MURPHY OIL CORP /DE
Form 10-K
February 28, 2013
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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, 2012

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ________to ________

Commission file number 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, 2012) $9,769,170,000.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2013 was 190,666,200.

Documents incorporated by reference:

Portions of the Registrant s definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 8, 2013 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 retail and wholesale gasoline marketing operations in the United States and refining and marketing operations in the United Kingdom. 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. Its operations are classified into two business activities: (1) Exploration and Production and (2) Refining and Marketing. 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 subdivided into segments for the United States and the United Kingdom. As described further in this Form 10-K, Murphy has previously announced its intention to separate its U.S. downstream business into an independent company and to sell its U.K. downstream business. Additionally, Corporate activities include interest income, interest expense, foreign exchange effects and administrative costs not allocated to the segments.

The information appearing in the 2012 Annual Report to Security Holders (2012 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 27 through 49, F-15 and F-16, F-46 through F-52 and F-54 of this Form 10-K report and on pages 5 and 6 of the 2012 Annual Report.

At December 31, 2012, Murphy had 9,185 employees, including 3,497 full-time and 5,688 part-time.

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.

During 2012, 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, Republic of the Congo, Indonesia, Suriname, Australia, Brunei, the Kurdistan region of Iraq, Cameroon, Vietnam and Equatorial Guinea by wholly owned Murphy Exploration & Production Company International (Murphy Expro International) and its subsidiaries, in Western Canada and offshore Eastern Canada by wholly owned Murphy Oil Company Ltd. (MOCL) and its subsidiaries, and in the U.K. North Sea and the Atlantic Margin by wholly owned Murphy Petroleum Limited. Murphy s crude oil and natural gas liquids production in 2012 was in the United States, Canada, Malaysia, the Republic of the Congo and the United Kingdom; its natural gas was produced and sold in the United States, Canada, Malaysia 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.

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In late 2012 the Company entered into contracts to sell its exploration and production assets in the United Kingdom; these assets sales are expected to be completed in early 2013 and the results for these 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 2012 averaged 112,591 barrels per day, an increase of 9% compared to 2011. The increase was primarily due to higher 2012 oil production in the Eagle Ford Shale area of South Texas and at the Kikeh field, offshore Sabah Malaysia. The Company s worldwide sales volume of natural gas averaged 490 million cubic feet (MMCF) per day in 2012, up 7% from 2011 levels. The higher natural gas sales volume in 2012 was primarily attributable to increased natural gas production in the Tupper area in Western Canada, where more wells were producing for a longer period in 2012 versus the prior year. Total worldwide 2012 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 194,278 barrels per day, an increase of 8% compared to 2011.

Total production in 2013 is currently expected to average about 200,000 barrels of oil equivalent per day. The projected production increase of approximately 3% in 2013 includes a 17% increase in oil and liquids volumes, partially offset by a 16% decline in natural gas volumes. The overall increase is primarily related to higher oil production in the Eagle Ford Shale area as the Company continues its drilling program in the play. Additionally, Canadian oil production is expected to rise in 2013 at Seal where additional acreage was acquired in late 2012, and at the Terra Nova field, where a maintenance program led to significant field shut-in during the second half of 2012. These higher oil volumes are expected to more than offset production declines in 2013 at other producing fields. Natural gas production will fall in 2013 primarily due to a significant reduction in development drilling activities in the Tupper area in northeast British Columbia during this period of 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 deepwater Gulf of Mexico, in the Eagle Ford Shale area of South Texas and onshore in South Louisiana. The Company produced approximately 26,100 barrels of oil per day and 53 million cubic feet of natural gas per day in the U.S. in 2012. These amounts represented 23% of the Company s total worldwide oil and 11% of worldwide natural gas production volumes. During 2012, approximately 54% of total U.S. hydrocarbon production was produced at fields in the Gulf of Mexico. The largest of these fields in the Gulf of Mexico in 2012 were Medusa and Front Runner. The Company holds a 60% interest at Medusa in Mississippi Canyon Blocks 538/582, which produced total daily oil and natural gas of about 4,300 barrels and 4 MMCF, respectively, in 2012. Production from Medusa is expected to decline in 2013 and should average 3,300 barrels of oil and about 3 MMCF of natural gas on a daily basis. At December 31, 2012, the Medusa field had total proved oil and natural gas reserves of approximately 9.2 million barrels and 9.4 billion cubic feet, respectively. Murphy has a 62.5% working interest in the Front Runner field in Green Canyon Blocks 338/339. Oil and natural gas production at Front Runner averaged about 3,900 barrels of oil per day and 4 MMCF per day in 2012. Production in 2013 at Front Runner is expected to average approximately 6,000 barrels of oil per day and 4 MMCF per day. The higher 2013 production at Front Runner is primarily due to the acquisition of additional working interest in mid-2012. Proved oil and natural gas reserves at Front Runner at year-end 2012 were 11.2 million barrels and 12.2 billion cubic feet, respectively. The Company also acquired additional working interests in the Thunder Hawk field in Mississippi Canyon Block 734 in 2012 and now holds 62.5% of this field. In 2012 oil production from this field averaged 2,800 barrels per day and 1.7 MMCF per day and in 2013 is expected to average approximately 6,000 barrels oil per day and 3.2 MMCF per day due to a new well completed in late 2012 and the higher working interest.

The Company has acquired rights to approximately 182 thousand gross acres in South Texas in the Eagle Ford Shale unconventional oil and gas play. The Company has ten active drilling rigs in the Eagle Ford in early 2013.

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The Company also has four active hydraulic fracturing teams operating in early 2013. Current plans are to drill approximately 170 wells in the play in 2013. The Company is primarily concentrating drilling efforts in the areas of the Eagle Ford where oil is the primary hydrocarbon produced. Totals for 2012 oil and natural gas production in the Eagle Ford area were approximately 13,300 barrels per day and 13 MMCF per day, respectively. On a barrel of oil equivalent basis, Eagle Ford production accounted for 44% of total U.S. production volumes in 2012. Due to ongoing drilling and infrastructure development activities, 2013 production is expected to increase to approximately 26,000 barrels of oil per day and 27 MMCF of natural gas per day. At December 31, 2012, the Company s proved reserves in the Eagle Ford Shale area totaled 113.6 million barrels of oil and 108.7 billion cubic feet of natural gas. Total proved U.S. oil and natural gas reserves at December 31, 2012 were 142.6 million barrels and 209.7 billion cubic feet, respectively.

The Company is developing the Dalmatian field located in DeSoto Canyon Blocks 4 and 48 in the Gulf of Mexico. The Company has a 70% working interest in Dalmatian, where first oil and natural gas production is anticipated in mid 2014.

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, two significant natural gas areas and light oil prospective acreage 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 2012 was about 5,300 barrels of oil per day at Hibernia and 1,700 barrels per day at Terra Nova. Hibernia production decreased slightly in 2012 due to normal field decline, while Terra Nova experienced significant downtime for maintenance during the second half of 2012. Oil production for 2013 at Hibernia and Terra Nova is anticipated to be approximately 5,500 barrels per day and 4,000 barrels per day, respectively. Total proved oil reserves at December 31, 2012 at Hibernia and Terra Nova were approximately 10.6 million barrels and 5.9 million barrels, respectively. The joint agreement between owners of Terra Nova required a one-time redetermination of working interests based on an analysis of reservoir quality among fault separated areas where varying ownership interests exist. The redetermination process was essentially completed in 2010 and the Company s working interest was reduced from 12.0% to 10.475% effective January 1, 2011.

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 2012 was about 13,800 barrels of synthetic crude oil per day and is expected to average about 14,000 barrels per day in 2013. Total proved reserves for Syncrude at year-end 2012 were 119.1 million barrels.

