

MURPHY OIL CORP /DE
Form 10-K
February 28, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2011

OR

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

Commission file number 1-8590

MURPHY OIL CORPORATION

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of

71-0361522
(I.R.S. Employer

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incorporation or organization) 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	New York Stock Exchange

Preferred Stock Purchase Rights

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

None

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

Large accelerated filer <input checked="" type="checkbox"/>	Accelerated filer <input type="checkbox"/>
Non-accelerated filer <input type="checkbox"/>	Smaller reporting company <input type="checkbox"/>

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

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, 2011) \$12,706,062,000.

Number of shares of Common Stock, \$1.00 Par Value, outstanding at January 31, 2012 was 193,877,158.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 9, 2012 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 six geographic segments, including the United States, Canada, Malaysia, the United Kingdom, 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. Additionally, Corporate activities include interest income, interest expense, foreign exchange effects and administrative costs not allocated to the segments.

The information appearing in the 2011 Annual Report to Security Holders (2011 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 24 through 46, F-17 and F-18, F-46 through F-52 and F-54 of this Form 10-K report and on pages 5 and 6 of the 2011 Annual Report.

At December 31, 2011, Murphy had 8,610 employees, including 3,176 full-time and 5,434 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 2011, 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 and the Kurdistan region of Iraq 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 2011 was in the United States, Canada, Malaysia, the United Kingdom and Republic of the Congo; 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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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 2011 averaged 103,160 barrels per day, a decrease of 19% compared to 2010. The decrease was primarily due to lower 2011 oil production at the Kikeh field, offshore Sabah Malaysia, where several wells were shut-in for a portion of the year for well work due to sand production issues. The Company's worldwide sales volume of natural gas averaged 457 million cubic feet (MMCF) per day in 2011, up 28% from 2010 levels. The higher natural gas sales volume in 2011 was primarily attributable to increased natural gas production in the Montney area of Western Canada, where the Company's Tupper West area commenced gas production in early 2011 and where further development operations led to higher gas production at Tupper, and at fields offshore Sarawak Malaysia. Total worldwide 2011 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 179,388 barrels per day, a decrease of 4% compared to 2010.

Total production in 2012 is currently expected to average about 200,000 barrels of oil equivalent per day. The projected production increase of approximately 11% in 2012 is primarily related to higher natural gas production at the Tupper West area in Western Canada due to continued drilling, higher oil production at Kikeh following the well work program and additional field development operations, and higher oil and gas volumes produced in the Eagle Ford Shale area of South Texas as the Company continues to ramp-up its drilling program in the area. These volumes are expected to more than offset production declines in 2012 at other producing fields.

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 17,100 barrels of oil per day and 47 million cubic feet of natural gas per day in the U.S. in 2011. These amounts represented 17% of the Company's total worldwide oil and 10% of worldwide natural gas production volumes. During 2011, approximately 45% of total U.S. hydrocarbon production was produced at two operated Gulf of Mexico fields—Thunder Hawk and Medusa. The Company holds a 60% interest at Medusa in Mississippi Canyon Blocks 538/582, which produced total daily oil and natural gas of about 6,000 barrels and 6 MMCF, respectively, in 2011. Production from Medusa is expected to continue to decline in 2012 and should average 4,300 barrels of oil and about 4 MMCF of natural gas on a daily basis. At December 31, 2011, the Medusa field had total proved oil and natural gas reserves of approximately 5.8 million barrels and 5.9 billion cubic feet, respectively. Murphy has a 37.5% working interest in the Thunder Hawk field in Mississippi Canyon Block 734. Oil and natural gas production at Thunder Hawk averaged about 3,800 barrels of oil per day and 4 MMCF per day in 2011. Production in 2012 at Thunder Hawk is expected to average approximately 3,200 barrels of oil per day and 3 MMCF per day. The lower 2012 production at Thunder Hawk is due to well decline and a delay in performing drilling operations caused by permitting issues following the Macondo incident in 2010. Proved oil and natural gas reserves at Thunder Hawk at year-end 2011 were 3.3 million barrels and 4.0 billion cubic feet, respectively.

The Company has acquired rights to significant acreage in South Texas in the Eagle Ford Shale unconventional oil and gas play. The Company has eight active drilling rigs in the Eagle Ford in early 2012, with plans to exit 2012 with ten to twelve rigs in operation. Current plans are to drill approximately 130 wells in the play in 2012. The Company is primarily concentrating drilling efforts in the areas of the Eagle Ford where oil is the primary hydrocarbon produced. Lower natural gas price realization has caused the Company's drilling in the gas-prone areas to be limited to acreage where drilling is necessary to retain leases. Totals for 2011 oil and natural gas production in the Eagle Ford area were approximately 3,200 barrels per day and 3.3 MMCF per day, respectively. Due to ongoing drilling and infrastructure development activities, 2012 production is expected to be approximately 12,000 barrels of oil per day and 20 billion cubic feet of natural gas per day. At December 31, 2011, the Company's proved reserves in the Eagle Ford Shale area totaled 35.7 million barrels of oil and 38.2 billion cubic feet of natural gas. Total proved U.S. oil and natural gas reserves at December 31, 2011 were 55.3 million barrels and 98.4 billion cubic feet, respectively.

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Subsequent to the Macondo incident in April 2010, the process for obtaining drilling and other operational permits in the Gulf of Mexico has been extended significantly. The changes to the permitting process, as well as operational procedures, are expected to continue to cause delays and add more expense associated with drilling operations in the Gulf of Mexico. Therefore, the Company anticipates that its production, and likely many other companies' production, will be adversely affected in the Gulf of Mexico during 2012 and possibly beyond because of permitting delays. The Company is unable to predict to what extent these delays and additional processes will ultimately impact its operations in the Gulf of Mexico.

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%. 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. The Company had recorded cumulative expense of \$102.1 million through 2010 based on the anticipated settlement of the working interest reduction. The Company made a settlement payment to certain Terra Nova partners in January 2011 to equalize the value of oil sold and costs incurred since about March 2005 related to the difference between the Company's 10.475% ultimate working interest and its original 12.0% interest. The final settlement paid was less than the Company's original estimate and, therefore, a credit of \$5.4 million was recorded to income in 2011. Oil production in 2011 was about 6,100 barrels of oil per day at Hibernia and 3,100 barrels per day at Terra Nova. Hibernia production decreased slightly in 2011 due to lower gross production and a higher royalty rate, while Terra Nova experienced well downtime and the Company's working interest was reduced from 12.0% in 2010 to 10.475% in 2011. Oil production for 2012 at Hibernia and Terra Nova is anticipated to be approximately 5,700 barrels per day and 2,800 barrels per day, respectively. Production declines at both fields in 2012 due to anticipated downtime for extended maintenance. Total proved oil reserves at December 31, 2011 at Hibernia and Terra Nova were approximately 10.8 million barrels and 6.6 million barrels, respectively.

