
Equity securities:				
U.S. core equity	$ 83,392	83,392	0	0
U.S. small/midcap	20,894	20,894	0	0
Hedged funds and other alternative strategies	14,654	0	0	14,654*
International commingled trust fund	62,111	0	62,111	0
Emerging market commingled equity fund	9,535	0	9,535	0
Fixed income securities:				
U.S. fixed income	80,203	0	80,203	0
International commingled trust fund	15,179	0	15,179	0
Emerging market mutual fund	10,060	0	10,060	0
Cash and equivalents	3,407	3,407	0	0
Total Domestic Plans	299,435	107,693	177,088	14,654
Foreign Plans				
Equity securities funds	79,233	0	79,233	0
Fixed income securities funds	51,777	0	51,777	0
Diversified pooled fund	31,758	0	31,758	0
Cash and equivalents	1,343	1,343	0	0
Total Foreign Plans	164,111	1,343	162,768	0
Total	$ 463,546	109,036	339,856	14,654

* Reclassified to Level 3 to conform to current presentation.

The definition of levels within the fair value hierarchy in the tables above is included in Note P.

For domestic plans, U.S. core and small/midcap equity securities are valued based on daily market prices as quoted on national stock exchanges or in the over-the-counter market. U.S. long/short equity securities are valued monthly based on a pro-rata share of value. International equities held in a commingled trust are valued monthly based on prices as quoted on various international stock exchanges. The emerging market commingled equity fund is valued monthly based on net asset value. U.S. fixed income securities are valued daily based on bids for the same or similar securities or using net asset values. International fixed income securities held in a commingled trust are valued on a monthly basis using net asset values. The fixed income emerging market mutual fund is valued daily based on net asset value. The domestic plan commingled trusts have waiting periods for withdrawals ranging from 6 to 30 days. Hedged funds and other alternative strategies funds consist of one investment which permits withdrawals semi-annually and another investment which has a three year lock-up period and a 95 day notice following the lock-up period. For foreign plans, the equity securities funds are comprised of U.K. and foreign equity funds valued daily based on fund net asset values. Fixed income securities funds are U.K. securities valued daily at net asset values. The diversified pooled fund is valued daily at net asset value and contains a combination of Canadian and foreign equity securities, Canadian fixed income securities and cash.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

The effects of fair value measurements using significant unobservable inputs on changes in Level 3 plan assets are outlined below:

(Thousands of dollars)	Hedged Funds and Other Alternative Strategies
Total at December 31, 2011	$ 13,860
Actual return on plan assets:	
Relating to assets held at the reporting date	794
Relating to assets sold during the period	0
Purchases, sales and settlements	0
Total at December 31, 2012	14,654
Actual return on plan assets:	
Relating to assets held at the reporting date	**3,134**
Relating to assets sold during the period	**0**
Purchases, sales and settlements	**15,000**
Total at December 31, 2013	**$ 32,788**

THRIFT PLANS Most full-time employees of the Company may participate in thrift or savings plans by allotting up to a specified percentage of their base pay. The Company matches contributions at a stated percentage of each employee s allotment based on years of participation in the plans, with a maximum match of 6%. A U.K. savings plan allows eligible employees to allot a portion of their base pay to purchase Company Common stock at market value. Such employee allotments are matched by the Company. Amounts charged to expense for these U.S. and U.K. plans were $13,839,000 in 2013, $12,594,000 in 2012 and $10,725,000 in 2011.

Note K Financial Instruments and Risk Management

DERIVATIVE INSTRUMENTS Murphy uses derivative instruments to manage certain risks related to commodity prices, interest rates and foreign currency exchange rates. The use of derivative instruments for risk management is covered by operating policies and is closely monitored by the Company s senior management. The Company does not hold any derivatives for speculative purposes and it does not use derivatives with leveraged or complex features. Derivative instruments are traded primarily with creditworthy major financial institutions or over national exchanges such as the New York Mercantile Exchange (NYMEX). The Company has a risk management control system to monitor commodity price risks and any derivatives obtained to manage a portion of such risks. For accounting purposes, the Company has not designated commodity and foreign currency derivative contracts as hedges, and therefore, it recognizes all gains and losses on these derivative contracts in its Consolidated Statements of Income. As described below, certain interest rate derivative contracts were accounted for as hedges and the gain or loss associated with recording the fair value of these contracts was deferred in Accumulated Other Comprehensive Income until the anticipated transactions occur.

Commodity Purchase Price Risks The Company is subject to commodity price risk related to crude oil it will produce and sell in 2014. The Company has entered into a series of West Texas Intermediate (WTI) crude oil price swap financial contracts to hedge a portion of its Eagle Ford Shale production from January 2014 through September 2014. Under these contracts, which mature monthly, the Company will pay the average monthly price in effect and will receive the fixed contract prices. WTI open contracts at December 31, 2013 were as follows:

Dates	Volumes (barrels per day)	Swap Prices

January March 2014	20,000	$ 98.47 per barrel
April June 2014	20,000	$ 96.48 per barrel
July September 2014	7,000	$ 95.24 per barrel

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The fair value of these open commodity derivative contracts was a net asset of $716,000 at December 31, 2013. At year-end 2012, the Company was party to corn and related products derivative contracts related to formerly owned ethanol production facilities that had a fair value equal to a net asset of $2,941,000.

Foreign Currency Exchange Risks The Company is subject to foreign currency exchange risk associated with operations in countries outside the U.S. At December 31, 2013 and 2012, short-term derivative instruments were outstanding in Canada for approximately $32,300,000 and $154,000,000, respectively, to manage the currency risk associated with U.S. dollar accounts receivable balances associated with sale of Canadian crude oil in both years and a U.S. dollar intercompany accounts receivable balance at year-end 2012. The fair values of open foreign currency derivative contracts were liabilities of $26,000 at December 31, 2013 and $1,031,000 at December 31, 2012.

At December 31, 2013 and 2012, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

	December 31, 2013				December 31, 2012			
	Asset Derivatives		**Liability Derivatives**		Asset Derivatives		Liability Derivatives	
(Thousands of dollars)	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Type of Derivative Contract								
Commodity	**Accounts Receivable**	**$ 1,970**			Accounts Receivable	$ 3,043	Accounts Payable	$ 102
Foreign exchange			**Accounts Payable**	**$ 1,038**			Accounts Payable	$ 1,031

For the years ended December 31, 2013 and 2012, the gains and losses recognized in the Consolidated Statements of Income for derivative instruments not designated as hedging instruments are presented in the following table.

	Year Ended December 31, 2013		Year Ended December 31, 2012	
(Thousands of dollars)	**Location of Gain (Loss) Recognized in Income on Derivative**	**Amount of Gain (Loss) Recognized in Income on Derivative**	Location of Gain (Loss) Recognized in Income on Derivative	Amount of Gain (Loss) Recognized in Income on Derivative
Type of Derivative Contract				
Commodity	**Sale and Other Operating Revenues**	**$ 2,104**		
Commodity	**Discontinued Operations**	**(1,604)**	Discontinued Operations	$ (38,283)

Foreign exchange	**Interest and Other Income (Loss)**	**(5,162)**	Interest and Other Income (Loss)	14,156
		$ (4,662)		$ (24,127)

Interest Rate Risks In 2011 the Company entered into a series of derivative contracts known as forward starting interest rate swaps to manage interest rate risk associated with $350,000,000 of notes to be sold in 2012. These interest rate swaps matured in May 2012. Under hedge accounting rules, the Company deferred a loss on these contracts to match the payment of interest on these notes through 2022. During 2013 and 2012, $2,963,000 and

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$1,852,000 of the deferred loss on the interest rate swaps was charged to interest expense in the Consolidated Statement of Income. There was no Income Statement impact in 2011 associated with accounting for these interest rate derivative contracts. The remaining loss deferred on these matured contracts at December 31, 2013 was $24,815,000, which is recorded, net of income taxes of $8,698,000, in Accumulated Other Comprehensive Income in the Consolidated Balance Sheet. The Company expects to charge approximately $2,963,000 of this deferred loss to income in the form of interest expense during 2014.

CREDIT RISKS The Company s primary credit risks are associated with trade accounts receivable, cash equivalents and derivative instruments. Trade receivables arise mainly from sales of oil and natural gas in the U.S., Canada and Malaysia, and sale of petroleum products to a large number of customers in the United Kingdom. The credit history and financial condition of potential customers are reviewed before credit is extended, security is obtained when deemed appropriate based on a potential customer s financial condition, and routine follow-up evaluations are made. The combination of these evaluations and the large number of customers tends to limit the risk of credit concentration to an acceptable level. Cash equivalents are placed with several major financial institutions, which limit the Company s exposure to credit risk. The Company controls credit risk on derivatives through credit approvals and monitoring procedures and believes that such risks are minimal because counterparties to the majority of transactions are major financial institutions.

Note L Stockholders Equity

On December 3, 2012, the Company paid a special dividend of $2.50 per outstanding Common share to shareholders of record on November 16, 2012. This dividend totaled $486,141,000.

On October 16, 2012, the Company announced authorization of a share buyback program of up to $1.0 billion. The share repurchases could be carried out by utilization of a number of different methods, including but not limited to, open market purchases, accelerated share repurchases and negotiated block purchases, and some of the repurchases may be effected through Rule 10b5-1 plans. On October 2, 2013, the Company s Board of Directors extended the share repurchase program through April 15, 2014. Through December 31, 2013, the Company has paid $750,000,000 to repurchase shares of Common stock, and has acquired a total of 11,722,969 shares of Common stock under this buyback program. The shares acquired have been carried as Treasury Stock in the Consolidated Balance Sheet. See also Note U Subsequent Events.