Daily production in 2012 in the WCSB averaged about 7,500 barrels of mostly heavy oil and about 217 MMCF of natural gas. Through 2012, the Company has acquired approximately 144 thousand net acres of mineral rights in the Montney area, including Tupper and Tupper West. Natural gas production commenced at Tupper in December 2008, while Tupper West production started up in February 2011. Through 2012, the Company has acquired 316 thousand net acres of mineral rights in the Seal area located in the Peace River oil sands area of Northwest Alberta. The Company is also conducting other activities in the WCSB outside the Seal and Tupper areas. Through 2012, the Company has acquired approximately 151 thousand net acres of land in Southern Alberta that is prospective for light oil. The Company began drilling operations on this acreage in early 2011. Several wells were expensed as dry holes during 2011 and 2012. One well was on production test in 2012 and early 2013. Additional wells are planned in 2013 to test various formations within this acreage. Through 2012, the Company has acquired approximately 166 thousand net acres of land in Northwest Alberta that is prospective for light oil and liquids-rich natural gas. The Company began drilling operations on this acreage in 2012. One well was on production test in 2012. Additional wells are planned in 2013 to test various formations within this

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acreage. Oil and natural gas daily production for 2013 in Western Canada, excluding Syncrude, is expected to be about 10,900 barrels and 151 MMCF, respectively. The increase in oil production in 2013 is primarily due to an acquisition of additional acreage in the Seal heavy oil area in late 2012 and an ongoing drilling program for the Seal property. The decrease in natural gas volumes in 2013 is primarily due to a significant reduction in development drilling at Tupper West and Tupper associated with depressed North American natural gas prices. Natural gas prices in North America have continued to be weak in early 2013. Total Western Canada proved oil and natural gas reserves at December 31, 2012, excluding Syncrude, were 20.3 million barrels and 542.5 billion cubic feet, respectively.

Malaysia

In Malaysia, the Company has majority interests in six separate production sharing contracts (PSCs). The Company serves as the operator of all these areas other than the Kakap field. The production sharing contracts cover approximately 2.79 million gross acres. Murphy has an 85% interest in discoveries made in two shallow-water blocks, SK 309 and SK 311, offshore Sarawak. In January 2010, Murphy relinquished all other acreage in Blocks SK 309 and SK 311, while retaining the acreage surrounding its producing oil and gas fields as well as areas surrounding its other discoveries, where development projects are ongoing or planned in the future. At four of these discoveries, Serendah, Patricia, South Acis and Permas, production is scheduled to start up in the second half of 2013 through a series of new offshore platforms and pipelines tying back to the Company s existing West Patricia infrastructure. About 7,400 barrels of oil per day were produced in 2012 at Blocks SK 309/311, with almost 75% of this at the West Patricia field and the remainder mostly associated with gas liquids produced at other Sarawak fields. Oil production in 2013 at fields in Blocks SK 309/311 is anticipated to total about 8,500 barrels of oil per day, including the new fields mentioned above. 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. Production from one of these discoveries, Belum, is scheduled to start in 2014. The gas sales contract allows for gross sales volumes of up to 250 MMCF per day through 2014, with an option to continue this production level for an additional seven years. In December 2012, Murphy exercised its option to extend the gas sales agreement, effectively lengthening Murphy s contract duration until September 2021. Total net natural gas sales volume offshore Sarawak was about 174 MMCF per day during 2012 (gross 243 MMCF per day). Sarawak net natural gas sales volumes are anticipated to be approximately 158 MMCF per day in 2013, with the reduction versus 2012 caused by higher planned downtime for maintenance and changes in entitlement in both blocks. Total proved reserves of oil and natural gas at December 31, 2012 for Blocks SK 309/311 were 10.3 million barrels and 284.7 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 important discovery at Kakap in 2004. An additional discovery was made in Block K at Siakap. 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 and Siakap. Total gross acreage held by the Company in Block K as of December 31, 2012 was 80,000 acres. Production volumes at Kikeh averaged 44,900 barrels of oil per day during 2012. Kikeh oil production increased in 2012 compared to the prior year due to new wells brought on production in the second half of 2012. Oil production at Kikeh is anticipated to average approximately 40,500 barrels per day in 2013. In February 2007, the Company signed a Kikeh field natural gas sales contract with PETRONAS that calls for gross sales volumes of up to 120 MMCF per day through June 2012. Gas production at Kikeh is slated to continue after 2012 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 began in late 2008, and 2012 production totaled approximately 42 MMCF per day in 2012. Daily gas production in 2013 at Kikeh is expected to average about 47 MMCF per day. The Kakap field in Block K is operated by another company. This field is being jointly developed with the Gumusut field owned by others and Murphy holds a 14% working interest in the unitized development. Kakap development activities continued during 2012 and early production occurred in late 2012, via a temporary tie-back to the Kikeh production facility. The primary Kakap

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production facility is expected to be completed in 2014, whereby oil production can be ramped up to a significantly higher volume. Kakap oil production in 2013 is anticipated to average 2,300 net barrels of oil per day. The Siakap oil discovery was made in 2009; the field will be a unitized development operated by Murphy. The field is presently under development as a tie-back to the Kikeh field and first oil production is currently anticipated in late 2013, with an average oil production volume of 1,000 barrels per day during the year. Associated gas produced at the Kakap and Siakap fields will be sold under separately negotiated contracts with PETRONAS. Total proved reserves booked in Block K as of year-end 2012 were 85.4 million barrels of oil and 72.9 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. The Company is in the process of having unproved reserves certified by a third party reservoir engineering company. Total gross acreage held by the Company at year-end 2012 in Block H was 1.40 million acres. In early 2006, the Company added a 60% interest in a PSC covering Block P, which includes 1.05 million gross acres of the previously relinquished Block K area, offshore Sabah. To date, exploratory drilling in Block P has been unsuccessful. Block P was relinquished in January 2013 except for a gas holding area of approximately 2,000 gross acres surrounding the Rempah well which can be retained until January 2018.

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.

Republic of the Congo

The Company 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) during 2012. These interests covered approximately 1.33 million gross acres with water depths ranging from 490 to 6,900 feet, and the Company operated both blocks. In 2005, Murphy made an oil discovery at Azurite Marine #1 in the southern block, MPS. The Company successfully followed up the Azurite discovery with other appraisal wells. First oil production occurred at the Azurite field in August 2009. Total oil production in 2012 averaged 2,100 barrels per day at Azurite for the Company s 50% interest. Anticipated production in 2013 is 1,500 barrels per day. Significant downward revisions were made in the last two years to reduce proved oil reserves at the Azurite field. The reserves revision in 2012 was necessary based on a significant well that went off production and a downward revision of expected oil recovery from producing wells. The reserves reduction led to an impairment charge of $200.0 million during 2012. A $368.6 million impairment charge was recorded in 2011 due to a reduction of proved oil reserves based on significantly lower recovery rates from producing oil wells. There were no proved oil reserves at the Azurite field as of December 31, 2012. In late 2010, the Company successfully negotiated an amendment to the PSA covering the MPS block. The new terms were officially approved in February 2011 and were effective retroactive to October 1, 2010. Essentially, the amendment revised terms of the PSA that allocated additional levels of crude oil production to the accounts of the Company and its non-government partners in future periods. The Company paid a bonus to Republic of the Congo in connection with the PSA amendment. A wildcat well drilled at a prospect in the MPN in late 2012 was unsuccessful. Based on this dry hole, a wildcat well drilled at Titane Marine in 2010 in the MPN block, which found accumulations of crude oil, was written off in 2012. The MPN block exploration license expired on December 30, 2012. The Company has notified the Republic of the Congo of its intent to relinquish the MPS block exploration license effective in March 2013. Thereafter, only the acreage associated with the Azurite oil field will be retained.

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Australia

The Company holds six exploration permits in Australia and serves as operator of four of them. A number of exploration wells will be drilled on the permits between 2013 and 2015. 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 this block to 100% in 2012 and subsequently farmed out a 50% working interest and operatorship. Block WA-423-P, also in the Browse Basin, was acquired in November 2008. The permit covers approximately 1.42 million gross acres with the Company holding a 40% working interest. The Company drilled an unsuccessful exploration well in late 2012 and anticipates relinquishing the entire permit in 2013. 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 will acquire 3D seismic data over this block on which its working interest has increased from 40% to 70%. 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. This block is adjacent to AC/P36 and is in the midst of a two-well exploration campaign. The permit comprises approximately 417,000 gross acres.

Indonesia

The Company currently has interests in four exploration licenses in Indonesia and serves as operator of all these concessions. 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 work commitment calls for geophysical work, 2D seismic acquisition and processing, and two exploration wells. 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. Multiple additional drilling prospects are currently being evaluated. 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 1.22 million gross acres. The three-year work commitment calls for seismic acquisition and processing, which the Company expects to begin in 2013. 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.

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. The first two exploration wells in Block CA-2 and the initial well in Block CA-1 were unsuccessful. Three successful wells were drilled in Block CA-1 in 2012. One exploratory well was drilling in Block CA-2 in early 2013 and an additional well is planned in the block later in the year.

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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 plans to purchase 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. The Company is awaiting signing of this production sharing contract, which is expected in early 2013. The Company plans to make 3D seismic purchases and perform other geological and geophysical studies in this block in 2013.

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 operates and holds a 50% interest in the block. The Central Dohuk block covers 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 s 20% non-operated interest in the Baranan block expired in 2012 and efforts to renew the license were unsuccessful.