Murphy owns a 5% undivided interest in Syncrude Canada Ltd., a joint venture located about 25 miles north of Fort McMurray, Alberta. Syncrude utilizes its assets, which include three coking units, to extract bitumen from oil sand deposits and to upgrade this bitumen into a high-value synthetic crude oil. Production in 2011 was about 13,500 barrels of synthetic crude oil per day and is expected to average about 14,200 barrels per day in 2012. Total proved reserves for Syncrude at year-end 2011 were 129.5 million barrels.

Daily production in 2011 in the WCSB averaged about 7,300 barrels of mostly heavy oil and about 189 MMCF of natural gas. Through 2011, the Company has acquired approximately 156,000 net acres of mineral rights in the northeastern British Columbia 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. Oil and natural gas daily production for 2012 in Western Canada, excluding Syncrude, is expected to be about 10,200 barrels and 243 MMCF, respectively. The increase in oil production in 2012 is primarily due to an ongoing drilling program in the Seal heavy oil area. The increase in natural gas volumes in 2012 is primarily due to ramp-up of production at Tupper West associated with wells added from an ongoing drilling program. The initial production rates for Tupper West wells have been significantly better than anticipated at project sanction. However, natural gas prices in North America have weakened significantly in early 2012. Should natural gas prices in Canada continue to remain weak during 2012, the Company may elect to delay its development drilling program in the Tupper and Tupper West areas. This would lead to lower natural gas production volumes in the WCSB in 2012 and possibly beyond. Total Western Canada proved oil and natural gas reserves at December 31, 2011, excluding Syncrude, were 19.2 million barrels and 633.6 billion cubic feet, respectively.

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Through 2011, the Company has acquired approximately 146,000 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. One well was on production test in early 2012. Additional wells are planned throughout 2012 to test various formations.

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 development. The production sharing contracts cover approximately 3.74 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. About 7,100 barrels of oil per day were produced in 2011 at Block SK 309/311, with 60% at the West Patricia field and the remainder mostly associated with gas liquids produced at other Sarawak fields. Oil production in 2012 at fields in Blocks SK 309/311 is anticipated to total about 6,000 barrels of oil per day. The Company has a gas sales contract for the Sarawak area with PETRONAS, the Malaysian state-owned oil company, and has an ongoing multi-phase development plan for several natural gas discoveries on these blocks. The gas sales contract allows for gross sales volumes of up to 250 MMCF per day through 2014, with an option to extend for seven years at 250 MMCF per day or for ten years at 350 MMCF per day. Total net natural gas sales volume offshore Sarawak was about 177 MMCF per day during 2011 (gross 242 MMCF per day). Sarawak net natural gas sales volumes are anticipated to be approximately 168 MMCF per day in 2012. Total proved reserves of oil and natural gas at December 31, 2011 for Blocks SK 309/311 were 4.7 million barrels and 253.9 billion cubic feet, respectively.

The Company made a major discovery at the Kikeh field in deepwater Block K, offshore Sabah, in 2002 and added another important discovery at Kakap in 2004. Several additional discoveries have been made in Block K at other areas. 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, including Kikeh and Kakap. Total gross acreage held by the Company in Block K as of December 31, 2011 was 1.02 million acres. Production volumes at Kikeh averaged 41,500 barrels of oil per day during 2011. Kikeh oil production declined significantly in 2011 compared to the prior year due to several wells being shut down for a portion of the year due to sand and fines produced with the oil. An extensive work program was undertaken and initial results have been successful and as expected. Oil production at Kikeh is anticipated to average approximately 49,400 barrels per day for 2012 as the development program there continues. 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 thereafter 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 2011 production totaled approximately 40 MMCF per day in 2011. Daily gas production in 2012 at Kikeh is expected to average about 49 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. Kakap development activities continued during 2011 and first production is anticipated in late 2012 or early 2013. The Siakap North 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 2013. Total proved reserves booked in Block K as of year-end 2011 were 99.7 million barrels of oil and 93.9 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. In early 2008, the Company followed up Rotan with a discovery at Biris. 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 2010 another natural gas discovery was made in

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Block H at Dolfin, and in early 2012, an additional gas discovery was made at Buluh. In 2011, the Company relinquished 30% of Block H, but retained all discovered fields. Total gross acreage held by the Company at year-end 2011 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.

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. Murphy relinquished its remaining interests in Block PM 311 and all of adjacent Block PM 312 in 2007.

United Kingdom

Murphy produces oil and natural gas in the United Kingdom sector of the North Sea. Total 2011 production in the U.K. amounted to about 2,400 barrels of oil per day and 4 MMCF of natural gas per day. Total 2012 daily production levels in the U.K. are anticipated to average about 3,000 barrels of oil and 5 MMCF of natural gas. In 2011, the Schiehallion partners approved a redevelopment plan comprising a subsea equipment upgrade with additional flowlines and new risers as well as a new floating production, storage and offloading vessel. The old vessel will be removed in 2013 and production is scheduled to resume through the new vessel in early 2016. Total proved reserves in the U.K. at December 31, 2011 were 21.6 million barrels of oil and 21.0 billion cubic feet of natural gas.

Republic of the Congo

The Company has interests in Production Sharing Agreements (PSA) covering two offshore blocks in Republic of the Congo – Mer Profonde Sud (MPS) and Mer Profonde Nord (MPN). The Company's interests cover approximately 1.33 million gross acres with water depths ranging from 490 to 6,900 feet, and the Company serves as operator of 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 2011 averaged 5,000 barrels per day at Azurite for the Company's 50% interest. Anticipated production in 2012 is 3,700 barrels per day, with the decrease caused by natural decline at producing wells. Total proved oil reserves at the Azurite field as of December 31, 2011 were 2.3 million barrels. A significant revision was made in 2011 to reduce proved oil reserves at the Azurite field. The reserve revision was necessary based on the significantly lower oil recovery from producing wells. The reserve reduction led to an impairment charge of \$368.6 million during 2011. 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 allocates 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 Titane Marine in 2010 in the MPN block found accumulations of crude oil for which appraisal plans are pending. Development options are currently being studied. Other prospects in the MPN block are being evaluated and exploration wells are being planned for 2012.

Australia

The Company holds three exploration permits in Australia and serves as operator of each. A number of exploration wells will be drilled on the permits between 2012 and 2015. A 40% interest in Block AC/P36 in the Browse Basin offshore northwestern Australia covering 1.00 million gross acres was acquired in 2007 and one unsuccessful well has been drilled. The Company expects to increase its working interest in this block to 100% in 2012. Block WA-423P, also in the Browse Basin, was acquired in November 2008. The permit covers approximately 1.43 million gross acres with the Company holding a 40% working interest. Three-dimensional seismic has been acquired and a one year extension of the permit has been granted. Block NT/P80 in the Bonaparte Basin, offshore northwestern Australia, was acquired in June 2009 and covers approximately 1.21 million gross acres. Two-dimensional seismic was acquired and processed in 2011 on this block on which the Company's working interest is 40%.

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Indonesia

In May 2008, the Company entered into a production sharing contract in Indonesia, at a 100% interest, in the South Barito block in south Kalimantan on the island of Borneo. The block covers approximately 1.24 million gross acres. The agreement calls for relinquishment of 25% of acreage during 2012. 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 835 thousand gross acres. 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 2012. 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. Murphy is the operator of all the Indonesian concessions.