Note M Earnings per Share

The following table reconciles the weighted-average shares outstanding for computation of basic and diluted income per Common share for each of the three years ended December 31, 2013. No difference existed between net income used in computing basic and diluted income per Common share for these years.

(Weighted-average shares outstanding)	**2013**	2012	2011
Basic method	**187,921,062**	193,902,335	193,409,621
Dilutive stock options	**1,350,336**	766,402	1,102,781
Diluted method	**189,271,398**	194,668,737	194,512,402

The following table reflects certain options to purchase shares of common stock that were outstanding during the three years ended December 31, 2013, but were not included in the computation of diluted EPS above because the incremental shares from assumed conversion were antidilutive.

	2013	2012	2011

Antidilutive stock options excluded from diluted shares	**1,026,900**	3,329,689	1,823,564
Weighted average price of these options	**$ 54.54**	$ 64.72	$ 69.46

Note N Other Financial Information

INVENTORIES Inventories accounted for under the LIFO method totaled $318,628,000 and $262,160,000 at December 31, 2013 and 2012, respectively, and these amounts were $268,608,000 and $571,227,000 less than

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

such inventories would have been valued using the FIFO method. These inventories are carried in Current assets held for sale in the Consolidated Balance Sheet at December 31, 2013. Significant inventory reductions occurred in 2013 and 2011 associated with the separation of the U.S. retail marketing operations and sale of the two U.S. refineries. The reduction in inventories associated with the U.S. retail marketing separation had no impact on the Company s Consolidated Statement of Income in 2013. The impact of liquidating inventories associated with the sale of the two U.S. refineries, which was mostly derived from fair value exceeding the LIFO carrying value, increased pretax income from discontinued operations by $296,185,000 in 2011.

GAIN FROM FOREIGN CURRENCY TRANSACTIONS Net gains from foreign currency transactions, including the effects of foreign currency contracts, included in the Consolidated Statements of Income were $73,732,000 in 2013, $5,092,000 in 2012 and $22,131,000 in 2011.

CASH FLOW DISCLOSURES Cash income taxes paid were $457,006,000, $566,999,000 and $938,944,000 in 2013, 2012 and 2011, respectively. Interest paid, net of amounts capitalized, was $60,501,000, $9,501,000 and $38,120,000 in 2013, 2012 and 2011, respectively.

Noncash operating working capital (increased) decreased during each of the three years ended December 31, 2013 as shown in the following table.

(Thousands of dollars)	**2013**	2012	2011
Accounts receivable	**$ 224,281**	(382,137)	90,608
Inventories	**14,166**	(94,907)	(67,560)
Prepaid expenses	**195,013**	(245,881)	9,908
Deferred income tax assets	**15,510**	(7,218)	15,914
Accounts payable and accrued liabilities	**(176,543)**	534,353	(535,788)
Current income tax liabilities	**(6,098)**	27,610	(273,118)
Net (increase) decrease in noncash operating working capital	**$ 266,329**	(168,180)	(760,036)

Note O Accumulated Other Comprehensive Income

The components of Accumulated Other Comprehensive Income (AOCI) on the Consolidated Balance Sheets at December 31, 2013 and December 31, 2012 and the changes during 2013 are presented net of taxes in the following table.

(Thousands of dollars)	Foreign Currency Translation Gains (Losses)[1]	Retirement and Postretirement Benefit Plan Adjustments[1]	Deferred Loss on Interest Rate Derivative Hedges[1]	Total[1]
Balance at December 31, 2012	$ 613,492	(186,539)	(18,052)	408,901
Components of other comprehensive income (loss):				
Before reclassifications to income	**(240,300)**	**59,145**	**0**	**(181,155)**
Reclassifications to income	**(68,000)**[2]	**10,438**[3]	**1,935**[4]	**(55,627)**
Net other comprehensive income (loss)	**(308,300)**	**69,583**	**1,935**	**(236,782)**
Balance at December 31, 2013	**$ 305,192**	**(116,956)**	**(16,117)**	**172,119**

[1] All amounts are presented net of income taxes.

[2] Reclassification is included in income from discontinued operations, net of income taxes.

[3] Reclassifications before taxes of $18,570 are included in the computation of net periodic benefit expense. Related income taxes of $8,132 are included in Income tax expense.

[4] Reclassifications before taxes of $2,963 are included in Interest expense. Related income taxes of $1,028 for the year ended December 31, 2013 are included in Income tax expense.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

At December 31, 2013, the net foreign currency translation gain of $305,192,000 was primarily related to exploration and production operations in Canada.

Note P Assets and Liabilities Measured at Fair Value

The Company carries certain assets and liabilities at fair value in its Consolidated Balance Sheet. The fair value hierarchy is based on the quality of inputs used to measure fair value, with Level 1 being the highest quality and Level 3 being the lowest quality. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs which reflect assumptions about pricing by market participants.

The fair value measurements for these assets and liabilities at December 31, 2013 and 2012 are presented in the following table.

		Fair Value Measurements at Reporting Date Using		
(Thousands of dollars)	**Fair Value at December 31, 2013**	Quoted Prices in Active Markets for Identical Assets (Liabilities) (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets				
Commodity derivative contracts	**$ 1,970**	**0**	**1,970**	**0**
Liabilities				
Nonqualified employee savings plan	**$ (13,267)**	**(13,267)**	**0**	**0**
Foreign currency exchange derivative contracts	**(1,038)**	**0**	**(1,038)**	**0**
Total	**$ (14,305)**	**(13,267)**	**(1,038)**	**0**

		Fair Value Measurements at Reporting Date Using		
(Thousands of dollars)	Fair Value at December 31, 2012	Quoted Prices in Active Markets for Identical Assets (Liabilities) (Level 1)	Significant Other Observable Input (Level 2)	Significant Unobservable Inputs (Level 3)
Assets				
Commodity derivative contracts	$ 3,043	0	3,043	0
Liabilities				
Nonqualified employee savings plan	$ (10,293)	(10,293)	0	0
Foreign currency exchange derivative contracts	(1,031)	0	(1,031)	0
Commodity derivative contracts	(102)	0	(102)	0
Total	$ (11,426)	(10,293)	(1,133)	0

The fair value of West Texas Intermediate (WTI) crude oil contracts was based on active market quotes for WTI crude oil. The fair value of foreign exchange derivative contracts was based on market quotes for similar contracts at the balance sheet date. The fair value of commodity derivative contracts for corn and wet and dried distillers grain in 2012 was determined based on market quotes for No. 2 yellow corn. The income effect of changes in fair value of crude oil derivative contracts is recorded in Sales and Other Operating Revenues in the

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Consolidated Statements of Income, while the effects of changes in fair value of foreign exchange derivative contracts is recorded in Interest and Other Income and changes in fair value of corn and distillers grain is recorded in Income from Discontinued Operations. The nonqualified employee savings plan is an unfunded savings plan through which participants seek a return via phantom investments in equity securities and/or mutual funds. The fair value of this liability was based on quoted prices for these equity securities and mutual funds. The income effect of changes in the fair value of the nonqualified employee savings plan is recorded in Selling and General Expenses.

The Company offsets certain assets and liabilities related to derivative contracts when the legal right of offset exists. There were no offsetting positions recorded at December 31, 2013. At December 31, 2012 derivative assets and liabilities which had offsetting positions are presented in the following tables.

(Thousands of dollars)	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
At December 31, 2012			
Commodity derivatives	$ 3,111	(2,169)	942

(Thousands of dollars)	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
At December 31, 2012			
Commodity derivatives	$ 2,271	(2,169)	102

All commodity derivatives noted in the above table at December 31, 2012 were corn-based contracts associated with the Company s two former U.S. ethanol plants. Net derivative assets in the table above are included in Accounts Receivable on the Consolidated Balance Sheet at December 31, 2012; likewise, net derivative liabilities in the above table are included in Accounts Payable and Accrued Liabilities on the 2012 Consolidated Balance Sheet. Separate derivative agreements existed for each of the ethanol plants. These contracts permitted net settlement and the Company generally availed itself of this right to settle net.

The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2013 and 2012. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties. The table excludes cash and cash equivalents, trade accounts receivable, trade accounts payable and accrued expenses, all of which had fair values approximating carrying amounts. The carrying value of Canadian government securities is determined based on cost plus earned interest. The fair value of current and long-term debt was estimated based on rates offered to the Company at that time for debt of the same maturities. The Company has off-balance sheet exposures relating to certain letters of credit. The fair value of these, which represents fees associated with obtaining the instruments, was nominal.

	At December 31,			
	2013		2012	
(Thousands of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value

Financial assets (liabilities):				
Canadian government securities with maturities greater than 90 days at the date of acquisition	**$ 374,842**	**375,623**	115,603	115,802
Current and long-term debt	**(2,962,812)**	**(2,822,827)**	(2,245,247)	(2,357,972)

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Note Q Commitments

The Company leases production and other facilities under operating leases. The most significant operating leases are associated with floating, production, storage and offloading facilities at the Kikeh and Azurite oil fields, production facilities at the Thunder Hawk and West Patricia fields, and certain motor fuel stations in the U.K. During each of the next five years, expected future rental payments under all operating leases are approximately $259,365,000 in 2014, $185,957,000 in 2015, $134,754,000 in 2016, $117,555,000 in 2017 and $113,585,000 in 2018. Rental expense for noncancellable operating leases, including contingent payments when applicable, was $192,482,000 in 2013, $178,292,000 in 2012 and $185,016,000 in 2011. A lease of production equipment at the Kakap field offshore Sabah, Malaysia has been accounted for as a capital lease and is included in long-term debt discussed in Note F.