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 June 2007, Murphy entered into a production sharing contract covering Block 37, offshore Suriname. Murphy operated this block and had a 100% working interest. Block 37 covered approximately 2.16 million gross acres and had water depths ranging from 160 to 1,000 feet. The contract provided for a six-year exploration period with two phases. Phase I had a four-year period that required the acquisition of 3D seismic and the drilling of two wells. The 3D seismic was shot in late 2008 and early 2009. The first two exploration wells were drilled in late 2010 and early 2011 and were unsuccessful. Murphy relinquished Block 37 in July 2012.

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 from Sterling Cameroon Limited (Sterling) via a farm-out agreement of the existing production sharing contract. Sterling retained a 50% non-operated interest in the block. 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 is currently in force majeure, pending the resolution of a border dispute with neighboring Equatorial Guinea. When force majeure is lifted, there will be 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.

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In October 2012, Murphy signed an agreement with Perenco Cameroon to acquire a 50% interest in the Elombo production sharing contract, immediately adjacent to the NTEM concession. The Company received government approval to acquire the acreage in December 2012. Perenco retained a 50% operating interest in the block. 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 is for three years and commenced in March 2010. Prior to the end of the initial period the Company must drill a well, which is currently planned in early 2013. The initial exploration period may be extended two times for two years each, with a one well obligation for each extension. As technical operator for deepwater drilling, Murphy plans to drill a 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 has been designated the operator. The government is expected to ratify 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 the first three years, Murphy anticipates acquiring new 3D seismic over the entire block and with already existing seismic, evaluating the potential for drilling.

United Kingdom Discontinued Operations

Murphy has produced oil and natural gas in the United Kingdom sector of the North Sea for many years. In 2012, Murphy entered into several contracts to sell all of its oil and gas properties in the U.K. The sales are expected to be completed in the first quarter 2013. Total 2012 production in the U.K. amounted to about 3,500 barrels of oil per day and 3 MMCF of natural gas per day. Total proved reserves in the U.K. at December 31, 2012 were 20.6 million barrels of oil and 19.3 billion cubic feet of natural gas.

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 selection of arbiters. 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.

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Proved Reserves

Total proved oil and natural gas reserves as of December 31, 2012 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	48.0		78.8
Canada	29.5	119.1	415.8
Malaysia	67.0		197.3
Republic of the Congo			
United Kingdom discontinued operations	4.1		14.1
Total proved developed reserves	148.6	119.1	706.0
Proved Undeveloped Reserves:			
United States	94.6		130.9
Canada	7.3		134.6
Malaysia	28.7		160.3
Republic of the Congo			
United Kingdom discontinued operations	16.5		5.2
Total proved undeveloped reserves	147.1		431.0
Total proved reserves	295.7	119.1	1,137.0

Murphy s total proved undeveloped reserves at December 31, 2012 increased 42.0 million barrels of oil equivalent (MMBOE) from a year earlier. Approximately 44.0 MMBOE of proved undeveloped reserves were converted to proved developed reserves during 2012. The majority of the proved undeveloped reserves migration to the proved developed category occurred at the Tupper, Tupper West and Eagle Ford Shale areas, as these areas had active development work ongoing during the year. The conversion of non-proved reserves to newly reported proved undeveloped reserves occurred at several areas including, but not limited to, the Tupper, Tupper West and Eagle Ford Shale areas and the Kikeh field. During 2012, there were 26.6 MMBOE of positive revisions for proved undeveloped reserves. The majority of proved undeveloped reserves additions associated with revisions of previous estimates were the result of development drilling and well performance at the Kikeh field in Malaysia and the Eagle Ford Shale in South Texas. The Company spent approximately $2.2 billion in 2012 to convert proved undeveloped reserves to proved developed reserves. The Company expects to spend about $2.2 billion in 2013, $1.9 billion in 2014 and $1.5 billion in 2015 to move currently undeveloped proved reserves to the developed category. The anticipated level of spend in 2013 includes significant drilling in several locations, including the Kikeh field and 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, 2012, proved reserves are included for several development projects that are ongoing, including natural gas developments at the Tupper West area in British Columbia and offshore Sarawak Malaysia, and an oil development at Kakap, offshore Sabah Malaysia. Total proved undeveloped reserves associated with various development projects at December 31, 2012 were approximately 219 MMBOE, which is 36% 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 2012. 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

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Kakap field oil development project has undeveloped proved reserves that make up less than 3% of the Company s total proved reserves at year-end 2012. This non-operated project will take 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. The third project that will take more than five years to develop is offshore Malaysia and makes up approximately 3% of the Company s total proved reserves at year-end 2012. 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 an Executive 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. The Company may also use independent reserves consultants to determine a portion of its proved reserves reported in this Form 10-K. At December 31, 2012, the Company used McDaniel & Associates Consultants Ltd., an independent petroleum engineering company, to prepare estimated proved oil reserves for its synthetic oil operations, which represented 29% of Murphy s total oil proved reserves. At December 31, 2012 and 2011, the Company utilized Ryder Scott Company, L.P., an independent petroleum engineering company, to prepare estimated proved oil and natural gas reserves for certain geographic areas. The total estimated proved reserves at December 31, 2012 prepared by Ryder Scott represented 4% and 1% of the Company s total proved oil and proved natural gas reserves, respectively, while at December 31, 2011, these amounts for proved oil and proved natural gas reserves were 16% and 5%, respectively. McDaniel & Associates and Ryder Scott s reports are included as Exhibits 99.9 through 99.11 to this Annual Report on Form 10-K.

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.

Larger Company offices 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. 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-48 and F-49 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, 2012 are shown on page 5 of the 2012 Annual Report. In 2012, 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 35 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.

Supplemental disclosures relating to oil and gas producing activities are reported on pages F-46 through F-54 of this Form 10-K report.

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At December 31, 2012, 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	59	47	138	121	197	168
Gulf of Mexico	13	5	1,069	654	1,082	659
Alaska	4	1	8		12	1
Total United States	76	53	1,215	775	1,291	828
Canada Onshore, excluding oil sands	70	70	754	727	824	797
Offshore	105	9	43	2	148	11
Oil sands Syncrude	96	5	160	8	256	13
Total Canada	271	84	957	737	1,228	821
Malaysia	165	137	2,627	1,619	2,792	1,756
United Kingdom	39	5	60	8	99	13
Republic of the Congo			658	329	658	329
Suriname			794	636	794	636
Australia			7,994	3,629	7,994	3,629
Indonesia			3,385	2,996	3,385	2,996
Brunei			2,934	519	2,934	519
Vietnam			4,421	2,874	4,421	2,874
Cameroon			573	286	573	286
Iraq			153	76	153	76
Spain			36	6	36	6
Totals	551	279	25,807	14,490	26,358	14,769

Certain acreage held by the Company will expire in the next three years. Scheduled expirations in 2013 include 36 thousand net acres in Block PM 311 in Malaysia; 626 thousand net acres in Block P Malaysia; 306 thousand net acres in Wokam II Indonesia; 323 thousand net acres consisting of Block MPS other than the Azurite field, offshore Republic of the Congo; 119 thousand net acres in the United States; 51 thousand net acres in Western Canada; and 19 thousand net acres in the Kurdistan region of Iraq. In 2014, 497 thousand net acres expire in South Barito Indonesia; 106 thousand net acres expire in Semai II Indonesia; 218 thousand net acres expire in Semai IV Indonesia; 569 thousand net acres expire in WA-423-P Australia; 179 thousand net acres expire in the United States; and 39 thousand net acres expire in Western Canada. In 2015, scheduled expiring acreage includes 67 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; 57 thousand net acres in the Kurdistan region of Iraq; 280 thousand net acres in Western Canada; and 59 thousand net acres in the United States.

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.

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The following table shows the number of oil and gas wells producing or capable of producing at December 31, 2012.

	Oil Wells		Gas Wells	
Country	Gross	Net	Gross	Net
United States	210	150	24	16
Canada	405	346	174	174
Malaysia	48	40	34	29
Republic of the Congo	5	3		
United Kingdom discontinued operations	36	3	23	2
Totals	704	542	255	221

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

	United States		Canada		Malaysia		United Kingdom		Other		Totals	
	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry
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
2010												
Exploratory	9.2				6.8	0.8		0.1	1.0	2.5	17.0	3.4
Development			87.0	5.0	23.6				2.5		113.1	5.0

Murphy's drilling wells in progress at December 31, 2012 are shown in the following table. The year-end well count includes wells awaiting various completion operations.