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. These blocks cover a significant portion of acreage formerly held by the Company in Malaysia Blocks L and M. The Malaysian Production Sharing Contracts covering Blocks L and M were terminated in early 2010. 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 drilled in 2011 and were unsuccessful.

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 plans an exploration well in 2012. In July 2011, the Company entered into an agreement with KRG to acquire a 20% non-operated interest in the Baranan block. Baranan covers approximately 178 thousand acres, and exploration plans call for seismic acquisition and the first exploration well in 2012.

Suriname

In June 2007, Murphy entered into a production sharing contract covering Block 37, offshore Suriname. Murphy operates this block and has a 100% working interest, subject to a potential reduction to 80% should the state oil company exercise its back-in option. Block 37 covers approximately 2.16 million gross acres and has water depths ranging from 160 to 1,000 feet. The contract provides for a six-year exploration period with two phases. Phase I has a four-year period that requires the acquisition of 3D seismic and the drilling of two wells. The 3D seismic was shot in late 2008 and early 2009, and interpretation of this data occurred in 2009. The first two exploration wells were drilled in late 2010 and early 2011 and were unsuccessful. Further exploration activities are presently being evaluated.

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 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

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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.

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. Sterling retained a 50% non-operated interest in the block. The NTEM block, situated in the Douala Basin offshore Cameroon, encompasses 514 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.

Ecuador

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 they 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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Total proved oil and natural gas reserves as of December 31, 2011 are presented in the following table.

	Oil (millions of barrels)	Proved Reserves Synthetic Oil	Natural Gas (billions of cubic feet)
Proved Developed Reserves:			
United States	20.8		58.2
Canada	32.6	120.5	427.1
Malaysia	57.2		210.5
United Kingdom	5.1		15.8
Republic of the Congo	2.3		
Total proved developed reserves	118.0	120.5	711.6
Proved Undeveloped Reserves:			
United States	34.5		40.2
Canada	4.0	9.0	211.8
Malaysia	47.2		137.3
United Kingdom	16.5		5.2
Republic of the Congo			
Total proved undeveloped reserves	102.2	9.0	394.5
Total proved reserves	220.2	129.5	1,106.1

Proved Undeveloped Reserves

Murphy's proved undeveloped reserves at December 31, 2011 increased 67.7 million barrels of oil equivalent (MMBOE) from a year earlier. Approximately 24.8 MMBOE of proved undeveloped reserves were converted to proved developed reserves during 2011. The majority of the proved undeveloped reserves migration to the proved developed category occurred at the Tupper and Tupper West gas 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 2011, there were 11.7 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. The Company spent \$422.1 million in 2011 to convert proved undeveloped reserves to proved developed reserves. The Company expects to spend about \$2.1 billion in 2012, \$1.4 billion in 2013 and \$520 million in 2014 to move currently undeveloped proved reserves to the developed category. The higher level of spend in 2012 is caused by significant drilling in the year at several locations, including the Kikeh field, the Eagle Ford Shale and the Tupper West 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, 2011, 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, 2011 were approximately 177 MMBOE, which is 33% 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 2011. 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

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necessary to wait for depletion of other wells prior to initiating further development of these two locations. The 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 2011. 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 1% of the Company's total proved reserves at year-end 2011. 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 General Manager of Corporate Reserves (General Manager) who is independent of the Company's oil and gas management. The General Manager reports to an Executive Vice President of Murphy Oil Corporation, who in turn reports directly to the President of the Company. The General Manager makes presentations to the Board of Directors periodically about the Company's reserves. The General 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 General 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 General Manager and qualified engineering staff from areas of the Company other than the area being audited. The General Manager may also utilize qualified independent reserves consultants to assist with the internal audits or to perform separate audits as considered appropriate. On occasion, the Company may use independent reserves consultants to determine its proved reserves reported in this Form 10-K. At December 31, 2011, the Company utilized Ryder Scott Company, L.P., an independent petroleum engineering company, to prepare estimated proved oil and natural gas reserves for the Eagle Ford Shale area in South Texas and the United Kingdom. The total estimated proved reserves prepared by Ryder Scott represented 16% of the Company's total proved oil reserves and 5% of the total proved natural gas reserves as of December 31, 2011. Ryder Scott's report, including a description of their engineer's technical qualifications for estimating reserves, is included as Exhibit 99.6 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

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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 General 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 reserve estimators to ensure SEC requirements associated with reserve 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 reserve estimation.

Qualifications of General Manager of Corporate Reserves

The Company believes that it has qualified employees generating oil and gas reserves. Mr. Brad Gouge serves as General Manager of Corporate Reserves after joining the Company in mid-2008. Prior to that time, Mr. Gouge was Vice President at a major petroleum engineering consulting firm. He previously was a production and then reservoir engineer with a major integrated oil company. Mr. Gouge earned a Bachelors of Science degree in Petroleum Engineering from Texas A&M University and has attended numerous industry training courses. Mr. Gouge is a registered Professional Engineer in the state of Texas and is an instructor for a Society of Petroleum Engineers (SPE) Petroleum Reserves course. He is also co-author of two papers on estimating petroleum reserves which have been published by the SPE and serves on the SPE Oil and Gas Reserves Committee (ORGC), as well as, the Joint Committee on Reserves Evaluator Training (JCRET).

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, 2011 are shown on page 5 of the 2011 Annual Report. In 2011, 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 33 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, 2011, 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.

Area (Thousands of acres)		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
United States	Onshore	16	12	287	234	303	246
	Gulf of Mexico	13	5	1,027	635	1,040	640
	Alaska	4	1	2		6	1
Total United States		33	18	1,316	869	1,349	887
Canada	Onshore, excluding oil sands	63	57	610	561	673	618
	Offshore	94	8	117	10	211	18
	Oil sands Syncrude	96	5	160	8	256	13
Total Canada		253	70	887	579	1,140	649
Malaysia		164	136	3,580	2,194	3,744	2,330
United Kingdom		34	4	17	2	51	6
Republic of the Congo		1		1,332	902	1,333	902
Suriname				2,959	2,959	2,959	2,959
Australia				3,640	1,456	3,640	1,456
Indonesia				4,174	3,218	4,174	3,218
Brunei				2,934	519	2,934	519
Cameroon				514	257	514	257
Iraq				331	112	331	112
Spain				36	6	36	6
Totals		485	228	21,720	13,073	22,205	13,301

Certain acreage held by the Company will expire in the next three years. Scheduled expirations in 2012 include 36 thousand net acres in Block PM 311 in Malaysia; and 188 thousand net acres in the United States. In 2013, 485 thousand net acres expire in Block H Malaysia; 629 thousand net acres expire in Block P Malaysia; 433 thousand acres in Block 37 in Suriname; and 116 thousand net acres expire in the United States. In 2014, 447 thousand net acres expire in South Barito Indonesia; 96 thousand net acres expire in Semai II Indonesia; 405 thousand net acres expire in Semai IV Indonesia; 619 thousand net acres expire in Wokam Indonesia; 448 thousand net acres expire in Blocks MPS and MPN in Republic of the Congo; and 134 thousand net acres expire 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.