The Company has entered into contracts to hire various drilling rigs and associated equipment for periods beyond December 31, 2013. These rigs will primarily be utilized for drilling operations in the Gulf of Mexico, onshore U.S. and Canada, and offshore Malaysia, Cameroon and Australia. Future commitments under these contracts, all of which expire by 2016, total $1,302,284,000. A significant portion of these costs are expected to be borne by other working interest owners as partners of the Company when the wells are drilled. These drilling costs are generally expected to be accounted for as capital expenditures as incurred during the contract periods.

The Company has operating, production handling and transportation service agreements for oil and/or natural gas operations in the U.S. and Western Canada. These agreements require minimum monthly or annual payments for processing and/or transportation charges through 2023. Future required minimum monthly payments for the next five years are $57,787,000 in 2014, $35,157,000 in 2015, $23,439,000 in 2016, $17,961,000 in 2017 and $12,792,000 in 2018. Under certain circumstances, the Company is required to pay additional amounts depending on the actual hydrocarbon quantities processed under the agreement. Costs incurred under these arrangements were $40,254,000 in 2013, $19,733,000 in 2012 and $24,791,000 in 2011.

In 2006, the Company committed to fund an educational assistance program known as the El Dorado Promise. Under this commitment, the Company will pay $5,000,000 per year for ten years through 2016 to provide scholarships for a specified amount of college expenses for eligible graduates of El Dorado High School in Arkansas. The first eight payments have been made through January 2014. The Company recorded a discounted liability of $38,700,000 in 2006 for this unconditional commitment. The liability was discounted at the Company s 10-year borrowing rate and the discounted liability increases for accretion monthly with a corresponding charge to Selling and General Expenses in the Consolidated Statement of Income. Total accretion cost was $805,000 in 2013, $1,063,000 in 2012 and $1,317,000 in 2011.

Commitments for capital expenditures were approximately $1,837,394,000 at December 31, 2013, including $706,889,000 for field development and future work commitments in Malaysia, $561,410,000 for work in the Eagle Ford Shale, $184,840,000 for costs to develop deepwater Gulf of Mexico fields, and $78,851,000, $78,000,000 and $76,150,000 for future work commitments offshore Cameroon, Equatorial Guinea and Vietnam, respectively.

Note R Contingencies

The Company s operations and earnings have been and may be affected by various forms of governmental action both in the United States and throughout the world. Examples of such governmental action include, but are by no means limited to: tax increases and retroactive tax claims; royalty and revenue sharing increases; import and export controls; price controls; currency controls; allocation of supplies of crude oil and petroleum products and other goods; expropriation of property; restrictions and preferences affecting the issuance of oil and gas or mineral leases; restrictions on drilling and/or production; laws and regulations intended for the promotion of safety and the protection and/or remediation of the environment; governmental support for other forms of energy; and laws and regulations affecting the Company s relationships with employees, suppliers, customers,

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

stockholders and others. Because governmental actions are often motivated by political considerations, may be taken without full consideration of their consequences, and may be taken in response to actions of other governments, it is not practical to attempt to predict the likelihood of such actions, the form the actions may take or the effect such actions may have on the Company.

ENVIRONMENTAL MATTERS Murphy and other companies in the oil and gas industry are subject to numerous federal, state, local and foreign laws and regulations dealing with the environment. Violation of federal or state environmental laws, regulations and permits can result in the imposition of significant civil and criminal penalties, injunctions and construction bans or delays. A discharge of hazardous substances into the environment could, to the extent such event is not insured, subject the Company to substantial expense, including both the cost to comply with applicable regulations and claims by neighboring landowners and other third parties for any personal injury and property damage that might result.

The Company currently owns or leases, and has in the past owned or leased, properties at which hazardous substances have been or are being handled. Although the Company has used operating and disposal practices that were standard in the industry at the time, hazardous substances may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes were not under Murphy s control. Under existing laws the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. Certain of these historical properties are in various stages of negotiation, investigation, and/or cleanup, and the Company is investigating the extent of any such liability and the availability of applicable defenses. The Company has retained certain liabilities related to environmental matters at formerly owned U.S. refineries that were sold in 2011. The Company also obtained insurance covering certain levels of environmental exposures related to past operations of these refineries. The Company believes costs related to these sites will not have a material adverse affect on Murphy s net income, financial condition or liquidity in a future period.

The U.S. Environmental Protection Agency (EPA) currently considers the Company to be a Potentially Responsible Party (PRP) at one Superfund site. The Company has thus far been unable to ascertain any association with the Superfund site based on its research of the facts associated with the site, and the Company has notified the EPA accordingly. Based on currently available information, the Company believes that it has no responsibility at this Superfund site. Accordingly, the Company has not recorded a liability for remedial costs at the Superfund site at December 31, 2013. The potential total cost to all parties to perform necessary remedial work at the site may be substantial. If proven to be responsible, the Company could be required to bear a pro rata share of costs attributable to nonparticipating PRPs or could be assigned additional responsibility for remediation at the site. The Company believes that its share of the ultimate costs to remediate the Superfund site will be immaterial and will not have a material adverse effect on its net income, financial condition or liquidity in a future period.

With the spin-off of Murphy s U.S. retail marketing business in 2013, the newly formed public company, Murphy USA Inc., has retained any environmental exposure associated with U.S. marketing operations. Murphy Oil has assigned its potential liability for one other Superfund site to Murphy USA Inc., and this company has accepted any potential responsibility for this site.

There is the possibility that environmental expenditures could be required at currently unidentified sites, and new or revised regulations could require additional expenditures at known sites. However, based on information currently available to the Company, the amount of future remediation costs incurred at known or currently unidentified sites is not expected to have a material adverse effect on the Company s future net income, cash flows or liquidity.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

LEGAL MATTERS Murphy and its subsidiaries are engaged in a number of other legal proceedings, all of which Murphy considers routine and incidental to its business. Based on information currently available to the Company, the ultimate resolution of environmental and legal matters referred to in this note is not expected to have a material adverse effect on the Company s net income, financial condition or liquidity in a future period.

OTHER MATTERS In the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide financial guarantees or letters of credit that may be drawn upon if the Company fails to perform under those contracts. At December 31, 2013, the Company had contingent liabilities of $129,866,000 on outstanding letters of credit. The Company has not accrued a liability in its balance sheet related to the letters of credit because it is believed that the likelihood of having these drawn is remote.

Note S Terra Nova Working Interest Redetermination

The joint agreement between the owners of the Terra Nova field, offshore Eastern Canada, required a one-time redetermination of working interests based on an analysis of reservoir quality among fault separated areas where varying ownership interests existed. Under the redetermination, which was essentially completed in 2010, the Company s working interest at Terra Nova was reduced from its original 12.0% to 10.475% effective in January 2011. The Company made a cash settlement payment to certain Terra Nova partners in January 2011 to equalize all partners interest in the field since about February 2005 related to the Company s working interest reduction. Based on the final settlement paid in 2011, the Company recorded a pretax benefit of $5,351,000 in 2011 due to the ultimate cost of the redetermination settlement being less than originally recorded. The benefit has been reflected as Redetermination of Terra Nova Working Interest in the 2011 Consolidated Statement of Income.

Note T Common Stock Issued and Outstanding

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2013 is shown below.

(Number of shares outstanding)	**2013**	2012	2011
At beginning of year	**190,641,317**	193,723,208	192,836,008
Stock options exercised*	**303,685**	482,974	615,674
Employee stock purchase and thrift plans	**16,020**	78,389	33,390
Restricted stock awards, net of forfeitures	**300,910**	224,296	238,136
Treasury shares purchased	**(7,855,419)**	(3,867,550)	0
At end of year	**183,406,513**	190,641,317	193,723,208

* Shares issued upon exercise of stock options are less than the amount reflected in Note I due to withholdings for statutory income taxes owed upon exercise.

Note U Subsequent Events

On February 5, 2014, the Company entered into a variable term, capped accelerated share repurchase (ASR) transaction with a major financial institution to repurchase a total of $250,000,000 of the Company s Common stock. Through February 28, 2014, the Company has received 4,018,000 shares under the ASR. The total number of shares to be repurchased under the ASR will be determined by references to the Rule 10b-18 volume-weighted price of the Company s Common stock, less a fixed discount. The ASR is expected to be completed within three months of the transaction. Also on February 5, 2014, the Company s Board of Directors declared a quarterly dividend of $0.3125 per share payable on March 3, 2014 to shareholders of record on February 18, 2014.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Note V Business Segments

Murphy s reportable segments are organized into geographic areas of operations. The Company s exploration and production activity is subdivided into segments for the United States, Canada, Malaysia, Republic of the Congo and all other countries. Each of these segments derives revenues primarily from the sale of crude oil and/or natural gas. The Company s management evaluates segment performance based on income from operations, excluding interest income and interest expense. Intersegment transfers of crude oil, natural gas and petroleum products are at market prices and intersegment services are recorded at cost.

The Company has announced an intention to sell its U.K. refining and marketing operations. The Company carries the assets and liabilities of the U.K. business as held for sale at December 31, 2013, and the associated results of operations are reported as discontinued operations for all periods presented.

The Company sold all of its oil and natural gas producing assets in the United Kingdom during the first half of 2013. The Company also completed the separation of its U.S. retail marketing business on August 30, 2013. In 2011, the Company sold its two U.S. oil refineries. All of these operations have also been reported as discontinued operations for all periods presented in these consolidated financial statements.

The Company has several customers that purchase a significant portion of its oil and natural gas production. During 2013, sales to Phillips 66 and affiliated companies represented approximately 17% of the Company s total sales revenue, and sales to Shell Oil and its affiliates represented approximately 14% of total sales revenue. In 2012, Shell Oil, BP and Petronas represented approximately 17%, 13% and 12%, respectively, of consolidated sales. In 2011, Shell Oil, BP and Petronas represented approximately 16%, 15% and 11%, respectively, of consolidated sales. Due to the quantity of active oil and natural gas purchasers in the markets where it produces hydrocarbons, the Company does not foresee any difficulty with selling its hydrocarbon production at fair market prices.