	Exploratory		Development		Total	
Country	Gross	Net	Gross	Net	Gross	Net
United States	1	1.0	74	67.5	75	68.5
Canada			6	6.0	6	6.0
Malaysia			2	1.7	2	1.7
Australia	1	0.2			1	0.2
Totals	2	1.2	82	75.2	84	76.4

Refining and Marketing

The Company has announced its intention to separate its refining and marketing ("downstream") businesses from its exploration and production business through a series of transactions. The Company's refining and marketing businesses are located in the United States and United Kingdom. The Company intends to sell its U.K. refining and marketing operations. In October 2012, the Company announced its intention to create a separate independent publicly owned U.S. downstream company via a spin-off of Murphy Oil USA, Inc. (MOUSA) to its shareholders. The separation process is expected to be completed in 2013. The sale of the U.K. business and the separation of the U.S. business are subject to inherent risks and uncertainties. Factors that could cause one or both of these forecasted events not to occur are described in Item 1A. Risk Factors of this Form 10-K.

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The U.S. business primarily consists of the sale of motor fuel and convenience merchandise through a large chain of retail stations owned and operated by Murphy (Company stations). Most of these Company stations are located at or near Walmart store sites, with the remaining Company stations located at other high traffic sites that are near major thoroughfares. The U.S. business entered the renewable fuels business and acquired an ethanol production facility in North Dakota during 2009, and also purchased an unfinished ethanol production facility in Texas in 2010 that was completed and began operations in 2011. Additionally, the U.S. operations include refined product terminals and a refined products trading business. The Company sold its U.S. petroleum refineries at Meraux, Louisiana and Superior, Wisconsin, and certain associated marketing assets in 2011. The U.K. business primarily consists of operations that refine crude oil and other feedstocks into petroleum products such as gasoline and distillates, buy and sell crude oil and refined products, and transport and market petroleum products.

MOUSA is a wholly owned subsidiary of Murphy Oil Corporation and markets its refined products through a network of Company stations, unbranded wholesale customers and bulk products customers in a 30-state area, primarily in the Southern and Midwestern United States. Murphy s Company stations are located in 23 states and are primarily located in the parking lots of Walmart Supercenters using the brand name Murphy USA®. The Company stations also include stand-alone locations using the Murphy Express brand. During 2012, Company stations sold over 3.8 billion gallons of motor fuel. At December 31, 2012, the Company marketed fuel and convenience merchandise through 1,165 Company stations. Of these Company stations, 1,015 are located on parking lots of Walmart Supercenters or other Walmart stores and 150 are stand-alone Murphy Express locations. MOUSA plans to build additional Company stations in future years, including, as announced in December 2012, over 200 new locations at existing Walmart Supercenters that are currently expected to be built over a three-year period.

Below is a table that lists the states where Murphy operates Company stations at December 31, 2012 and the number of stations in each state.

State	No. of stations	State	No. of stations	State	No. of stations
Alabama	66	Kansas	1	New Mexico	7
Arkansas	60	Kentucky	37	Ohio	42
Colorado	6	Louisiana	60	Oklahoma	50
Florida	103	Michigan	23	South Carolina	49
Georgia	79	Minnesota	7	Tennessee	80
Iowa	21	Missouri	46	Texas	247
Illinois	26	Mississippi	48	Virginia	3
Indiana	32	North Carolina	72	**Total**	**1,165**

The following table provides a history of our U.S. Company stations count during the three-year period ended December 31, 2012.

	Years Ended December 31,		
	2012	2011	2010
Number at beginning of year	**1,128**	1,099	1,048
New construction	**37**	30	51
Closed		(1)	
Number at end of year	**1,165**	1,128	1,099

The Company owns land underlying 908 of the Company stations on Walmart parking lots. No rent is payable to Walmart for the owned locations. For the remaining 104 Company stations located on Walmart property that are not owned, Murphy has master agreements that allow the Company to rent land from Walmart. The master agreements contain general terms applicable to all rental sites on Walmart property in the United States. The

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terms of the agreements range from 10-15 years at each station, with Murphy holding two successive five-year extension options at each site. The agreements permit Walmart to terminate the agreements in their entirety, or only as to affected sites, at its option for the following reasons: Murphy vacates or abandons the property; Murphy improperly transfers the rights under this agreement to another party; an agreement or a premises is taken upon execution or by process of law; Murphy files a petition in bankruptcy or becomes insolvent; Murphy fails to pay its debts as they become due; Murphy fails to pay rent or other sums required to be paid within 90 days after written notice; or Murphy fails to perform in any material way as required by the agreements. The Company also has three Murphy USA locations located near Walmart locations that are leased from other landowners. Of the 150 Murphy Express stations, 145 are on land owned by Murphy and five are leased properties.

Sales from the U.S. retail business of MOUSA represented 47.2% of Murphy s consolidated revenues in 2012, 47.6% in 2011 and 53.5% in 2010. MOUSA s share of fuel sales was approximately 2.5% of the total U.S. market during 2012.

In addition to the motor fuel sold at our Company stations, our stores carry a broad selection of snacks, beverages, tobacco products, and other non-food merchandise. Our merchandise offerings include two private label products, an isotonic drink offered in several flavors and a private label energy drink. In 2012, we purchased more than 88% of our merchandise from a single vendor, McLane s Company, Inc., a wholly owned subsidiary of Berkshire Hathaway, Inc. The following table shows certain information with respect to our merchandise sales for the last three years.

	2012	2011	2010
Merchandise sales (in millions)	**$ 2,144.3**	2,115.6	1,969.2
Merchandise sales revenue per store month	**$ 156,429**	158,144	153,530
Merchandise margin as a percentage of merchandise sales	**13.5%**	12.8%	13.1%

Refined products are supplied from seven terminals that are wholly owned and operated by MOUSA and at numerous terminals owned by others. Three of the wholly owned terminals are supplied by marine transportation and four are supplied by pipeline. MOUSA also receives products at terminals owned by others either in exchange for deliveries from the Company s terminals or by outright purchase.

MOUSA has two ethanol production facilities, one located in Hankinson, North Dakota, and one in Hereford, Texas. These renewable fuels businesses are a complement to Murphy s retail operations as the Company routinely blends ethanol in its gasoline products. The Hankinson facility was acquired in 2009 and was originally designed to produce 110 million gallons of corn-based ethanol per year. During 2012, the plant was expanded with the construction of additional distillation capacity, which brought the overall ethanol production capacity to 132 million gallons per annum. Ethanol production in 2012 totaled 124.9 million gallons at Hankinson. The Hereford facility was acquired in a unfinished state in late 2010. Construction of the facility was completed and operations commenced near the end of the first quarter of 2011. The Hereford facility is designed with production capacity of 105 million gallons of corn-based ethanol per year. Ethanol production during 2012 totaled 97.9 million gallons at Hereford. In addition to the ethanol production at each location, the Hankinson plant produces dried distillers grain with solubles (DDGS) and the Hereford plant produces wet distillers grains with solubles (WDGS), which are both sold to local farmers and other available outlets as an additional source of revenue. DDGS and WDGS are primarily used as animal feed. During 2012, the Company sold 374,000 tons of DDGS at Hankinson and 861,000 tons of WDGS at Hereford. The U.S. ethanol operations experienced much weaker operating margins during 2012 compared to the prior year. Due to expectation of continued weak margins in the future, the Company wrote down the carrying value of the Hereford, Texas plant at year-end 2012.

Murphy owns an interest in a crude oil pipeline that connects storage at the Louisiana Offshore Oil Port (LOOP) at Clovelly, Louisiana, to the formerly owned Meraux refinery. Murphy owns a 40.1% interest in the first 22 miles of this pipeline from Clovelly to Alliance, Louisiana, and 100% of the remaining 24 miles from Alliance to Meraux. After the sale of the Meraux refinery in late 2011, the Company uses this pipeline to transport crude oil for two major companies for a throughput fee.

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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. The refinery consistently performed near nameplate capacity during 2012. Murphy has announced its intention to sell the Milford Haven refinery and U.K. marketing assets.

Refinery capacities at Milford Haven, Wales at December 31, 2012 are shown in the following table.

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 2012, Murco distributed refined products in the United Kingdom from the wholly-owned Milford Haven refinery, three wholly owned terminals supplied by rail, seven terminals owned by others where products are received in exchange for deliveries from the Company s terminals and four terminals owned by others where products are purchased for delivery. At December 31, 2012, there were 230 Company stations, 229 of which were branded MURCO. The Company owns the freehold on 149 of the sites and leases the remainder. The Company also supplied 222 MURCO branded dealer stations at year-end 2012.