The following table shows the number of oil and gas wells producing or capable of producing at December 31, 2011.

Country	Oil Wells		Gas Wells	
	Gross	Net	Gross	Net
United States	81	43	21	12
Canada	364	266	141	141
Malaysia	32	26	34	29
United Kingdom	36	3	23	2
Republic of the Congo	6	3		

Totals	519	341	219	184
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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
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
2009												
Exploratory	1.3	0.6			5.6	1.6			0.5	0.7	7.4	2.9
Development	1.1		42.0	3.0	17.0		0.4		0.5		61.0	3.0

Murphy's drilling wells in progress at December 31, 2011 are shown below.

Country	Exploratory		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	13	11.9	6	3.6	19	15.5
Canada			7	7.0	7	7.0
Malaysia			2	1.6	2	1.6
Totals	13	11.9	15	12.2	28	24.1

Refining and Marketing

The Company's refining and marketing businesses are located in the United States and United Kingdom. The U.S. business primarily consists of retail marketing of petroleum products through a large chain of motor refueling stations. Most of these stations are located on or near Walmart store sites, with the remaining 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 crude oil and refined products trading business. The Company sold both 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. The Company has announced its intention to sell its U.K. refining and marketing operations.

Murphy Oil USA, Inc. (MOUSA), a wholly owned subsidiary of Murphy Oil Corporation, markets refined products through a network of retail gasoline stations and unbranded wholesale customers in a 23-state area, primarily in the Southern and Midwestern United States. Murphy's retail 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's stations also include stand-alone locations using the Murphy Express® brand. At December 31, 2011, the Company marketed products through 1,128 Murphy owned and operated stations. Of the Company stations, 1,003 are located on parking lots of Walmart Supercenters and 125 are stand-alone Murphy Express locations. MOUSA plans to build additional retail gasoline stations at Walmart Supercenters and other stand-alone locations in 2012 and beyond.

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Below is a table that lists the states where we operate Company-owned retail sites at December 31, 2011 and the number of retail sites in each state.

State	No. of stations	State	No. of stations	State	No. of stations
Alabama	65	Kansas	1	New Mexico	6
Arkansas	60	Kentucky	37	Ohio	42
Colorado	1	Louisiana	60	Oklahoma	50
Florida	99	Michigan	23	South Carolina	44
Georgia	77	Minnesota	7	Tennessee	75
Iowa	21	Missouri	46	Texas	236
Illinois	26	Mississippi	48	Virginia	3
Indiana	32	North Carolina	69	Total	1,128

Refined products are supplied from six 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 three 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.

The Company owns land underlying 899 of the stations on Walmart parking lots. No rent is payable to Walmart for the owned locations. For the remaining gasoline 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 in the United States. The 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. Sales from the Company's U.S. retail marketing stations represented 47.4% of consolidated Company revenues in 2011, 53.1% in 2010 and 51.4% in 2009. As the Company continues to expand the number of retail operated gasoline stations, total revenue generated by this business is expected to grow. MOUSA's share of retail gasoline sales was approximately 2.6% of the total U.S. market during 2011.

In addition to the refined products sold at our retail gasoline stations, our stores carry a broad selection of snacks, beverages, tobacco products, and non-food merchandise. Our merchandise offer includes two private label products available at our retail stations, including an isotonic drink offered in several flavors and a private label energy drink. In 2011, we purchased more than 90% 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:

	2011	2010	2009
Merchandise sales (in millions)	\$ 2,115.6	1,969.2	1,706.3
Merchandise sales revenue per store month	\$ 158,144	153,530	137,623
Merchandise margin as a percentage of merchandise sales	12.8%	13.1%	12.5%

In October 2009, MOUSA acquired an ethanol production facility located in Hankinson, North Dakota, to enter the renewable fuels business as a complement to our retail operations. The \$92 million purchase price was primarily financed by \$82 million of seller-provided nonrecourse debt. The Company chose in 2010 to pay off the nonrecourse debt early. The facility is designed to produce 110 million gallons of corn-based ethanol per year. Ethanol production in 2011 totaled 116.4 million gallons at Hankinson. The Company acquired a partially constructed ethanol production facility in Hereford, Texas, in late 2010. The Company paid \$40 million for the

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facility at purchase and spent approximately \$25.1 million to complete construction of the facility. The Hereford facility is designed with production capacity of 105 million gallons of corn-based ethanol per year, and commenced operation near the end of the first quarter of 2011. Total annualized ethanol production during the last six months of 2011 amounted to about 90 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 income. During 2011, the Company sold 358,000 tons of DDGS and 535,000 tons of WDGS.

Murphy owns an interest in a crude oil pipeline with a diameter of 24 inches that connects storage at the Louisiana Offshore Oil Port (LOOP) at Clovelly, Louisiana, to the 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.

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 1,200 acre site owned by the Company; 750 acres are used by the refinery and the remainder is rented for agricultural use. The Milford Haven, Wales, 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 has consistently performed at or above nameplate capacity during 2011. Murphy has announced its intention to sell the Milford Haven refinery as well as U.K. marketing assets.

Refinery capacities at Milford Haven, Wales at December 31, 2011 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	37,000
Naphtha hydrotreating		18,300
Catalytic reforming		18,300
Distillate hydrotreating		74,000
Isomerization		11,300
Production capacity	barrels per stream day	
Alkylation		6,300
Crude oil and product storage capacity	barrels	8,908,000

At the end of 2011, Murco distributed refined products in the United Kingdom from the wholly-owned Milford Haven refinery, three wholly owned terminals supplied by rail, six terminals owned by others where products are received in exchange for deliveries from the Company's terminals and eight terminals owned by others where products are purchased for delivery. At December 31, 2011, there were 233 Company stations, 222 of which were branded MURCO with the remainder under various third party brands. The Company owns the freehold under 149 of the sites and leases the remainder. The Company also supplied 226 MURCO branded dealer stations at year-end 2011.

In 2011, Murphy owned approximately 7.5% of the refining capacity in the United Kingdom. MURCO's fuel sales represented 2.1% of the total U.K. market share in 2011.

A statistical summary of key operating and financial indicators for each of the seven years ended December 31, 2011 are reported on page 6 of the 2011 Annual Report.

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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 41 through 46.

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.

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 reserve 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 in 2010 and 2011 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

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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.

Actual future crude oil and natural gas production may vary substantially from the reported quantity of our proved reserves due to a number of factors, including:

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

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

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

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

The Company's proved undeveloped reserves represent significant portions of total proved reserves. As of December 31, 2011, approximately 32% of the Company's proved oil reserves and 36% 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.