Information about business segments and geographic operations is reported in the following tables. For geographic purposes, revenues are attributed to the country in which the sale occurs. Corporate and other activities, including interest income, miscellaneous gains and losses, interest expense and unallocated overhead, are shown in the tables to reconcile the business segments to consolidated totals. As used in the table on the following page, Certain Long-Lived Assets at December 31 exclude investments, noncurrent receivables, deferred tax assets and goodwill and other intangible assets.

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Segment Information

(Millions of dollars)	Exploration and Production United States	Canada	Malaysia	Republic of the Congo	Other	Total
Year ended December 31, 2013						
Segment income (loss)	**$ 435.4**	**180.8**	**786.4**	**(9.0)**	**(364.8)**	**1,028.8**
Revenues from external customers	**1,803.8**	**1,144.7**	**2,280.5**	**83.5**	**0.1**	**5,312.6**
Interest income	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Interest expense, net of capitalization	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Income tax expense (benefit)	**241.6**	**57.8**	**477.7**	**(109.9)**	**(10.9)**	**656.3**
Significant noncash charges (credits)						
Depreciation, depletion, amortization	**576.3**	**374.6**	**588.2**	**0.2**	**4.3**	**1,543.6**
Accretion of asset retirement obligations	**13.5**	**16.2**	**15.0**	**4.3**	**0.0**	**49.0**
Amortization of undeveloped leases	**30.3**	**21.0**	**0.0**	**0.0**	**15.6**	**66.9**
Impairment of long-lived assets	**0.0**	**21.6**	**0.0**	**0.0**	**0.0**	**21.6**
Deferred and noncurrent income taxes	**99.6**	**26.1**	**48.1**	**0.0**	**0.0**	**173.8**
Additions to property, plant, equipment	**1,785.9**	**334.5**	**1,323.4**	**(5.7)**	**70.5**	**3,508.6**
Total assets at year-end	**4,530.0**	**4,087.8**	**6,121.0**	**51.6**	**128.8**	**14,919.2**
Year ended December 31, 2012						
Segment income (loss)	$ 168.0	208.1	894.2	(241.1)	(124.2)	905.0
Revenues from external customers	1,038.0	1,084.3	2,428.1	57.6	0.1	4,608.1
Interest income	0.0	0.0	0.0	0.0	0.0	0.0
Interest expense, net of capitalization	0.0	0.0	0.0	0.0	0.0	0.0
Income tax expense (benefit)	99.8	65.1	544.7	(64.5)	(40.1)	605.0
Significant noncash charges (credits)						
Depreciation, depletion, amortization	330.2	345.8	532.1	33.9	2.4	1,244.4
Accretion of asset retirement obligations	11.4	13.6	12.5	0.9	0.0	38.4
Amortization of undeveloped leases	71.6	29.3	0.0	0.0	28.9	129.8
Impairment of long-lived assets	0.0	0.0	0.0	200.0	0.0	200.0
Deferred and noncurrent income taxes	231.0	72.3	73.3	(0.3)	(1.2)	375.1
Additions to property, plant, equipment	1,615.9	887.2	1,426.7	(20.7)	24.7	3,933.8
Total assets at year-end	3,625.9	4,477.7	4,811.5	112.2	75.6	13,102.9
Year ended December 31, 2011						
Segment income (loss)	$ 152.7	328.0	812.7	(385.3)	(293.9)	614.2
Revenues from external customers	737.7	1,288.6*	2,045.6	148.8	24.6	4,245.3
Interest income	0.0	0.0	0.0	0.0	0.0	0.0
Interest expense, net of capitalization	0.0	0.0	0.0	0.0	0.0	0.0
Income tax expense (benefit)	86.5	135.5	434.9	16.4	7.5	680.8
Significant noncash charges (credits)						
Depreciation, depletion, amortization	183.0	326.0	357.3	87.8	1.9	956.0
Accretion of asset retirement obligations	9.9	12.5	10.6	0.5	0.3	33.8
Amortization of undeveloped leases	62.2	28.8	0.0	0.0	27.2	118.2
Impairment of long-lived assets	0.0	0.0	0.0	368.6	0.0	368.6
Deferred and noncurrent income taxes	54.2	39.6	84.6	(0.9)	(0.1)	177.4
Additions to property, plant, equipment	696.6	885.2	694.8	79.6	20.6	2,376.8
Total assets at year-end	2,227.6	3,746.8	3,826.9	257.5	74.1	10,132.9

Geographic Information

(Millions of dollars)	Certain Long-Lived Assets at December 31 United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Other	Total
2013	**$ 4,267.9**	**3,834.9**	**5,301.7**	**0.4**	**0.0**	**76.6**	**13,481.5**
2012	4,177.4	4,190.5	4,101.2	703.2	5.9	39.2	13,217.4
2011	2,953.1	3,493.4	3,154.8	694.7	133.7	52.2	10,481.9

* Reclassified to conform to current presentation.

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Segment Information (Continued)

(Millions of dollars)	Corporate and Other	Discontinued Operations	Consolidated
Year ended December 31, 2013			
Segment income (loss)	**$ (140.6)**	**235.3**	**1,123.5**
Revenues from external customers	**77.5**	**0.0**	**5,390.1**
Interest income	**3.9**	**0.0**	**3.9**
Interest expense, net of capitalization	**71.9**	**0.0**	**71.9**
Income tax expense (benefit)	**(71.7)**	**0.0**	**584.6**
Significant noncash charges (credits)			
Depreciation, depletion, amortization	**9.8**	**0.0**	**1,553.4**
Accretion of asset retirement obligations	**0.0**	**0.0**	**49.0**
Amortization of undeveloped leases	**0.0**	**0.0**	**66.9**
Impairment of long-lived assets	**0.0**	**0.0**	**21.6**
Deferred and noncurrent income taxes	**(15.7)**	**0.0**	**158.1**
Additions to property, plant, equipment	**15.5**	**8.1**	**3,532.2**
Total assets at year-end	**1,265.2**	**1,325.1**	**17,509.5**
Year ended December 31, 2012			
Segment income (loss)	$ (98.5)	164.4	970.9
Revenues from external customers	11.5	0.0	4,619.6
Interest income	6.5	0.0	6.5
Interest expense, net of capitalization	14.9	0.0	14.9
Income tax expense (benefit)	(43.5)	0.0	561.5
Significant noncash charges (credits)			
Depreciation, depletion, amortization	8.7	0.0	1,253.1
Accretion of asset retirement obligations	0.0	0.0	38.4
Amortization of undeveloped leases	0.0	0.0	129.8
Impairment of long-lived assets	0.0	0.0	200.0
Deferred and noncurrent income taxes	(32.3)	0.0	342.8
Additions to property, plant, equipment	8.2	191.8	4,133.8
Total assets at year-end	1,009.6	3,410.1	17,522.6
Year ended December 31, 2011			
Segment income (loss)	$ (75.0)	333.5	872.7
Revenues from external customers	33.4	0.0	4,278.7
Interest income	10.1	0.0	10.1
Interest expense, net of capitalization	40.7	0.0	40.7
Income tax expense (benefit)	(52.1)	0.0	628.7
Significant noncash charges (credits)			
Depreciation, depletion, amortization	8.7	0.0	964.7
Accretion of asset retirement obligations	0.0	0.0	33.8
Amortization of undeveloped leases	0.0	0.0	118.2
Impairment of long-lived assets	0.0	0.0	368.6
Deferred and noncurrent income taxes	(43.6)	0.0	133.8
Additions to property, plant, equipment	5.3	190.1	2,572.2
Total assets at year-end	790.8	3,214.4	14,138.1

Geographic Information

	Revenues from External Customers for the Year					
(Millions of dollars)	United States	Canada	Malaysia	Republic of the Congo	Other	Total
2013	**$ 1,798.5**	**1,150.2**	**2,337.5**	**83.5**	**20.4**	**5,390.1**
2012	1,038.1	1,088.4	2,415.6	57.6	19.9	4,619.6

2011	741.8	1,293.4	2,063.0	148.8	31.7	4,278.7

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

The following unaudited schedules are presented in accordance with required disclosures about Oil and Gas Producing Activities to provide users with a common base for preparing estimates of future cash flows and comparing reserves among companies. Additional background information follows concerning four of the schedules.

SCHEDULE 1 SUMMARY OF PROVED OIL RESERVES AND SCHEDULE 2 SUMMARY OF PROVED NATURAL GAS RESERVES
Reserves of crude oil, condensate, natural gas liquids, natural gas and synthetic oil are estimated by the Company s or independent engineers and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors.

Murphy s estimations for proved reserves were generated through the integration of available geoscience, engineering, and economic data, and commercially available technologies, to establish reasonable certainty of economic producibility. As defined by the SEC, reasonable certainty of proved reserves describes a high degree of confidence that the quantities will be recovered. In estimating proved reserves, Murphy uses familiar industry-accepted methods for subsurface evaluations, including performance, volumetric, and analogue based studies. Where appropriate, Murphy includes reliable geologic and engineering technology to estimate proved reserves. Reliable geologic and engineering technology is a method or combination of methods that are field tested and have demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. This integrated approach increases the quality of and confidence in Murphy s proved reserves estimates, and was utilized in certain undrilled acreage at distances greater than the directly offsetting development spacing areas, and in certain reservoirs developed with the application of improved recovery techniques. Murphy utilized a combination of 3D seismic interpretation, core analysis, wellbore log measurements, well test data, historic production and pressure data, and commercially available seismic processing and numerical reservoir simulation programs. Reservoir parameters from analogous reservoirs were used to strengthen the reserves estimates when available.