In 2012, MURCO owned approximately 8.3% of the refining capacity in the United Kingdom. MURCO s fuel sales represented 2.2% of the total U.K. market share in 2012.

A statistical summary of key operating and financial indicators for each of the seven years ended December 31, 2012 are reported on page 6 of the 2012 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 45 through 49.

Web site Access to SEC Reports

Our internet Web site address is http://www.murphyoilcorp.com. Information contained on our Web site is not part of this report on Form 10-K.

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

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 will 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-48 and F-49 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 during the years 2010 through 2012 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 crude oil and natural gas reservoirs. Estimates of economically recoverable crude 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.

Murphy s actual future crude 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.

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The Company s proved undeveloped reserves represent significant portions of total proved reserves. As of December 31, 2012, approximately 35% of the Company s proved oil reserves and 38% 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 page F-53 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 $94 per barrel in 2012, compared to $95 per barrel in 2011 and $80 per barrel in 2010. As an example of the impacts that oil and gas prices have on the Company s results of operations, the significant increase in oil prices in 2011 compared to the prior year favorably impacted earnings for the exploration and production business in that year. The average NYMEX natural gas sales prices were $2.83 per thousand cubic feet (MCF) in 2012, down from $4.03 per MCF in 2011 and $4.38 per MCF in 2010. This lower price for natural gas hurt the Company s profits in North America in 2012. The Company s net income is also significantly affected by changes in the margins on refining and marketing operations. As demonstrated in 2012 and 2011, 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 outside North America generally price off different oil indices (Malaysia Kikeh or Tapis and U.K. Brent), and these indices are influenced by different supply and demand forces than those that affect the U.S. WTI prices. Certain natural gas production, particularly in Sarawak Malaysia and the U.K., have been sold in recent years at a premium to average North American natural gas prices due to different pricing structures for gas in these regions. The Company cannot predict how changes in the sales prices of oil and natural gas and changes in refining and marketing margins will affect its results of operations in future periods. Except in limited cases, the Company typically does not seek to hedge any significant portion of its exposure to the effects of changing prices of crude oil, natural gas and refined products.

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 2012, significant wildcat wells were primarily drilled offshore Republic of the Congo, Malaysia, Brunei and Australia, and onshore in Kurdistan. The Company s 2013 planned exploratory drilling program includes wells offshore in the Gulf of Mexico, Cameroon, Brunei, Australia, Malaysia and Indonesia, and onshore in Western Canada.

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 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 and now expires in June 2016. 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. Outstanding notes of $350 million matured in May 2012 and were replaced with $500 million of notes that mature in May 2022. Additionally, in November 2012, the Company sold $1.5 billion of notes that mature between 2017 and 2042. 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. As an example, an economic slowdown in 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 in the Company s exploration and production operations. Murphy is a net purchaser of crude oil and other refinery feedstocks in the U.K., and also purchases refined products, particularly gasoline, needed to supply its U.S. retail marketing stations. Therefore, its most significant costs are subject to volatility of prices for these commodities. The Company also often experiences pressure on its operating and capital expenditures in periods of strong crude oil, natural gas and refined product 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.

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 2012, approximately 17% of the Company s total production was at fields operated by others, while at December 31, 2012, approximately 31% 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, 2012, approximately 26% of proved reserves, as defined by the U.S. Securities and Exchange Commission, were located in countries other than the U.S., Canada and the U.K. Certain of the reserves held outside these three 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 and regulations concerning: currency fluctuations, protection and remediation of the environment, concerns over the possibility of global warming being affected by human activity including the production and use of hydrocarbon energy, 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. 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 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 added delays in deepwater Gulf of Mexico drilling activities, additional regulations covering offshore drilling operations, and expected higher costs for future drilling operations and offshore insurance. Additional regulations, possible permitting delays and other restrictions associated with drilling and similar operations in the Gulf of Mexico are expected to have an adverse affect on the Company s, and likely many other companies , volume and 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, but the most severe storm activities usually occur in late summer, such as with Hurricanes Katrina and Rita in 2005. Other assets such as gasoline terminals and certain retail gasoline stations also lie near the Gulf of Mexico coastline and are vulnerable to storm damages. Although the Company maintains insurance for such risks as described below, 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 a series of transactions, including the intended sale of its U.K. downstream business, separation of its U.S. downstream company, and up to a $1 billion share buyback program. Factors that could cause one or more of these events not to occur include, but are not limited to, a failure to obtain necessary regulatory approvals, a failure to obtain assurances of anticipated tax treatment, 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.

If the anticipated transactions noted above are completed, Murphy will have fewer income-generating assets to service its debt.

If the separation of the Company s U.S. downstream assets is completed, Murphy will no longer have the income generated from these assets to make interest and principal payments on its debt. Similarly, if the proposed sale of

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Murphy s U.K. downstream operations is completed, the Company will no longer have the income generated from these assets to service its debt. If Murphy s remaining business is not successful as a stand-alone company, the Company may not have sufficient income 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 ($700 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.

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 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 usually 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

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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, 2012.

Item 2. PROPERTIES

Descriptions of the Company s oil and natural gas and refining and marketing properties 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-46 to F-54 and in Note D Property, Plant and Equipment beginning on page F-15.

Executive Officers of the Registrant

The age at January 1, 2013, present corporate office and length of service in office 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.

Steven A. Cossé Age 65; President and Chief Executive Officer and Member of the Executive Committee since June 2012. Mr. Cossé served as Executive Vice President from February 2005 through March 2011 and was General Counsel from August 1991 to March 2011. Mr. Cossé has been a Director of the Company since August 2011.

Roger W. Jenkins Age 51; Chief Operating Officer since June 2012. Mr. Jenkins has been Executive Vice President Exploration and Production since August 2009 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, and prior to that time, held various positions, including General Manager of the Company s exploration and production operations in Sabah, Malaysia.

Kevin G. Fitzgerald Age 57; 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.

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Thomas McKinlay Age 49; 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 61; Executive Vice President, Corporate Planning & Business Development since February 2012. Mr. Stobaugh was Senior Vice President from February 2005 to January 2012.

Walter K. Compton Age 50; Senior Vice President and General Counsel since March 2011. Mr. Compton was Vice President, Law from February 2009 to February 2011 and was Manager, Law from November 1996 to January 2009.

John W. Eckart Age 54; 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.

Mindy K. West Age 43; Vice President and Treasurer since January 2007. Ms. West was Director of Investor Relations from July 2001 through December 2006.

Kelli M. Hammock Age 41; Vice President, Administration since December 2009. Ms. Hammock was General Manager, Administration from June 2006 to November 2009.

Thomas J. Mireles Age 40; Vice President, Corporate Planning & Development since February 2012. Mr. Mireles was General Manager, Planning & Analysis from June 2010 to January 2012. He had previously served as Senior Manager, Business Development from February 2009 to May 2010 and was Manager, Business Development from January 2007 to January 2009.

John A. Moore Age 45; Secretary since March 2011. Mr. Moore was Senior Attorney from August 2005 to February 2011.

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 2,361 stockholders of record as of December 31, 2012. Information as to high and low market prices per share and dividends per share by quarter for 2012 and 2011 are reported on page F-55 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]
October 1, 2012 to October 31, 2012				
November 1, 2012 to November 30, 2012				
December 1, 2012 to December 31, 2012	3,867,550	$ 64.64[2]	3,867,550	$ 750,000,000
Total October 1, 2012 to December 31, 2012	**3,867,550**	**$ 64.64**	**3,867,550**	**$ 750,000,000**

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. On December 10, 2012, 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 will be 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 is expected to be completed no later than May 2013. Through December 31, 2012, the minimum amount of Common stock totaling 3,867,550 shares had been delivered to the Company pursuant to the ASR. Any remaining shares will be delivered to the Company upon the completion of the ASR program.

2 The average price disclosed represents the maximum price per share for the Company s Common stock to be acquired under the ASR. Any additional shares received upon completion of the ASR will reduce the average price paid for the shares acquired.

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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, 2007 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.