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 \$95 per barrel in 2011, \$80 per barrel in 2010 and \$62 per barrel in 2009. Earnings for the exploration and production business were favorably impacted in 2011 by the higher oil prices. The Company's net income is also significantly affected by changes in the margins on refining and marketing operations. As demonstrated in 2011, the sales prices for oil and natural gas can be significantly different in U.S. markets compared to markets in foreign locations. 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. 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. However, certain oil and natural gas production, particularly in Sarawak Malaysia and the U.K., was sold at a premium to average U.S. natural gas prices in 2011 due to different pricing structures for gas in these regions.

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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 2011, significant wildcat wells were primarily drilled offshore Brunei, Indonesia and Suriname. The Company's 2012 exploratory drilling program includes wells onshore in Western Canada and Kurdistan and offshore in the Gulf of Mexico, Brunei, Republic of the Congo, Australia and Malaysia.

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 September 2012. Outstanding notes of \$350 million mature in April 2012. 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 lead to reduced prices for oil, natural gas and refined products. 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 2011, approximately 19% of the Company's total production was at fields operated by others, while at December 31, 2011, approximately 38% 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, 2011, approximately 31% of proved reserves, as defined by the

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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 tax changes, royalty increases 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. 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 and intentional terrorist attacks 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. In May 2010, the U.S. President placed a temporary moratorium on new drilling in the Gulf of Mexico that forced the Company to defer planned exploration drilling in the Gulf of Mexico, and to renegotiate a drilling contract to move a deepwater drilling rig to Republic of the Congo. Further impacts of the accident and oil spill include added delays in deepwater Gulf of Mexico drilling activities, and additional future regulations covering offshore drilling operations, plus expected higher costs for future drilling operations and offshore insurance. The 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'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

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and property damage, including claims arising from sudden and accidental pollution events. The Company also maintains insurance coverage with an additional limit of \$250 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. During 2005, damages from hurricanes caused a temporary shut-down of certain U.S. oil and gas production operations as well as the Meraux, Louisiana, refinery. The Company repaired the Meraux refinery and it restarted operations in mid-2006, but the Company did not fully recover repair costs incurred at Meraux under its insurance policies. See Note P in the consolidated financial statements for further discussion.

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.

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 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. 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 L 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.

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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, 2011.

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 E Property, Plant and Equipment beginning on page F-17.

Executive Officers of the Registrant

The age at January 1, 2012, 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.

David M. Wood Age 54; President and Chief Executive Officer and Director and Member of the Executive Committee since January 2009. Mr. Wood served as Executive Vice President responsible for the Company's worldwide exploration and production operations from January 2007 through December 2008 and President of Murphy Exploration & Production Company-International from March 2003 through December 2006.

Kevin G. Fitzgerald Age 56; 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.

Roger W. Jenkins Age 50; Executive Vice President Exploration and Production since August 2009. Mr. Jenkins 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.

Thomas McKinlay Age 48; Executive Vice President, World Wide Downstream Operations since January 2011. Mr. McKinlay was Vice President, U.S. Manufacturing from August 2009 to January 2011. Mr. McKinlay also became President of the Company's U.S. refining and marketing subsidiary effective January 2011 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 60; 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 49; 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 53; 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 42; Vice President and Treasurer since January 2007. Ms. West was Director of Investor Relations from July 2001 through December 2006.

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Kelli M. Hammock Age 40; Vice President, Administration since December 2009. Ms. Hammock was General Manager, Administration from June 2006 to November 2009.

Thomas J. Mireles Age 39; 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 44; 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.

Table of Contents**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 2,212 stockholders of record as of December 31, 2011. Information as to high and low market prices per share and dividends per share by quarter for 2011 and 2010 are reported on page F-55 of this Form 10-K report.

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, 2006 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.

	2006	2007	2008	2009	2010	2011
Murphy Oil Corporation	100	169	89	111	156	119
S&P 500 Index	100	105	66	84	97	99
NYSE ARCA Oil Index	100	134	87	98	115	119

Table of Contents**Item 6. SELECTED FINANCIAL DATA**

<i>(Thousands of dollars except per share data)</i>	2011	2010	2009	2008	2007
Results of Operations for the Year					
Sales and other operating revenues	\$ 27,689,332	20,225,764	16,800,972	24,134,820	15,573,086
Net cash provided by continuing operations	1,999,875	3,028,070	1,770,205	2,863,748	1,438,079
Income from continuing operations	740,932	779,559	713,854	1,764,631	560,570
Net income	872,702	798,081	837,621	1,739,986	766,529
Per Common share diluted					
Income from continuing operations	\$ 3.81	4.03	3.71	9.18	2.93
Net income	4.49	4.13	4.35	9.06	4.01
Cash dividends per Common share	1.10	1.05	1.00	.875	.675
Percentage return on ¹					
Average stockholders' equity	9.9	10.3	12.5	29.1	16.8
Average borrowed and invested capital	9.2	9.4	10.9	24.4	13.9
Average total assets	5.7	5.9	7.0	15.1	8.5
Capital Expenditures for the Year²					
Continuing operations					
Exploration and production	\$ 2,768,222	2,034,828	1,807,561	1,928,346	1,740,327
Refining and marketing	122,301	290,090	263,413	348,476	481,959
Corporate and other	5,218	5,899	22,967	3,235	4,146
	2,895,741	2,330,817	2,093,941	2,280,057	2,226,432
Discontinued operations	48,071	117,323	113,328	84,629	130,915
	\$ 2,943,812	2,448,140	2,207,269	2,364,686	2,357,347
Financial Condition at December 31					
Current ratio	1.22	1.21	1.55	1.51	1.37
Working capital	\$ 622,743	619,783	1,194,087	958,818	777,530
Net property, plant and equipment	10,475,149	10,367,847	9,065,088	7,727,718	7,109,822
Total assets	14,138,138	14,233,243	12,756,359	11,149,098	10,535,849
Long-term debt	249,553	939,350	1,353,183	1,026,222	1,516,156
Stockholders' equity	8,778,397	8,199,550	7,346,026	6,278,945	5,066,174
Per share	45.31	42.52	38.44	32.92	26.70
Long-term debt percent of capital employed	2.8	10.3	15.6	14.0	23.0

¹ Company management uses certain measures for assessing our 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, we measure our 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 our 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.

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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.

- ² 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, the United Kingdom 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 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.

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. The sales price for a barrel of West Texas Intermediate (WTI) crude oil averaged \$95.11 in 2011, \$79.61 in 2010 and \$62.05 in 2009. The NYMEX natural gas price per million British Thermal Units (MMBTU) averaged \$4.03 in 2011, \$4.38 in 2010 and \$3.94 in 2009. 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. The rise in prices of WTI based crude oil, which is only used as a benchmark in North America, was held back in 2011 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 the year. The average price of NYMEX natural gas was 8% lower in 2011 than 2010. The disparity between crude oil and natural gas prices in North America continued to widen during 2011 compared to an energy equivalent basis of six thousand cubic feet of gas to one barrel of oil due to gas production growth that exceeded demand. The increase in natural gas production was primarily associated with volumes produced at a number of expanding U.S. unconventional shale gas plays. Natural gas prices in North America have declined further in early 2012 due to milder than normal winter temperatures across much of the U.S. Crude oil and North American natural gas prices were both higher in 2010 than in 2009. Crude oil prices generally strengthened in 2010 as the worldwide economy began to show signs of recovery following the deep recession that began in 2008. WTI oil prices in 2010 averaged 28% higher than 2009, while NYMEX natural gas prices increased 11%. 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 57% of the total hydrocarbons produced on an energy equivalent basis (one barrel of oil equals six thousand cubic feet of natural gas) by the Company in 2011. In 2012, the percentage of hydrocarbon production represented by oil is expected to remain relatively consistent with 2011. If the prices for crude oil and natural gas should weaken in 2012 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.