Murphy includes synthetic crude oil from its 5% interest in the Syncrude project in Alberta, Canada in its proved oil reserves. This operation involves a process of mining tar sands and converting the raw bitumen into a pipeline-quality crude. The proved reserves associated with this project are estimated through a combination of core-hole drilling and realized process efficiencies. The high-density core-hole drilling, at a spacing of less than 500 meters (proved area), provides engineering and geologic data needed to estimate the volumes of tar sand in place and its associated bitumen content. The bitumen generally constitutes approximately 10% of the total bulk tar sand that is mined. The bitumen extraction process is fairly efficient and removes about 90% of the bitumen that is contained within the tar sand. The final step of the process converts the 8.4° API bitumen into 30°-34° API crude oil. A catalytic cracking process is used to crack the long hydrocarbon chains into shorter ones yielding a final crude oil that can be shipped via pipelines. The cracking process has an efficiency ranging from 85% to 90%. Overall, it takes approximately two metric tons of oil sand to produce one barrel of synthetic crude oil. All synthetic oil volumes reported as proved reserves in Schedule 1 are the final synthetic crude oil product.

Production quantities shown are net volumes withdrawn from reservoirs. These may differ from sales quantities due to inventory changes, volumes consumed for fuel and/or shrinkage from extraction of natural gas liquids. Proved oil reserves shown in Schedule 1 include insignificant volumes of natural gas liquids.

Oil and natural gas reserves in Malaysia are associated with production sharing contracts for Blocks SK 309/311 and K. Malaysia reserves include oil and gas to be received for both cost recovery and profit provisions under the contracts. Oil and natural gas proved reserves associated with the production sharing contracts in Malaysia totaled 125.1 million barrels and 405.8 billion cubic feet, respectively, at December 31, 2013. Approximately 74.9 billion cubic feet of natural gas proved reserves in Malaysia relate to fields in Block K for which the Company expects to receive sale proceeds of approximately $0.24 per thousand cubic feet.

SCHEDULE 4 RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES Results of operations from exploration and production activities by geographic area are reported as if these activities were not part of an operation that also refines crude oil and sells refined products.

SCHEDULE 5 STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES Generally accepted accounting principles require calculation of future net cash flows using a 10% annual discount factor, an unweighted average of oil and natural gas prices in effect at the beginning of each month of the year, and year-end costs and statutory tax rates, except for known future changes such as contracted prices and legislated tax rates.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future cash flows because prices, costs and governmental policies do not remain static; appropriate discount rates may vary; and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

Schedule 5 also presents the principal reasons for change in the standardized measure of discounted future net cash flows for each of the three years ended December 31, 2013.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) Continued

Schedule 1 Summary of Proved Oil Reserves Based on Average Prices for 2010 2013

(Millions of barrels)	Total All Products	Total by product Oil	Synthetic Oil	United States Oil	Canada Oil	Canada Synthetic Oil	Malaysia Oil	United Kingdom Oil	Republic of the Congo Oil
Proved developed and undeveloped oil reserves:									
December 31, 2010	308.0	178.8	129.2	26.6	32.8	129.2	98.4	10.9	10.1
Revisions of previous estimates	21.2	16.0	5.2	2.4	3.1	5.2	8.4	8.1	(6.0)
Improved recovery	14.2	14.2	0.0	0.0	0.0	0.0	10.7	3.5	0.0
Extensions and discoveries	43.9	43.9	0.0	32.6	6.7	0.0	4.6	0.0	0.0
Production	(37.6)	(32.7)	(4.9)	(6.3)	(6.0)	(4.9)	(17.7)	(0.9)	(1.8)
December 31, 2011	349.7	220.2	129.5	55.3	36.6	129.5	104.4	21.6	2.3
Revisions of previous estimates	2.6	7.9	(5.3)	13.0	(3.4)	(5.3)	(0.4)	0.3	(1.6)
Improved recovery	7.2	7.2	0.0	0.0	0.0	0.0	7.2	0.0	0.0
Extensions and discoveries	84.0	84.0	0.0	77.3	2.9	0.0	3.8	0.0	0.0
Purchases of properties	12.5	12.5	0.0	6.5	6.0	0.0	0.0	0.0	0.0
Production	(41.2)	(36.1)	(5.1)	(9.5)	(5.3)	(5.1)	(19.3)	(1.3)	(0.7)
December 31, 2012	414.8	295.7	119.1	142.6	36.8	119.1	95.7	20.6	0.0
Revisions of previous estimates	**43.1**	**40.5**	**2.6**	**28.7**	**8.4**	**2.6**	**3.4**	**0.0**	**0.0**
Improved recovery	**27.4**	**27.4**	**0.0**	**0.0**	**0.0**	**0.0**	**27.4**	**0.0**	**0.0**
Extensions and discoveries	**79.6**	**79.6**	**0.0**	**61.1**	**0.3**	**0.0**	**18.2**	**0.0**	**0.0**
Sales of properties	**(20.4)**	**(20.4)**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**(20.4)**	**0.0**
Production	**(48.9)**	**(44.2)**	**(4.7)**	**(17.7)**	**(6.7)**	**(4.7)**	**(19.6)**	**(0.2)**	**0.0**
December 31, 2013	**495.6**	**378.6**	**117.0**	**214.7**	**38.8**	**117.0**	**125.1**	**0.0**	**0.0**
Proved developed oil reserves:									
December 31, 2010	248.3	129.2	119.1	15.8	28.6	119.1	66.5	10.9	7.4
December 31, 2011	238.5	118.0	120.5	20.8	32.6	120.5	57.2	5.1	2.3
December 31, 2012	267.7	148.6	119.1	48.0	29.5	119.1	67.0	4.1	0.0
December 31, 2013	**304.1**	**187.1**	**117.0**	**88.9**	**31.6**	**117.0**	**66.6**	**0.0**	**0.0**
Proved undeveloped oil reserves:									
December 31, 2010	59.7	49.6	10.1	10.8	4.2	10.1	31.9	0.0	2.7
December 31, 2011	111.2	102.2	9.0	34.5	4.0	9.0	47.2	16.5	0.0
December 31, 2012	147.1	147.1	0.0	94.6	7.3	0.0	28.7	16.5	0.0
December 31, 2013	**191.5**	**191.5**	**0.0**	**125.8**	**7.2**	**0.0**	**58.5**	**0.0**	**0.0**

Note: All oil reserves included in the table above are from consolidated subsidiaries and proportionately consolidated joint ventures. The Company has no proved oil reserves attributable to investees accounted for by the equity method.

2013 Comments for Proved Oil Reserves Changes

Revisions of previous estimates The positive revision for proved oil reserves in 2013 in the U.S. was attributable to better well performance in the Eagle Ford Shale area in South Texas, conversion of proved wet gas reserves to proved oil reserves that include natural gas liquids, and minor adds to several fields in the Gulf of Mexico. The positive revision for conventional oil in Canada was caused by well performance at the Hibernia and Terra Nova fields. Synthetic oil revisions were positive primarily due to revised cost recovery factors for bitumen extraction following renegotiated royalty terms with the government. Positive revisions in Malaysia were primarily attributable to well performance at Kikeh.

Improved recovery The positive effect from improved recovery in Malaysia was at the Kikeh field where waterflood has led to better than anticipated response in certain reservoirs.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)   Continued

Schedule 1   Summary of Proved Oil Reserves Based on Average Prices for 2010   2013 Continued

2013 Comments for Proved Oil Reserves Changes   Continued

Extensions and discoveries   The U.S. proved oil reserve additions were all in the Eagle Ford Shale where the Company has used reliable technology to add offset locations associated with well downspacing in certain areas. Proved oil adds in Canada were associated with extensions at Seal. Additions to oil reserves in Malaysia primarily related to four new oil fields offshore Sarawak which were put on production during the second half of 2013.

Sales of properties   The Company sold all its oil fields in the U.K. during the first half of 2013.

2012 Comments for Proved Oil Reserves Changes

Revisions of previous estimates   A positive proved oil reserves revision in 2012 in the U.S. were due to improved well performance in the Eagle Ford Shale and at the Medusa field in the Gulf of Mexico. Downward revisions for conventional oil in Canada related to a lower recovery assessment for certain heavy oil wells in the Seal area. Negative proved oil revisions for synthetic oil in Canada related to an entitlement change based on recent spending projections that increased royalties estimated to be paid to the government. Negative proved oil revisions in Republic of the Congo arose due to a combination of poor well performance on existing wells, a well that went off production in 2012, and generally uneconomic remaining future production due to oil recovery projections.

Improved recovery   The improved recovery in 2012 in Malaysia was essentially caused by better waterflood response in certain Kikeh field reservoir sands.

Extensions and discoveries   The U.S. proved oil reserves added in 2012 were primarily in the Eagle Ford Shale and were based on use of reliable technology to recognize additional offset undeveloped locations with 80 acre downspacing in certain areas of the play. The oil reserves added in Canada mostly related to additional development drilling off the East Coast at Hibernia and Terra Nova. Malaysia reserves increases primarily arose due to development drilling at fields offshore Sarawak.

Purchases of properties   Proved oil reserves added from property acquisitions in 2012 were associated with interests added at the Front Runner and Thunder Hawk fields in the U.S. Gulf of Mexico and in the Seal heavy oil area of Western Canada.