	2007	2008	2009	2010	2011	2012
Murphy Oil Corporation	100	53	66	92	70	80
S&P 500 Index	100	63	80	92	94	109
NYSE ARCA Oil Index	100	65	73	85	89	93

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Item 6. SELECTED FINANCIAL DATA

(Thousands of dollars except per share data)	**2012**	2011	2010	2009	2008
Results of Operations for the Year					
Sales and other operating revenues	**$ 28,616,331**	27,582,423	20,092,836	16,739,828	23,919,792
Net cash provided by continuing operations	**2,995,140**	1,959,850	2,969,072	1,740,593	2,755,970
Income from continuing operations	**964,046**	729,471	749,080	701,193	1,690,859
Net income	**970,876**	872,702	798,081	837,621	1,739,986
Per Common share diluted					
Income from continuing operations	**$ 4.95**	3.75	3.88	3.64	8.80
Net income	**4.99**	4.49	4.13	4.35	9.06
Cash dividends per Common share	**3.675**[1]	1.10	1.05	1.00	0.875
Percentage return on[2]					
Average stockholders equity	**10.5**	9.9	10.3	12.5	29.1
Average borrowed and invested capital	**9.6**	9.2	9.4	10.9	24.4
Average total assets	**6.2**	5.7	5.9	7.0	15.1
Capital Expenditures for the Year[3]					
Continuing operations					
Exploration and production	**$ 4,185,028**	2,748,008	2,023,309	1,790,163	1,896,130
Refining and marketing	**133,687**	122,301	290,090	263,413	348,476
Corporate and other	**8,077**	5,218	5,899	22,967	3,235
	4,326,792	2,875,527	2,319,298	2,076,543	2,247,841
Discontinued operations	**57,194**	68,285	128,842	130,726	116,845
	$ 4,383,986	2,943,812	2,448,140	2,207,269	2,364,686
Financial Condition at December 31					
Current ratio	**1.21**	1.22	1.21	1.55	1.51
Working capital	**$ 699,502**	622,743	619,783	1,194,087	958,818
Net property, plant and equipment	**13,011,606**	10,475,149	10,367,847	9,065,088	7,727,718
Total assets	**17,522,643**	14,138,138	14,233,243	12,756,359	11,149,098
Long-term debt	**2,245,201**	249,553	939,350	1,353,183	1,026,222
Stockholders equity	**8,942,035**	8,778,397	8,199,550	7,346,026	6,278,945
Per share	**46.91**	45.31	42.52	38.44	32.92
Long-term debt percent of capital employed[2]	**20.1**	2.8	10.3	15.6	14.0

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 presented here 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.

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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 with petroleum marketing operations in the United States and refining and marketing operations in the United Kingdom. A more detailed description of the Company s significant assets can be found in Item 1 of this Form 10-K report.

Murphy generates revenue by selling oil and natural gas production to customers in the United States, Canada, Malaysia and other countries. Additionally, the Company generates revenue by selling refined petroleum and ethanol products at hundreds of locations in the United States and the United Kingdom. The Company s revenue is highly affected by the prices of oil, natural gas and refined petroleum products that it sells. Also, because crude oil is purchased by the Company for U.K. refinery feedstocks, natural gas is purchased for fuel at its U.K. refinery, U.S. ethanol plants and at worldwide oil production facilities, and gasoline is purchased to supply its retail gasoline stations in the U.S. that are primarily located at Walmart Supercenters, the purchase prices for these commodities also have a significant effect on the Company s costs. 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, amortization of capital expenditures and expenses related to exploration and administration. Profits and generation of cash in the Company s refining and marketing operations are dependent upon achieving adequate margins, which are determined by the sales prices for refined petroleum products less the costs of purchased refinery feedstocks and gasoline and expenses associated with manufacturing, transporting and marketing these products. Murphy also incurs certain costs for general company 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 58% of the total hydrocarbons produced on an energy equivalent basis (one barrel of crude oil equals six thousand cubic feet of natural gas) by the Company in 2012. In 2013, the Company s ratio of hydrocarbon production represented by oil is expected to be approximately two-thirds oil, one-third gas, due to a combination of growing oil production and declining North American natural gas production. If the prices for crude oil and natural gas should weaken in 2013 or beyond, the Company would expect this to have an unfavorable impact on operating profits for its exploration and production business. Such lower oil and gas prices could, but may not, have a favorable impact on the Company s refining and marketing operating profits.

Worldwide oil prices in 2012 were generally comparable to 2011, while the sale prices for natural gas produced in North America was significantly weaker than the prior year. The sales price for a barrel of West Texas Intermediate (WTI) crude oil averaged $94.15 in 2012, $95.11 in 2011 and $79.61 in 2010. The NYMEX natural gas price per million British Thermal Units (MMBTU) averaged $2.83 in 2012, $4.03 in 2011 and $4.38 in 2010. While the price of WTI fell slightly in 2012, certain other benchmark oil prices, such as Dated Brent, experienced small increases during the year. Natural gas prices fell in 2012 primarily due to continued expansion in North American gas supply and secondly due to a warmer than normal winter season in 2012 in the U.S. and Canada. Gas supplies grew primarily due to a number of expanding North American unconventional gas resource plays. Worldwide oil prices were significantly higher in 2011 than 2010, but North American natural gas prices were weaker in 2011 than in the prior year. Crude oil prices rose in 2011 primarily due to a combination of recovering demand and unrest in the oil-rich Middle East and Northern Africa. While the 2011 prices of WTI crude oil rose almost 20% compared to the prior year, crude oil sold based on other worldwide benchmark prices, such as Brent and Tapis, rose even more than WTI in that year. The 2011 rise in prices of WTI crude oil, which is only used as a benchmark in North America, was held back compared to other worldwide benchmark price increases due to a somewhat temporary crude oil dislocation discount and a bit of supply/demand disparity in the continental U.S. during 2011. The disparity between crude oil and natural gas prices in North America continued to widen during both 2012 and 2011 on an energy equivalent basis due to gas production growth that exceeded demand. U.S. crude oil prices in early 2013 have been similar to 2012 average prices, while natural gas prices in North America in 2013 have thus far been slightly above the 2012 levels due to cold temperatures across much of the Northern U.S. during the early winter season.

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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)	**2012**	2011	2010
Net income	**$ 970.9**	872.7	798.1
Diluted EPS	**4.99**	4.49	4.13
Income from continuing operations	**$ 964.1**	729.5	749.1
Diluted EPS	**4.95**	3.75	3.88
Income from discontinued operations	**$ 6.8**	143.2	49.0
Diluted EPS	**0.04**	0.74	0.25

Murphy Oil s net income in 2012 increased 11% compared to 2011 primarily due to higher earnings for continuing exploration and production (E&P) operations, partially offset by lower earnings for continuing refining and marketing operations (R&M), lower income from discontinued operations, and higher net costs of Corporate activities that were not allocated to operating segments.

Net income in 2011 was 9% higher than 2010, with the improvement primarily attributable to better earnings for R&M continuing operations, higher income from discontinued operations, which was essentially attributable to strong U.S. refining results prior to sale of these assets, and lower net costs for Corporate activities. Lower E&P earnings for continuing operations in 2011, primarily associated with a large impairment charge in Republic of the Congo, somewhat offset these favorable results in other areas.

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

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 $964.1 million ($4.95 per diluted share) in 2012, up from $729.5 million ($3.75 per diluted share) in 2011. Earnings for 2012 increased primarily due to a combination of lower impairment charges, income tax benefits, higher crude oil sales volumes, lower exploration expenses and higher U.K. R&M earnings. These were partially offset by lower North American natural gas sales prices, lower U.S. retail marketing margins, and unfavorable effects of foreign exchange compared to the prior year. Net income in 2012 and 2011 included income from discontinued operations of $6.8 million ($0.04 per diluted share) and $143.2 million ($0.74 per diluted share), respectively. The stronger results for discontinued operations in 2011 were primarily associated with operating income and a net gain on disposal of two U.S. refineries (Meraux, Louisiana and Superior, Wisconsin) and associated marketing assets which were sold in 2011.

By business unit, E&P income from continuing operations improved $290.8 million in 2012, primarily due to higher crude oil production, lower impairment expense in Republic of the Congo, income tax benefits associated with exploration activities in Republic of the Congo and Suriname, and lower exploration expenses. E&P operating results were unfavorably affected in 2012 compared to the prior year by lower North American natural gas sales prices and higher expenses for production, depreciation and administration. Income from R&M continuing operations was $32.7 million lower in 2012, with the reduction mostly attributable to lower earnings, including an impairment charge, for U.S. ethanol production operations, plus lower U.S. retail fuel margins, with these more than offsetting significantly better U.K. refining margins in the current year. The net costs of corporate activities were higher by $23.5 million in 2012, mostly attributable to unfavorable effects of transactions denominated in foreign currencies. To a lesser degree, the 2012 corporate net costs were unfavorably affected by lower interest income and higher administrative expenses.