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Results of Operations

Net income in 2011 of \$872.7 million (\$4.49 per diluted share) was 9% better than net income in 2010 of \$798.1 million (\$4.13 per diluted share). The improvement in 2011 net income in comparison to 2010 was primarily attributable to higher oil prices in 2011 and stronger U.S. retail marketing and refining margins. These were mostly offset by an impairment charge of \$368.6 million in 2011 to reduce the carrying value of the Azurite oil field offshore Republic of the Congo to fair value. 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 \$131.8 million (\$0.68 per diluted share) compared to income from discontinued operations of \$18.5 million (\$0.10 per diluted share) in 2010. The results of discontinued operations in both years are associated with two U.S. refineries and certain associated marketing assets that were sold in 2011. Income from continuing operations was \$740.9 million (\$3.81 per diluted share) in 2011 compared to \$779.6 million (\$4.03 per diluted share) in 2010.

Murphy had net income in 2010 of \$798.1 million (\$4.13 per diluted share), down 5% compared to net income of \$837.6 million (\$4.35 per diluted share) in 2009. Net income in 2010 included income from discontinued operations of \$18.5 million (\$0.10 per diluted share), while 2009 had income from discontinued operations of \$123.8 million (\$0.64 per diluted share). The results of discontinued operations in 2010 were associated with operating income of the two U.S. refineries and associated marketing assets that were sold in 2011; income from discontinued operations in 2009 primarily arose from a \$103.6 million after-tax gain on disposal of all Ecuador assets in March 2009, but also included operating income of the U.S. refineries and marketing assets sold in 2011. Income from continuing operations was \$779.6 million (\$4.03 per diluted share) in 2010 and \$713.8 million (\$3.71 per diluted share) in 2009. Income in 2010 rose for both exploration and production (E&P) and refining and marketing (R&M) operations compared to the prior year. Earnings for the Company's E&P operations increased in 2010 primarily due to higher sales prices and sales volumes of crude oil and natural gas. The Company's R&M earnings from continuing operations were higher in 2010 primarily due to stronger profits on U.S. retail gasoline fuel and merchandise sales. Earnings in 2010 were unfavorably affected compared to 2009 by higher net costs associated with Corporate activities that were not allocated to operating segments, with the higher costs primarily caused by an unfavorable variance for the effects of transactions denominated in foreign currencies.

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

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. These earnings included income from discontinued operations of \$131.8 million (\$0.68 per diluted share) in 2011 compared to income of \$18.5 million (\$0.10 per diluted share) in 2009. Discontinued operations in both years were associated with the Company's two U.S. refineries which were sold in 2011. Income from continuing operations amounted to \$740.9 million (\$3.81 per diluted share) in 2011, down from \$779.6 million (\$4.03 per diluted share) in 2010. The lower earnings from continuing operations in 2011 was primarily attributable to a \$368.6 million impairment charge to reduce the carrying value of the Azurite oil field, offshore Republic of the Congo, to fair value. Higher sales prices for worldwide crude oil and Sarawak natural gas production and higher U.S. retail marketing profits partially offset the impact of the Congo impairment.

E&P income in 2011 was \$181.2 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 \$82.8 million less in 2011 than 2010 primarily due to gains from transactions

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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 the current year. Interest and other income (loss) in 2011 was favorable \$90.5 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 \$314.8 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 \$197.6 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 \$41.8 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 \$21.1 million in 2011 mostly due to fewer barrels of oil equivalent produced in 2011 compared to 2010. Impairment of long-lived assets 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 \$5.8 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 related to 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 the most recent year. 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 \$200.9 million more in 2011 than 2010 due to higher pretax income in 2011 plus higher exploration and impairment expenses in the year for which no tax benefit was recognizable by the Company. The effective tax rate on a consolidated basis increased from 43.9% in 2010 to 52.2% 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 benefit can presently be 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 \$113.2 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.

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2010 vs. 2009 Net income in 2010 was \$798.1 million (\$4.13 per diluted share) compared to \$837.6 million (\$4.35 per diluted share) in 2009. The 2010 and 2009 results included income from discontinued operations of \$18.5 million (\$0.10 per diluted share) and \$123.8 million (\$0.64 per diluted share), respectively. The discontinued operations income in 2010 included the operating results of the Meraux, Louisiana, and Superior, Wisconsin, refineries and associated marketing assets that were sold in 2011. The 2009 discontinued operations income included the operating results of these two refineries plus properties in Ecuador that were sold in March 2009 at an after-tax gain of \$103.6 million. Income from continuing operations in 2010 and 2009 were \$779.6 million (\$4.03 per diluted share) and \$713.8 million (\$3.71 per diluted share), respectively. The higher 2010 income from continuing operations compared to 2009 was caused by higher earnings in both the E&P and R&M businesses, but these were partially offset by higher net costs for unallocated corporate activities.

E&P income from continuing operations improved \$115.1 million in 2010, primarily due to a \$10.70 per barrel higher realized sales price for crude oil in 2010. The 2009 results were impacted by two unusual items. First, an after-tax gain of \$158.3 million in 2009 was derived from a recovery of certain deepwater Gulf of Mexico federal royalties paid in prior years. Second, an after-tax charge of \$58.4 million was recorded in 2009 associated with a required one-time working interest redetermination at the Terra Nova field, offshore Eastern Canada. The 2010 E&P results were also favorably affected, but in less significant measures, by higher sales volumes for crude oil and natural gas and higher sales prices for natural gas. E&P was unfavorably affected in 2010 compared to the prior year by higher expenses for exploration, production, depreciation and administration. Income from R&M continuing operations was \$85.6 million more in 2010, with the improvement mostly attributable to slightly more than a \$0.03 per gallon improvement in margins on sale of gasoline at U.S. retail marketing stations. This was partially offset by higher net losses in 2010 for U.K. R&M operations. The net costs of corporate activities were higher by \$134.9 million in 2010, mostly attributable to unfavorable effects of transactions denominated in foreign currencies. To a lesser degree, the 2010 corporate net costs were unfavorably affected by lower interest income and higher expenses for interest and administration. The unfavorable variance in foreign currency transactions in 2010 was primarily attributable to a strengthening of the Malaysian ringgit versus the U.S. dollar and weakening of the British pound sterling against the U.S. dollar during the year.