2011 Comments for Proved Oil Reserves Changes

Revisions of previous estimates   Positive proved oil reserve revisions in the U.S. in 2011 were primarily associated with better production at the Medusa field in the Gulf of Mexico. Positive revisions for Canada conventional operations were mostly attributable to better well performance at the Hibernia field, offshore Eastern Canada. Synthetic oil operations had positive reserve revisions due to a change in royalty rate. Positive revisions in Malaysia were primarily at the Kikeh field caused by production performance. Positive revisions in the U.K. were associated with the Schiehallion field due to redevelopment by its owners. The negative revision in reserves in Republic of the Congo was attributable to poor production results for wells in the Azurite field.

Improved recovery   The improved recovery in Malaysia in 2011 was primarily at Kikeh due to improved waterflood response in certain reservoir sands. U.K. reserves were at Schiehallion due to additional wells that permit better waterflood recovery.

Extensions and discoveries   The U.S. and Canadian reserves in 2011 related to the Eagle Ford Shale area and the Seal heavy oil area, respectively, where extensive drilling occurred during the year and many undeveloped locations will be drilled in upcoming years. The majority of Malaysia reserves related to the Block K Siakap North field, which was sanctioned for development by the government and Company in 2011.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) Continued

Schedule 2 Summary of Proved Natural Gas Reserves Based on Average Prices for 2010 2013

(Billions of cubic feet)	Total	United States	Canada	Malaysia	United Kingdom
Proved developed and undeveloped natural gas reserves:					
December 31, 2010	883.1	90.8	326.9	434.0	31.4
Revisions of previous estimates	12.6	(6.3)	59.4	(32.5)	(8.0)
Improved recovery	13.8	0.0	0.0	14.8	(1.0)
Extensions and discoveries	363.5	31.1	321.5	10.9	0.0
Production	(166.9)	(17.2)	(68.9)	(79.4)	(1.4)
December 31, 2011	1,106.1	98.4	638.9	347.8	21.0
Revisions of previous estimates	20.2	16.5	(37.2)	41.4	(0.5)
Improved recovery	7.2	0.0	0.0	7.2	0.0
Extensions and discoveries	173.5	107.2	25.8	40.5	0.0
Purchases of properties	9.4	7.0	2.4	0.0	0.0
Production	(179.4)	(19.4)	(79.5)	(79.3)	(1.2)
December 31, 2012	1,137.0	209.7	550.4	357.6	19.3
Revisions of previous estimates	**33.7**	**(38.6)**	**34.0**	**38.3**	**0.0**
Improved recovery	**3.2**	**0.0**	**0.0**	**3.2**	**0.0**
Extensions and discoveries	**153.4**	**33.3**	**42.5**	**77.6**	**0.0**
Sales of properties	**(19.0)**	**0.0**	**0.0**	**0.0**	**(19.0)**
Production	**(154.7)**	**(19.4)**	**(64.1)**	**(70.9)**	**(0.3)**
December 31, 2013	**1,153.6**	**185.0**	**562.8**	**405.8**	**0.0**
Proved developed natural gas reserves:					
December 31, 2010	586.0	67.0	210.1	277.5	31.4
December 31, 2011	711.6	58.2	427.1	210.5	15.8
December 31, 2012	706.0	78.8	415.8	197.3	14.1
December 31, 2013	**786.2**	**112.6**	**384.0**	**289.6**	**0.0**
Proved undeveloped natural gas reserves:					
December 31, 2010	297.1	23.8	116.8	156.5	0.0
December 31, 2011	394.5	40.2	211.8	137.3	5.2
December 31, 2012	431.0	130.9	134.6	160.3	5.2
December 31, 2013	**367.4**	**72.4**	**178.8**	**116.2**	**0.0**

Note: All natural gas reserves included in the table above are from consolidated subsidiaries and proportionately consolidated joint ventures. The Company has no proved natural gas reserves attributable to investees accounted for by the equity method.

2013 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates The U.S. natural gas proved reserves revisions in 2013 were unfavorable due to conversion of proved wet gas reserves to proved residual gas reserves. Positive revisions in Canada were mostly attributable to better well performance in the Tupper West area. Malaysia had positive gas revisions principally due to better well performance at gas fields offshore Sarawak and positive revisions due to better overall well production at the Kikeh field.

Improved recovery The reserves add in Malaysia was attributable to better waterflood response at the Kikeh field due to better overall well production.

Extensions and discoveries U.S. proved reserves of gas had adds in the Eagle Ford Shale due to additional offsets based on use of reliable technology with narrower downspacing in certain areas. The gas reserve adds in Canada were at the Tupper West and Tupper areas primarily caused by drilling activities and recognition of offset undeveloped locations. Natural gas proved reserve were added in Malaysia primarily due to initial booking of reserves of associated gas at three oil fields offshore Sarawak.

Sales of properties The Company sold all of its U.K. oil and gas fields in the first half of 2013.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) Continued

Schedule 2 Summary of Proved Natural Gas Reserves Based on Average Prices for 2010 2013 Continued

2012 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates The positive proved natural gas reserves revisions in the U.S. during 2012 were primarily caused by better well performance for certain fields in the Gulf of Mexico and in the Eagle Ford Shale. The negative revision in Canada was mostly attributable to weaker natural gas prices that unfavorably affected economical recovery at certain wells in the Montney formation in Western Canada. A positive natural gas reserves revision in Malaysia was related to better well performance and favorable entitlement effects for gas operations offshore Sarawak.

Improved recovery The improved recovery in 2012 in Malaysia was essentially caused by better waterflood response in certain Kikeh field reservoir sands.

Extensions and discoveries U.S. natural gas proved reserves added were primarily in the Eagle Ford Shale due to recognition of additional offsets from expanded use of reliable technology with 80 acre downspacing in certain areas of the play, plus the initial booking of proved gas reserves for the Dalmatian field in the Gulf of Mexico. Natural gas reserves added in Canada were primarily associated with drilling performed in the Tupper area. Reserves added in Malaysia were principally associated with development drilling operations at Sarawak gas fields.

Purchases of properties Natural gas reserves added in 2012 related to additional interests acquired during the year at the Front Runner and Thunder Hawk fields in the U.S. Gulf of Mexico and in the Seal area of Western Canada.

2011 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates Proved natural gas reserves in the U.S. had negative revisions in 2011 due to well performance being less than expected in early wells drilled in the gas-prone regions of the Eagle Ford Shale. Positive revisions in Canada were primarily at the Tupper and Tupper West areas based on better than anticipated well performance. Negative revisions in Malaysia in 2011 were primarily due to higher sales prices which effectively reduced the entitlement percentage for future production at Sarawak gas fields. Negative revisions in the U.K. were essentially caused by revised estimate of gas-cap volumes at the Mungo/Monan field.

Improved recovery The improved recovery in Malaysia in 2011 was primarily at Kikeh due to improved waterflood response in certain reservoir sands. The U.K. reserves were at Schiehallion due to additional wells that permit better waterflood recovery.

Extensions and discoveries The U.S. reserves related to the Eagle Ford Shale area where extensive drilling occurred in 2011 and many undeveloped locations will be drilled in upcoming years. Canada reserves primarily related to Tupper West and Tupper areas in British Columbia mostly due to substantial drilling programs in 2011 and extensions for additional undeveloped locations which are planned to be drilled in upcoming years. Malaysia reserves include a combination of a Sarawak gas field, where three new sand reservoirs were found to be productive and were completed, and the Block K Siakap North field, which was sanctioned for development by the government and Company in 2011.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) Continued

Schedule 3 Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

(Millions of dollars)	United States	Canada	Malaysia	United Kingdom[1]	Republic of the Congo	Other	Total
Year Ended December 31, 2013							
Property acquisition costs							
Unproved	**$ 32.4**	**0.0**	**0.0**	**0.0**	**0.0**	**3.2**	**35.6**
Proved	**13.2**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**13.2**
Total acquisition costs	**45.6**	**0.0**	**0.0**	**0.0**	**0.0**	**3.2**	**48.8**
Exploration costs[2]	**112.4**	**21.8**	**14.9**	**0.0**	**0.1**	**344.5**	**493.7**
Development costs[2]	**1,773.2**	**351.6**	**1,787.7[3]**	**8.1**	**0.0**	**19.0**	**3,939.6**
Total costs incurred	**1,931.2**	**373.4**	**1,802.6**	**8.1**	**0.1**	**366.7**	**4,482.1**
Charged to expense							
Dry hole expense	**46.1**	**32.1**	**20.7**	**0.0**	**5.6**	**158.4**	**262.9**
Geophysical and other costs	**29.1**	**0.7**	**4.6**	**0.0**	**0.2**	**137.8**	**172.4**
Total charged to expense	**75.2**	**32.8**	**25.3**	**0.0**	**5.8**	**296.2**	**435.3**
Property additions	**$ 1,856.0**	**340.6**	**1,777.3**	**8.1**	**(5.7)**	**70.5**	**4,046.8**
Year Ended December 31, 2012							
Property acquisition costs							
Unproved	$ 107.7	14.6	0.0	0.0	0.0	10.2	132.5
Proved	69.1	242.4	0.0	0.0	0.0	0.0	311.5
Total acquisition costs	176.8	257.0	0.0	0.0	0.0	10.2	444.0
Exploration costs[2]	174.5	57.0	68.8	(1.0)	51.1	97.6	448.0
Development costs[2]	1,352.7	664.5	1,433.7	46.6	22.6	1.6	3,521.7
Total costs incurred	1,704.0	978.5	1,502.5	45.6	73.7	109.4	4,413.7
Charged to expense							
Dry hole expense	32.3	8.0	26.1	(0.8)	76.2	39.3	181.1
Geophysical and other costs	19.6	2.5	1.1	(0.2)	0.6	45.4	69.0
Total charged to expense	51.9	10.5	27.2	(1.0)	76.8	84.7	250.1
Property additions	$ 1,652.1	968.0	1,475.3	46.6	(3.1)	24.7	4,163.6
Year Ended December 31, 2011							
Property acquisition costs							
Unproved	$ 233.8	18.5	0.0	0.0	0.0	27.0	279.3
Proved	0.0	0.0	0.0	0.0	23.5	0.0	23.5