Sales and other operating revenues grew $1.0 billion in 2012 compared to 2011 due to higher crude oil sales volumes for the E&P business, plus slightly larger sales volumes for both the U.S. and U.K. R&M continuing operations. Gain (loss) on sale of assets was $23.9 million less in 2012 than 2011 because the earlier year

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included a $23.1 million gain on sale of natural gas storage assets in Spain. Interest and other operating income was unfavorable 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. The expense associated with crude oil and product purchases increased by $574.0 million in 2012 compared to 2011 primarily due to higher costs for wholesale gasoline and other motor fuels which were purchased for resale at the Company s retail fueling stations in the U.S. and U.K. Operating expenses were $162.6 million more in 2012 than 2011 due to a combination of higher oil and natural gas production costs and higher costs for U.S. retail gasoline station operations. 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. Selling and general expenses were $57.0 million more in 2012 than in 2011 primarily due to higher employee compensation and professional services costs. Depreciation, depletion and amortization expense rose $295.8 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 $107.6 million lower in 2012 than in 2011, primarily due to a smaller impairment charge in Republic of the Congo in 2012, partially offset by a writedown in the current year of the Hereford, Texas, ethanol production facility. Accretion of asset retirement obligations was $4.6 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 the most recent year. 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 $104.2 million less than 2011 primarily due to U.S. income tax benefits of $108.3 million in 2012 associated with exploration activities in Republic of the Congo and Suriname. The consolidated effective tax rate was 40.6% in 2012 compared to 51.1% 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 a combination of U.S. state income taxes, certain foreign tax rates that exceeded the U.S. 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 2012 or future years. Income from discontinued operations was $6.8 million ($0.04 per diluted share) in 2012 and $143.2 million ($0.74 per diluted share) in 2011. Income from discontinued operations in both years included operating results for oil and gas production operations in the U.K., but discontinued operations in 2011 included operating profits of $113.1 million associated with the two U.S. petroleum refineries sold in late 2011, plus an $18.7 million after-tax gain on sale of these refineries.

2011 vs. 2010 Net income in 2011 totaled $872.7 million ($4.49 per diluted share) compared to $798.1 million ($4.13 per diluted share) in 2010. Income from continuing operations was $729.5 million ($3.75 per diluted share) in 2011 compared to $749.1 million ($3.88 per diluted share) in 2010. The reduction in 2011 income from continuing operations in comparison to 2010 was primarily attributable to an impairment charge of $368.6 million in 2011 to reduce the carrying value of the Azurite oil field offshore Republic of the Congo. This was mostly offset by higher oil prices and stronger U.S. retail marketing margins in the later year. The net cost of corporate activities not allocated to the operating segments was lower in 2011 than in 2010. Net income in 2011 included income from discontinued operations of $143.2 million ($0.74 per diluted share) compared to income from discontinued operations of $49.0 million ($0.25 per diluted share) in 2010. The higher income for discontinued operations in 2011 was primarily associated with both strong operating income and a gain on sale of two U.S. refineries and associated marketing assets which were sold in 2011.

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E&P income in 2011 was $162.2 million lower than 2010, primarily attributable to the $368.6 million impairment charge at the Azurite oil field in Republic of the Congo. Other unfavorable impacts in 2011 included higher dry hole costs compared to 2010, lower crude oil sales volumes, lower North American natural gas sales prices and higher extraction costs for oil and gas produced in 2011. E&P results in 2011 benefited from a 41% higher average sales prices for crude oil produced and a 34% higher sales prices for natural gas produced offshore Sarawak, Malaysia. Income from R&M continuing operations was $59.7 million higher in 2011 compared to 2010, essentially attributable to stronger U.S. retail gasoline marketing margins of more than $0.04 per gallon and larger profits on sales of merchandise in the U.S. retail marketing business. The net costs of corporate activities were $82.9 million less in 2011 than 2010 primarily due to gains from transactions denominated in foreign currencies in 2011 compared to losses on such transactions in 2010. During 2011 the U.S. dollar generally strengthened in comparison to the Malaysian ringgit, which provided a favorable foreign currency impact to the Company s earnings due to fewer U.S. dollars being required to pay 2011 and future income taxes owed in the local currency.

Sales and operating revenues were $7.5 billion more in 2011 than 2010 primarily due to higher prices realized on crude oil production and gasoline and other refined products sold by the Company. Gain on sale of assets classified in continuing operations was $21.8 million more in 2011 than 2010 principally due to a profit on sale of gas storage assets in Spain in 2011. Interest and other income (loss) in 2011 was favorable $90.6 million compared to 2010 principally due to improved income effects from transactions denominated in foreign currencies. Additionally, the Company collected higher interest income on invested cash balances in 2011 primarily due to larger average invested balances during the year. Crude oil and product purchases expense was $6.5 billion more in 2011 than 2010 due to higher costs of crude oil feedstocks at the Milford Haven, Wales refinery, higher costs for gasoline purchased for resale in the U.S. retail marketing operations and an increase in volume of merchandise purchased for resale at U.S. retail gasoline stations. Operating expenses in 2011 were $313.3 million more than 2010 mostly due to higher costs associated with the Company s production of oil and natural gas in 2011, plus higher operating expenses at U.S. retail marketing stations, and higher power and other costs at the Milford Haven, Wales refinery. Exploration expense in 2011 was $213.3 million above 2010 primarily due to higher dry hole costs associated with unsuccessful exploratory drilling activities in Brunei, Indonesia, Canada and Suriname. Selling and general expenses rose $41.0 million in 2011 compared to 2010 primarily due to a combination of higher costs for employee compensation and professional services. Depreciation, depletion and amortization expense was down $12.4 million in 2011 mostly due to fewer barrels of oil equivalent produced in 2011 compared to 2010. Impairment of properties of $368.6 million in 2011 was attributable to a charge to reduce the net book value of the Azurite oil field to fair value. The charge was necessitated by a reduction of proved oil reserves at this field at year-end 2011. Accretion of asset retirement obligations increased $5.1 million in 2011, primarily due to future abandonment costs to be incurred on oil and gas development wells drilled in the Eagle Ford Shale and Montney areas in 2011, and higher estimated abandonment costs for existing wells in the Gulf of Mexico and offshore Malaysia and for synthetic oil operations at Syncrude in Western Canada. The income effect of the redetermination of the Company s working interest at the Terra Nova field, offshore Eastern Canada, was favorable $23.9 million in 2011 compared to 2010. The final settlement for the redetermination was made in early 2011 at a net cost to the Company that was $5.4 million less than previously estimated. The benefit from this reduced settlement payment was recognized in 2011. The net cost of $18.6 million in 2010 related to the portion of Terra Nova s operating results in 2010 that were estimated to be owed to other partners upon final settlement. Due to the redetermination process, the Company s working interest at Terra Nova was reduced from 12.0% to 10.475%. Interest expense in 2011 was $2.7 million more than 2010 primarily due to interest associated with tax reassessments in Canada in 2011. Interest capitalized to oil and gas development projects in 2011 was $3.3 million below 2010 due to cessation of interest capitalized upon commencement of production at the Tupper West area in Western Canada in the first quarter 2011. Income tax expense was $186.6 million more in 2011 than 2010 due to higher pretax income in 2011 plus higher exploration and impairment expenses in 2011 for which no tax benefit was recognizable by the Company. The effective tax rate on a consolidated basis increased from 43.5% in 2010 to 51.1% in 2011 due to a larger percentage of earnings in higher tax jurisdictions in 2011 and due to higher exploration, impairment and other expenses in foreign jurisdictions where no income tax benefits were recognized due to no assurance that these expenses would be realized in 2011 or future years to reduce taxes owed. The tax rates in both 2011 and 2010 were higher than the U.S. federal statutory rate of 35.0% due to a combination of U.S. state income taxes, certain foreign tax rates that exceeded the U.S. 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 expenses in 2011 or future years. Income from discontinued operations was $94.2 million higher in 2011 than 2010 due to stronger U.S. refining margins in 2011 prior to the sale of the refineries near the end of the third quarter of 2011. Additionally, 2011 discontinued operations included a pretax gain on sale of the two U.S. refineries of $18.7 million.

Segment Results In the following table, the Company s results of operations for the three years ended December 31, 2012, are presented by segment. More detailed reviews of operating results for the Company s exploration and production and refining and marketing activities follow the table.