Sales and other operating revenues grew \$3.4 billion in 2010 compared to 2009 mostly due to higher sales prices for gasoline and other motor fuels in the later year. Additionally, higher sales prices and sales volumes for crude oil and natural gas in the E&P segment contributed to the increase in 2010 revenue. Gain on sale of assets was \$2.8 million less in 2010 than 2009 because the earlier year included a \$3.9 million gain on sale of a small Canadian natural gas field. Interest and other operating income (loss) was unfavorable by \$147.4 million in 2010 compared to 2009 mostly due to a \$114.3 million unfavorable variance from the effects of transactions denominated in foreign currencies, plus nonrecurring interest income in 2009 of \$42.0 million associated with a recovery of Federal royalties paid in prior years for production at certain deepwater Gulf of Mexico fields. The expense associated with crude oil and product purchases increased by \$2.5 billion in 2010 compared to 2009 due to higher average 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. and higher costs for crude oil feedstocks at the Company's U.K. refinery. Operating expenses were \$327.9 million higher in 2010 than 2009 due to a combination of higher oil and natural gas production costs and higher costs for U.S. retail gasoline station operations. Exploration expenses rose \$27.1 million in 2010 compared to 2009 due to higher geophysical costs in the Gulf of Mexico and Republic of the Congo, higher amortization expense for undeveloped leases in the Eagle Ford Shale, and higher administrative office and study costs in foreign locations. Exploration costs in 2010 included lower dry hole costs in Malaysia, Australia and the U.S., which more than offset higher dry hole costs in Republic of the Congo, Suriname and the U.K. Selling and general expenses were \$46.8 million more in 2010 than in 2009 primarily due to higher employee compensation costs. Depreciation, depletion and amortization expense rose \$243.5 million in 2010 versus 2009 due to higher natural gas and crude oil sales volumes in 2010, higher E&P per-unit depreciation rates, and higher R&M depreciation that included a new ethanol production facility, more U.S. retail gasoline stations in operation and a crude unit expansion at the Milford Haven, Wales, refinery that was completed in 2010. Impairment of properties was nil in 2010 and \$5.2 million in 2009, with the earlier year costs related to write-off of an underperforming natural gas field in the Gulf of Mexico. Accretion of asset retirement

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obligations was \$5.7 million more in 2010 than 2009 primarily due to higher discounted abandonment liabilities in 2010 for wells drilled in Malaysia and for synthetic oil operations at Syncrude. Expense for redetermination of working interest at the Terra Nova field was \$64.9 million less in 2010 than 2009 because the earlier year included cumulative costs for the period of December 2004 through 2009, while 2010 costs related only to that year's operations at Terra Nova. Interest expense was \$0.2 million higher in 2010 primarily due to nine months of interest in 2010 on nonrecourse debt associated with the Hankinson, North Dakota, ethanol production facility, compared to three months of interest on this debt in 2009 following the October 1, 2009 acquisition date. The nonrecourse debt was paid off by the Company in September 2010. The higher nonrecourse debt interest was mostly offset by lower interest expense on outstanding general bank financing balances in 2010. Capitalized interest was \$10.2 million less in 2010 than in the prior year due to interest amounts allocated to the Sarawak natural gas development in 2009 prior to start-up of operations later that year, partially offset by higher interest allocated to the Tupper West gas development in 2010. Income tax expense in 2010 was \$87.6 million more than 2009 due to higher pretax earnings and a slightly higher overall effective tax rate in the later year. The consolidated effective tax rate was 43.9% in 2010 compared to 42.2% in 2009, with the rate increase in the later year caused by a larger percentage of earnings in higher tax jurisdictions in 2010 and due to higher 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 2010 or future years to reduce taxes owed. The tax rates in both 2010 and 2009 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 2010 or future years. Income from discontinued operations was \$18.5 million (\$0.10 per diluted share) in 2010 and \$123.8 million (\$0.64 per diluted share) in 2009. Income from discontinued operations in both years included operating results for the two U.S. petroleum refineries sold in late 2011. Income from discontinued operations in 2009 included an after-tax gain of \$103.6 million on Ecuador assets which were sold in March 2009.

Segment Results In the following table, the Company's results of operations for the three years ended December 31, 2011, 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.

<i>(Millions of dollars)</i>	2011	2010	2009
Exploration and production – continuing operations			
United States	\$ 152.7	72.7	178.0
Canada	328.0	213.8	64.8
Malaysia	812.7	659.4	561.9
United Kingdom	11.5	30.5	12.6
Republic of the Congo	(385.3)	(77.2)	(20.6)
Other	(293.9)	(92.3)	(104.9)
	625.7	806.9	691.8
Refining and marketing – continuing operations			
United States	223.6	165.3	65.5
United Kingdom	(33.3)	(34.7)	(20.5)
	190.3	130.6	45.0
Corporate and other	(75.1)	(157.9)	(23.0)
Income from continuing operations	740.9	779.6	713.8
Income from discontinued operations	131.8	18.5	123.8
Net income	\$ 872.7	798.1	837.6

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Exploration and Production Earnings from exploration and production (E&P) continuing operations were \$625.7 million in 2011, \$806.9 million in 2010 and \$691.8 million in 2009.

E&P income in 2011 was \$181.2 million less than in 2010 primarily due to a \$368.6 million impairment charge in 2011 to reduce the carrying value of the Azurite oil field to fair value. The 2011 period also had higher exploration expense, lower crude oil sales volumes and lower North American natural gas sales prices. But the latest year benefited from higher oil and Sarawak natural gas sales prices and higher natural gas sales volumes. The Company's realized crude oil sales prices 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 were 22% lower in 2011 compared to 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 the latest year-end, while in 2010, Kikeh sales volumes exceeded production, which effectively reduced the Company's unsold inventory balance from year-end 2009. 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 volume in the U.K. in 2011 were below 2010 levels primarily due to lower oil volumes produced at the Schiehallion and Mungo/Monan fields during the later year. 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 increased 28% 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.

Income from E&P continuing operations in 2010 was \$115.1 million more than in 2009. The increase was primarily attributable to higher sales prices for crude oil and other liquid hydrocarbons produced in 2010. The Company's average realized sales price for crude oil, condensate and gas liquids in 2010 increased \$10.70 per barrel over 2009. The Company's average natural gas sales prices in North America and Sarawak Malaysia were also higher in 2010 than 2009. E&P income in 2009 included a \$158.3 million after-tax one-time benefit from recovery of previously paid federal royalties associated with certain fields in the deep waters of the Gulf of Mexico. Although both 2010 and 2009 had charges associated with a redetermination of working interest at the Terra Nova field offshore Eastern Canada, 2009 charges were higher by \$64.9 million due to 2009 including estimated costs to settle the period from December 2004 to 2009, while 2010 included only costs for that year's operating activities. Earnings in 2010 benefited from higher crude oil and natural sales volumes compared to 2009. Crude oil and liquids sales volumes increased 2% in 2010 while natural gas sales volumes rose 91%. The increase in hydrocarbon sales volumes in 2010 led to higher expenses for production and depreciation of \$225.0 million and \$229.2 million, respectively. The 2010 year also had higher exploration expenses of \$27.1 million compared to 2009, essentially due to higher expenses related to geophysical activities, undeveloped lease amortization and administration, which were somewhat offset by lower expenses for dry holes. Crude oil sales volumes increased in 2010 in the U.S. due to a full year of production at the Thunder Hawk field in the Gulf of Mexico; this field started producing in July 2009. Heavy oil sales volumes in Canada in 2010 were less than 2009 due to lower gross production and a higher royalty rate in the Seal area of Western Canada. Oil sales volumes in 2010 offshore Canada were below 2009 levels mostly due to lower gross production at the Terra Nova field and a higher royalty rate at the Hibernia field. Synthetic oil sales at Syncrude increased in 2010 due to higher gross production compared to 2009. Sales volumes for crude oil produced in Malaysia were lower