Total acquisition costs	233.8	18.5	0.0	0.0	23.5	27.0	302.8
Exploration costs[2]	253.2	76.0	0.7	0.5	0.5	231.6	562.5
Development costs[2]	263.9	871.9	705.5	30.5	78.7	3.8	1,954.3
Total costs incurred	750.9	966.4	706.2	31.0	102.7	262.4	2,819.6
Charged to expense							
Dry hole expense	0.6	50.6	0.1	0.0	18.1	181.6	251.0
Geophysical and other costs	35.9	10.2	11.0	0.5	2.9	60.2	120.7
Total charged to expense	36.5	60.8	11.1	0.5	21.0	241.8	371.7
Property additions	$ 714.4	905.6	695.1	30.5	81.7	20.6	2,447.9

1 The Company has accounted for U.K. operations as discontinued operations due to the sale of these operations in the first half of 2013.
2 Includes non-cash asset retirement costs as follows:

2013							
Exploration costs	**$ 0.0**	**0.2**	**0.0**	**0.0**	**0.0**	**0.0**	**0.2**
Development costs	**70.1**	**5.9**	**95.9**	**0.0**	**0.0**	**0.0**	**171.9**
	$ 70.1	**6.1**	**95.9**	**0.0**	**0.0**	**0.0**	**172.1**
2012							
Exploration costs	$ (1.7)	0.1	0.0	0.0	0.0	0.0	(1.6)
Development costs	37.9	80.7	48.6	(11.5)	17.6	0.0	173.3
	$ 36.2	80.8	48.6	(11.5)	17.6	0.0	171.7
2011							
Exploration costs	$ 2.0	0.3	0.0	0.0	0.0	0.0	2.3
Development costs	15.8	20.1	0.3	10.8	2.1	0.0	49.1
	$ 17.8	20.4	0.3	10.8	2.1	0.0	51.4

3 Includes property cost associated with non-cash capital lease of $358.0 million at the Kakap field.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) Continued

Schedule 4 Results of Operations for Oil and Gas Producing Activities*

		Canada			Republic		
(Millions of dollars)	United States	Conven-tional	Synthetic	Malaysia	of the Congo	Other	Total
Year Ended December 31, 2013							
Revenues							
Crude oil and natural gas liquids sales	**$ 1,724.7**	**507.2**	**441.0**	**1,875.0**	**83.6**	**0.0**	**4,631.5**
Natural gas sales	**72.7**	**198.1**	**0.0**	**404.0**	**0.0**	**0.0**	**674.8**
Total oil and gas revenues	**1,797.4**	**705.3**	**441.0**	**2,279.0**	**83.6**	**0.0**	**5,306.3**
Other operating revenues	**6.4**	**(1.9)**	**0.3**	**1.5**	**(0.1)**	**0.1**	**6.3**
Total revenues	**1,803.8**	**703.4**	**441.3**	**2,280.5**	**83.5**	**0.1**	**5,312.6**
Costs and expenses							
Production expenses	**351.1**	**185.5**	**228.2**	**384.4**	**191.0**	**0.0**	**1,340.2**
Exploration costs charged to expense	**75.2**	**32.8**	**0.0**	**25.3**	**5.8**	**296.2**	**435.3**
Undeveloped lease amortization	**30.3**	**21.0**	**0.0**	**0.0**	**0.0**	**15.6**	**66.9**
Depreciation, depletion and amortization	**576.3**	**319.2**	**55.4**	**588.2**	**0.2**	**4.3**	**1,543.6**
Accretion of asset retirement obligations	**13.5**	**5.9**	**10.3**	**15.0**	**4.3**	**0.0**	**49.0**
Impairment of properties	**0.0**	**21.6**	**0.0**	**0.0**	**0.0**	**0.0**	**21.6**
Selling and general expenses	**80.4**	**25.3**	**0.9**	**3.5**	**1.1**	**59.7**	**170.9**
Total costs and expenses	**1,126.8**	**611.3**	**294.8**	**1,016.4**	**202.4**	**375.8**	**3,627.5**
	677.0	**92.1**	**146.5**	**1,264.1**	**(118.9)**	**(375.7)**	**1,685.1**
Income tax expense (benefit)	**241.6**	**19.9**	**37.9**	**477.7**	**(109.9)**	**(10.9)**	**656.3**
Results of operations	**$ 435.4**	**72.2**	**108.6**	**786.4**	**(9.0)**	**(364.8)**	**1,028.8**
Year Ended December 31, 2012							
Revenues							
Crude oil and natural gas liquids sales	$ 976.1	411.7	463.1	1,946.0	57.6	0.0	3,854.5
Natural gas sales	54.2	209.8	0.0	481.1	0.0	0.0	745.1
Total oil and gas revenues	1,030.3	621.5	463.1	2,427.1	57.6	0.0	4,599.6
Other operating revenues	7.7	(0.9)	0.6	1.0	0.0	0.1	8.5
Total revenues	1,038.0	620.6	463.7	2,428.1	57.6	0.1	4,608.1
Costs and expenses							
Production expenses	252.4	167.2	224.1	422.7	48.4	0.0	1,114.8
Exploration costs charged to expense	51.9	10.5	0.0	27.2	76.8	84.7	251.1
Undeveloped lease amortization	71.6	29.3	0.0	0.0	0.0	28.9	129.8
Depreciation, depletion and amortization	330.2	290.5	55.3	532.1	33.9	2.4	1,244.4

Accretion of asset retirement obligations	11.4	5.1	8.5	12.5	0.9	0.0	38.4
Impairment of properties	0.0	0.0	0.0	0.0	200.0	0.0	200.0
Selling and general expenses	52.7	19.7	0.9	(5.3)	3.2	48.4	119.6
Total costs and expenses	770.2	522.3	288.8	989.2	363.2	164.4	3,098.1
	267.8	98.3	174.9	1,438.9	(305.6)	(164.3)	1,510.0
Income tax expense (benefit)	99.8	25.1	40.0	544.7	(64.5)	(40.1)	605.0
Results of operations	$ 168.0	73.2	134.9	894.2	(241.1)	(124.2)	905.0

* Results exclude corporate overhead, interest and discontinued operations.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) Continued

Schedule 4 Results of Operations for Oil and Gas Producing Activities (Continued)[1]

(Millions of dollars)	United States	Canada Conven-tional	Canada Synthetic	Malaysia	Republic of the Congo	Other	Total
Year Ended December 31, 2011							
Revenues							
Crude oil and natural gas liquids sales	$ 648.8	505.6[2]	506.6[2]	1,583.0	148.8	0.0	3,392.8
Natural gas sales	71.1	280.2	0.0	461.3	0.0	0.0	812.6
Total oil and gas revenues	719.9	785.8	506.6	2,044.3	148.8	0.0	4,205.4
Other operating revenues	17.8	(3.8)	0.0	1.3	0.0	24.6	39.9
Total revenues	737.7	782.0	506.6	2,045.6	148.8	24.6	4,245.3
Costs and expenses							
Production expenses	164.8	151.2	236.1	420.6	37.6	0.0	1,010.3
Exploration costs charged to expense	36.5	60.8	0.0	11.1	21.0	241.8	371.2
Undeveloped lease amortization	62.2	28.8	0.0	0.0	0.0	27.2	118.2
Depreciation, depletion and amortization	183.0	273.9	52.1	357.3	87.8	1.9	956.0
Accretion of asset retirement obligations	9.9	4.9	7.6	10.6	0.5	0.3	33.8
Impairment of properties	0.0	0.0	0.0	0.0	368.6	0.0	368.6
Terra Nova working interest redetermination	0.0	(5.4)	0.0	0.0	0.0	0.0	(5.4)
Selling and general expenses	42.1	14.2	0.9	(1.6)	2.2	39.8	97.6
Total costs and expenses	498.5	528.4	296.7	798.0	517.7	311.0	2,950.3
	239.2	253.6	209.9	1,247.6	(368.9)	(286.4)	1,295.0
Income tax expense	86.5	79.7	55.8	434.9	16.4	7.5	680.8
Results of operations	$ 152.7	173.9	154.1	812.7	(385.3)	(293.9)	614.2

1 Results exclude corporate overhead, interest and discontinued operations.
2 Reclassified to conform to current presentation.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) Continued