(Millions of dollars)	**2012**	2011	2010
Exploration and production continuing operations			
United States	**$ 168.0**	152.7	72.7
Canada	**208.1**	328.0	213.8
Malaysia	**894.2**	812.7	659.4
Republic of the Congo	**(241.1)**	(385.3)	(77.2)
Other	**(124.2)**	(293.9)	(92.3)
	905.0	614.2	776.4
Refining and marketing continuing operations			
United States	**105.4**	223.6	165.3
United Kingdom	**52.2**	(33.3)	(34.7)
	157.6	190.3	130.6
Corporate and other	**(98.5)**	(75.0)	(157.9)
Income from continuing operations	**964.1**	729.5	749.1
Income from discontinued operations	**6.8**	143.2	49.0
Net income	**$ 970.9**	872.7	798.1

Exploration and Production Earnings from exploration and production (E&P) continuing operations were $905.0 million in 2012, $614.2 million in 2011 and $776.4 million in 2010.

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 the current year for exploration activities in Republic of the Congo and Suriname, plus higher crude oil and natural gas sales volumes and stronger crude oil sales prices in the current 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 increased 12% 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 the current year. 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

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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.

E&P income in 2011 was $162.2 million less than in 2010 primarily due to a $368.6 million impairment charge to reduce the carrying value of the Azurite oil field to fair value at year-end 2011. The 2011 period also had higher exploration expense, lower crude oil sales volumes and lower North American natural gas sales prices. However, 2011 benefited from higher oil and Sarawak natural gas sales prices and higher natural gas sales volumes. The Company s realized crude oil sales prices for continuing operations averaged $27.43 per barrel more in 2011 than 2010. North American natural gas sales prices in 2011 were $0.26 per MCF below 2010 levels, but natural gas sales prices from fields offshore Sarawak were higher in 2011 by $1.79 per MCF. Crude oil, condensate and gas liquids sales volumes from continuing operations were 21% lower in 2011 than in 2010, compared to a decrease in oil production volumes of 19% in 2011. Oil sales volumes declined more than oil production volumes during 2011 primarily due to the timing of scheduling oil sales transactions at the Kikeh field offshore Malaysia. Sales volumes at Kikeh were below production levels in 2011 due to an increase in the volume of unsold barrels at the field at year-end 2011, while in 2010, Kikeh sales volumes exceeded production. U.S. crude oil sales volumes were lower in 2011 than 2010 principally due to less production at the Thunder Hawk field in the Gulf of Mexico. Lower crude oil sales volumes in Canada in 2011 were mostly attributable to production issues and a lower Company working interest percentage in 2011 at the Terra Nova field, but this was partially offset by higher sales volumes at the Seal heavy oil field in Alberta. Crude oil sales volumes at Kikeh in 2011 fell compared to 2010 due to lower annual production in 2011 caused by well downtime for mechanical issues. Sales of crude oil and condensate increased at fields offshore Sarawak in 2011 due to higher volumes produced during the year. Crude oil sales volumes in Republic of the Congo fell in 2011 due to production decline at the Azurite field. Natural gas sales volumes for continuing operations increased 29% in 2011 and the improvement was primarily attributable to higher gas volumes produced during 2011 at the Tupper West area in Western Canada following start-up in the first quarter of the year. Natural gas sales volumes also improved in 2011 at the Tupper area in Canada and at fields offshore Sarawak; both of these areas had active development programs during 2011. Natural gas sales volumes were lower during 2011 at the Kikeh field principally due to less volumes produced because of mechanical issues with wells.

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-51 and F-52 of this Form 10-K report. Average daily production and sales rates and weighted average sales prices are shown on page 5 of the 2012 Annual Report.

A summary of oil and gas revenues, including intersegment sales that are eliminated in the consolidated financial statements, is presented in the following table.

(Millions of dollars)	**2012**	2011	2010
United States Oil and gas liquids	**$ 976.1**	648.8	557.6
Natural gas	**54.2**	71.1	87.0
Canada Conventional oil and gas liquids	**411.7**	505.6	388.6
Synthetic oil	**463.1**	506.6	378.6
Natural gas	**209.8**	280.2	132.1
Malaysia Oil and gas liquids	**1,946.0**	1,583.0	1,531.1
Natural gas	**481.1**	461.3	307.1
Republic of the Congo oil	**57.6**	148.8	156.7
Total oil and gas revenues	**$ 4,599.6**	4,205.4	3,538.8

The Company s total crude oil, condensate and natural gas liquids production averaged 112,591 barrels per day in 2012, compared to 103,160 barrels per day in 2011 and 126,927 barrels per day in 2010.

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United States crude oil production averaged 26,090 barrels per day in 2012, an annual record for the Company in the U.S., and an increase from 17,148 barrels per day in 2011. The U.S. increase was primarily attributable to an ongoing development drilling program in the Eagle Ford Shale area in South Texas. Heavy oil production in the Western Canada Sedimentary Basin 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 in the U.K. 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 at Mungo/Monan. Expected sales of all U.K. oil and natural gas operations in early 2013 led the Company to report these U.K. E&P activities as discontinued operations for all periods presented in the consolidated financial statements.

United States oil production decreased from 20,114 barrels per day in 2010 to 17,148 barrels per day in 2011 with the lower volumes mostly caused by field decline at Thunder Hawk that was primarily due to a delay in development drilling operations in 2010 and 2011 following the Macondo incident in April 2010. The production decline at Thunder Hawk was partially offset by higher oil volumes produced in 2011 at the Eagle Ford Shale area in South Texas. Production of heavy oil in Western Canada was 7,264 barrels per day in 2011, up from 5,988 barrels per day in 2010, primarily due to ongoing drilling operations at the Seal area in Alberta. Oil production offshore Canada fell from 11,497 barrels per day in 2010 to 9,204 barrels per day in 2011 primarily due to field decline at Terra Nova and a reduction of the Company s working interest at this field from 12.0% in 2010 to 10.475% in 2011. Synthetic oil operations at Syncrude had net production of 13,498 barrels per day in 2011, up from 13,273 barrels per day in 2010, with the increase caused by a lower royalty rate in 2011 due to higher costs incurred for the operations. Oil production in Malaysia decreased from 66,897 barrels per day in 2010 to 48,551 barrels per day in 2011, primarily due to lower production at the Kikeh field. Mechanical issues at Kikeh led to certain wells being down for a portion of 2011. Oil production in Malaysia was favorably affected in 2011 by higher condensate and other gas liquids produced at gas fields offshore Sarawak. The Azurite field offshore Republic of the Congo averaged 4,989 barrels per day in 2011, down from 5,820 barrels per day in 2010 due to faster than expected well decline. Oil production from discontinued operations in the U.K. was 2,423 barrels per day in 2011, down from 3,295 barrels per day in 2010, with the decline primarily due to more downtime at the Schiehallion and Mungo/Monan fields during the later year.

Worldwide sales of natural gas were a Company record 490.1 million cubic feet (MMCF) per day in 2012, after averaging 457.4 MMCF per day in 2011 and 356.8 MMCF per day in 2010.

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 production in the Eagle Ford Shale area more than offset declines at fields in the Gulf of Mexico. Natural gas volumes in Western 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 177.0 MMCF per day in 2011. Gas sales at the Kikeh field averaged 42.4 MMCF per day in 2012, up from 40.5 MMCF per day 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.

Natural gas production in the U.S. averaged 47.2 MMCF per day in 2011, compared to 53.0 MMCF per day in 2010. The lower volume in 2011 was primarily attributable to the Thunder Hawk field where production declined during 2011 due to delay in development drilling operations following the Macondo incident in April 2010.

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Natural gas production in Canada rose from 85.6 MMCF per day in 2010 to 188.8 MMCF per day in 2011 primarily due to start up of production at the Tupper West area in Western Canada in the first quarter 2011. Gas sales volumes also increased in 2011 at the nearby Tupper area due to development drilling activities during the year. Natural gas production in Malaysia rose to 217.4 MMCF per day in 2011 compared to 212.7 MMCF per day in 2010. Natural gas sales volumes during 2011 at Sarawak and Kikeh averaged 176.9 MMCF per day and 40.5 MMCF per day, respectively. Gas sales volumes rose 22.4 MMCF per day at Sarawak in 2011 due to higher demand from the local purchaser, while Kikeh gas volumes fell 17.7 MMCF per day in 2011 due to lower demand and wells down for mechanical repairs for a portion of the year. Natural gas production from discontinued operations in the U.K. fell from 5.5 MMCF per day in 2010 to 3.9 MMCF per day in 2011 primarily due to more downtime for repairs at the Amethyst field during 2011.

The Company s average worldwide realized sales price for crude oil, condensate and gas liquids from continuing operations was $95.58 per barrel in 2012 compared to $94.18 per barrel in 2011 and $66.75 per barrel in 2010.