Schedule 5 Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

(Millions of dollars)	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Total
December 31, 2013						
Future cash inflows	**$ 20,638.6**	**16,112.9**	**13,399.0**	**0.0**	**0.0**	**50,150.5**
Future development costs	**(3,833.9)**	**(1,882.3)**	**(1,445.3)**	**0.0**	**0.0**	**(7,161.5)**
Future production costs	**(5,244.7)**	**(7,073.0)**	**(4,490.4)**	**0.0**	**0.0**	**(16,808.1)**
Future income taxes	**(3,368.3)**	**(1,472.8)**	**(1,855.1)**	**0.0**	**0.0**	**(6,696.2)**
Future net cash flows	**8,191.7**	**5,684.8**	**5,608.2**	**0.0**	**0.0**	**19,484.7**
10% annual discount for estimated timing of cash flows	**(4,020.2)**	**(2,999.1)**	**(1,620.7)**	**0.0**	**0.0**	**(8,640.0)**
Standardized measure of discounted future net cash flows	**$ 4,171.5**	**2,685.7**	**3,987.5**	**0.0**	**0.0**	**10,844.7**
December 31, 2012						
Future cash inflows	$ 15,547.5	15,511.6	10,354.9	2,395.2	0.0	43,809.2
Future development costs	(3,731.6)	(1,815.2)	(966.9)	(273.2)	0.0	(6,786.9)
Future production costs	(3,466.6)	(7,336.4)	(3,143.4)	(738.3)	0.0	(14,684.7)
Future income taxes	(2,527.6)	(1,714.9)	(1,675.9)	(872.7)	0.0	(6,791.1)
Future net cash flows	5,821.7	4,645.1	4,568.7	511.0	0.0	15,546.5
10% annual discount for estimated timing of cash flows	(2,862.1)	(2,876.5)	(1,322.9)	(372.2)	0.0	(7,433.7)
Standardized measure of discounted future net cash flows	$ 2,959.6	1,768.6	3,245.8	138.8	0.0	8,112.8
December 31, 2011						
Future cash inflows	$ 6,105.4	18,835.5	11,037.5	2,509.5	248.6	38,736.5
Future development costs	(1,283.5)	(1,929.5)	(1,559.8)	(356.2)	0.0	(5,129.0)
Future production costs	(1,417.9)	(7,199.7)	(3,087.8)	(763.0)	(183.8)	(12,652.2)
Future income taxes	(807.2)	(2,806.8)	(2,129.7)	(869.0)	(39.7)	(6,652.4)
Future net cash flows	2,596.8	6,899.5	4,260.2	521.3	25.1	14,302.9
10% annual discount for estimated timing of cash flows	(912.0)	(3,658.7)	(1,507.4)	(304.4)	2.8	(6,379.7)
Standardized measure of discounted future net cash flows	$ 1,684.8	3,240.8	2,752.8	216.9	27.9	7,923.2

Schedule 5 continues on page F-60.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) Continued

Schedule 5 Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves Continued

Following are the principal sources of change in the standardized measure of discounted future net cash flows for the years shown.

(Millions of dollars)	**2013**	2012	2011
Net changes in prices and production costs	**$ 267.8**	(2,461.1)	3,743.4
Net changes in development costs	**(3,456.8)**	(3,860.1)	(4,113.9)
Sales and transfers of oil and gas produced, net of production costs	**(3,972.4)**	(3,493.3)	(3,273.5)
Net change due to extensions and discoveries	**4,608.9**	4,466.3	3,300.9
Net change due to purchases and sales of proved reserves	**(135.6)**	347.4	0.0
Development costs incurred	**3,326.8**	3,299.0	1,881.5
Accretion of discount	**1,109.3**	1,153.5	827.7
Revisions of previous quantity estimates	**1,646.0**	728.1	892.5
Net change in income taxes	**(662.1)**	9.8	(1,029.4)
Net increase	**2,731.9**	189.6	2,229.2
Standardized measure at January 1	**8,112.8**	7,923.2	5,694.0
Standardized measure at December 31	**$ 10,844.7**	8,112.8	7,923.2

Schedule 6 Capitalized Costs Relating to Oil and Gas Producing Activities

(Millions of dollars)	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Other	Subtotal	Synthetic Oil Canada	Total
December 31, 2013									
Unproved oil and gas properties	**$ 723.6**	**475.9**	**233.5**	**0.0**	**6.1**	**158.9**	**1,598.0**	**0.0**	**1,598.0**
Proved oil and gas properties	**5,816.9**	**4,529.9**	**7,636.6**	**0.0**	**737.8**	**0.0**	**18,721.2**	**1,493.5**	**20,214.7**
Gross capitalized costs	**6,540.5**	**5,005.8**	**7,870.1**	**0.0**	**743.9**	**158.9**	**20,319.2**	**1,493.5**	**21,812.7**
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	**(178.1)**	**(248.5)**	**(0.0)**	**(0.0)**	**(6.1)**	**(85.6)**	**(518.3)**	**(0.0)**	**(518.3)**
Proved oil and gas properties	**(2,171.1)**	**(2,006.8)**	**(2,576.4)**	**(0.0)**	**(737.8)**	**(0.0)**	**(7,492.1)**	**(417.6)**	**(7,909.7)**
Net capitalized costs	**$ 4,191.3**	**2,750.5**	**5,293.7**	**0.0**	**0.0**	**73.3**	**12,308.8**	**1,075.9**	**13,384.7**
December 31, 2012									
Unproved oil and gas properties	$ 750.0	510.9	837.0	0.0	11.8	107.4	2,217.1	0.0	2,217.1
Proved oil and gas properties	3,972.1	4,697.8	5,260.7	603.2	737.8	0.0	15,271.6	1,435.6	16,707.2
Gross capitalized costs	4,722.1	5,208.7	6,097.7	603.2	749.6	107.4	17,488.7	1,435.6	18,924.3
Accumulated depreciation, depletion and amortization									

Unproved oil and gas properties	(183.8)	(244.3)	(0.0)	(0.0)	(6.1)	(70.0)	(504.2)	(0.0)	(504.2)
Proved oil and gas properties	(1,590.6)	(1,828.8)	(2,001.8)	(397.5)	(737.8)	(0.0)	(6,556.5)	(389.6)	(6,946.1)
Net capitalized costs	$ 2,947.7	3,135.6	4,095.9	205.7	5.7	37.4	10,428.0	1,046.0	11,474.0

Note: Unproved oil and gas properties above include costs and associated accumulated amortization of properties that do not have proved reserves; these costs include mineral interests, uncompleted exploratory wells, and exploratory wells capitalized pending further evaluation.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL QUARTERLY INFORMATION (UNAUDITED)

(Millions of dollars except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Year Ended December 31, 2013					
Sales and other operating revenues	**$ 1,298.9**	**1,315.6**	**1,366.5**	**1,331.7**	**5,312.7**
Income from continuing operations before income taxes	**360.0**	**454.2**	**463.7**	**194.8**	**1,472.7**
Income from continuing operations	**182.7**	**259.9**	**265.0**	**180.5**	**888.1**
Net income	**360.6**	**402.7**	**284.8**	**75.4**	**1,123.5**
Income from continuing operations per Common share					
Basic	**0.96**	**1.38**	**1.42**	**0.98**	**4.73**
Diluted	**0.95**	**1.37**	**1.41**	**0.96**	**4.69**
Net income per Common share					
Basic	**1.89**	**2.13**	**1.52**	**0.41**	**5.98**
Diluted	**1.88**	**2.12**	**1.51**	**0.40**	**5.94**
Cash dividend per Common share	**0.3125**	**0.3125**	**0.3125**	**0.3125**	**1.25**
Market price of Common Stock[1]					
High	**63.81**	**66.09**	**71.84**	**65.55**	**71.84**
Low	**59.33**	**59.98**	**59.80**	**59.93**	**59.33**
Year Ended December 31, 2012					
Sales and other operating revenues	$ 1,149.8	1,078.0	1,083.7	1,297.1	4,608.6
Income from continuing operations before income taxes	471.6	357.0	338.9	200.5	1,368.0
Income from continuing operations	285.6	210.9	186.1	123.9	806.5
Net income	290.1	295.4	226.7	158.7	970.9
Income from continuing operations per Common share					
Basic	1.48	1.09	0.96	0.64	4.16
Diluted	1.47	1.08	0.95	0.64	4.14
Net income per Common share					
Basic	1.50	1.52	1.17	0.82	5.01
Diluted	1.49	1.52	1.16	0.82	4.99
Cash dividend per Common share	0.275	0.275	0.3125	2.8125[2]	3.675[2]
Market price of Common Stock[1]					
High	64.76	57.12	56.24	63.74	64.76
Low	55.82	43.65	48.80	54.97	43.65

1 Prices are as quoted on the New York Stock Exchange.

2 Includes special dividend of $2.50 per Common share paid on December 3, 2012.

Note: The first three quarters of 2013 and all 2012 quarters have been revised to present the results of U.K. and U.S. downstream operations as discontinued operations.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SCHEDULE II VALUATION ACCOUNTS AND RESERVES

(Millions of dollars)	Balance at January 1	Charged (Credited) to Expense	Deductions	Other*	Balance at December 31
2013					
Deducted from asset accounts:					
Allowance for doubtful accounts	**$ 6.7**	**0.4**	**(0.4)**	**(5.1)**	**1.6**
Deferred tax asset valuation allowance	**524.0**	**115.4**	**0.0**	**(5.7)**	**633.7**
2012					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 7.9	0.3	(1.5)	0.0	6.7
Deferred tax asset valuation allowance	445.8	78.2	0.0	0.0	524.0
2011					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 8.0	0.2	(0.3)	0.0	7.9
Deferred tax asset valuation allowance	305.3	140.5	0.0	0.0	445.8

* Amounts in 2013 primarily arose due to separation of Murphy USA Inc. and presentation of U.K. downstream operations as assets held for sale.

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GLOSSARY OF TERMS

3D seismic

three-dimensional images created by bouncing sound waves off underground rock formations that are used to determine the best places to drill for hydrocarbons

bitumen or oil sands

tar-like hydrocarbon-bearing substance that occurs naturally in certain areas at the Earth s surface or at relatively shallow depths and which can be recovered, processed and upgraded into a light, sweet synthetic crude oil

deepwater

offshore location in greater than 1,000 feet of water

downstream

refining and marketing operations

dry hole

an unsuccessful exploration well that is plugged and abandoned, with associated costs written off to expense

exploratory

wildcat and delineation, e.g., exploratory wells

hydrocarbons

organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products

synthetic oil

a light, sweet crude oil produced by upgrading bitumen recovered from oil sands

throughput

average amount of raw material processed in a given period by a facility

upstream

oil and natural gas exploration and production operations, including synthetic oil operation

wildcat

well drilled to target an untested or unproved geologic formation