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in 2010 due to less production at the Kikeh field offshore Sabah. Crude oil sold in the U.K. rose in 2010 due to making up for undersold inventory barrels produced in 2009 at the Schiehallion field. Crude oil sales increased in 2010 in Republic of the Congo due to a full year of production at the Azurite field following production start-up in August 2009. Natural gas sales volumes in 2010 increased significantly compared to the prior year due to a full year of production and higher daily sales volumes at gas fields which started up in 2009 offshore Sarawak Malaysia, as well as higher sales volumes at the Tupper area in Western Canada.

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 2011 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.

<i>(Millions of dollars)</i>	2011	2010	2009
United States			
Oil and gas liquids	\$ 648.8	557.6	374.8
Natural gas	71.1	87.0	80.6
Canada			
Conventional oil and gas liquids	505.6	388.6	365.6
Synthetic oil	506.6	378.6	288.5
Natural gas	280.2	132.1	68.6
Malaysia			
Oil and gas liquids	1,583.0	1,531.1	1,478.4
Natural gas	461.3	307.1	45.4
United Kingdom			
Oil and gas liquids	92.4	118.8	54.7
Natural gas	14.3	14.1	6.4
Republic of the Congo oil	148.8	156.7	24.5
Total oil and gas revenues	\$ 4,312.1	3,671.7	2,787.5

The Company's total crude oil, condensate and natural gas liquids production from continuing operations, which excludes discontinued operations in Ecuador sold in March 2009, averaged 103,160 barrels per day in 2011, 126,927 barrels per day in 2010 and 130,522 barrels per day in 2009.

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 caused by 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 the Western Canada Sedimentary Basin 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. Sands and other fines produced with the oil 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. Oil production 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

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the later year. 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.

United States crude oil production averaged 20,114 barrels per day in 2010, up from 17,053 barrels per day in 2009. The U.S. increase was primarily attributable to a full year of oil production at the Thunder Hawk field that started up in July 2009 in the Gulf of Mexico. Heavy oil production in Western Canada declined from 6,813 barrels per day in 2009 to 5,988 barrels per day in 2010 due to a combination of lower gross production in the Seal area plus a higher royalty rate there due to higher sales prices in 2010. Crude oil production offshore Canada fell from 12,357 barrels per day in 2009 to 11,497 barrels per day in 2010 essentially due to lower production levels at Terra Nova caused by field decline and a higher royalty rate at Hibernia. Synthetic oil production of 13,273 barrels per day in 2010 exceeded 2009 volumes of 12,855 per day due to less downtime for maintenance in the later year. Crude oil and liquids production in Malaysia averaged 66,897 barrels per day in 2010, down from 76,322 barrels per day in 2009, with the decrease mainly due to downtime in the later year at Kikeh for well maintenance and installation of drilling equipment on the production facility. Crude oil production in the U.K. in 2010 was about flat with 2009 as higher production volumes at Schiehallion almost offset lower volumes due to well decline at Mungo/Monan. Oil production in Republic of the Congo rose to 5,820 barrels per day in 2010 after averaging 1,743 barrels per day for all of 2009; the Azurite field came on production in August 2009. The Company sold its interest in Block 16 and other areas in Ecuador in March 2009 and has accounted for Ecuador as discontinued operations. Oil production in Ecuador, excluded from the totals for continuing operations, averaged 1,317 barrels per day in 2009.

Worldwide sales of natural gas were 457.4 million cubic feet (MMCF) per day in 2011, 356.8 MMCF per day in 2010 and 187.3 MMCF per day in 2009.

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 the year due to delay in development drilling operations following the Macondo incident in April 2010. Natural gas production in Canada rose from 85.6 MMCF per day in 2010 to an annual Company record of 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 rose 22.4 MMCF per day at Sarawak 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 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 the just completed year.

Natural gas sales volumes in the U.S. were 53.0 MMCF per day in 2010, down from 2009 production of 54.2 MMCF per day as higher production at Thunder Hawk in the Gulf of Mexico and the Eagle Ford Shale area did not fully offset declines at fields onshore South Louisiana and at other fields in the Gulf of Mexico. Natural gas volumes in Western Canada increased from 54.9 MMCF per day in 2009 to 85.6 MMCF per day in 2010 essentially due to continued ramp-up of Tupper area production during the later year. Natural gas sales volumes in Malaysia increased in 2010 for both the Sarawak and Sabah offshore areas. Sarawak production rose to 154.5 MMCF per day in 2010 following volumes of 28.1 MMCF per day in 2009. Sarawak gas production began in September 2009 and as such was on production for all of 2010 versus four months in 2009. The Company also continued ramp-up of new wells at Sarawak gas fields during 2010. Gas sales at the Kikeh field averaged 58.2 MMCF per day in 2010, up from 46.6 MMCF per day the prior year. Natural gas sales volumes in the U.K. increased from 3.5 MMCF per day in 2009 to 5.5 MMCF per day in 2010 as gas volumes rose at both the Mungo/Monan and Amethyst fields during the later year.

The Company's average worldwide realized sales price for crude oil, condensate and gas liquids from continuing operations was \$94.54 per barrel in 2011 compared to \$67.11 per barrel in 2010 and \$56.41 per barrel in 2009.

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The Company's average realized oil sales price of \$94.54 in 2011 was an increase of 41% compared to 2010. The average price of West Texas Intermediate (WTI) crude oil rose 19% during 2011. The Company's average oil price increased more than WTI because other worldwide benchmark prices rose more than WTI during 2011. Dated Brent prices, for example, rose 40% during 2011. Additionally, the Company's realized sales price in Malaysia in 2011 and a portion of 2010 benefited from a switch to the Brent benchmark price during the prior year. Crude oil prices strengthened in 2011 due to an improvement in energy demand in association with a slowly recovering worldwide economy and unrest in Northern Africa and the Middle East during 2011 that caused concern in the oil markets about the potential for supply disruptions. Compared to 2010, the Company's average 2011 crude oil sales prices in the U.S. rose 36% to \$103.92 per barrel; heavy oil prices in Canada sold for 14% more and averaged \$57.00 per barrel; offshore Canada prices increased 43% to \$110.02 per barrel; synthetic crude oil sold for 32% more at \$102.94 per barrel; crude oil in Malaysia was up 48% and averaged \$90.14 per barrel; U.K. crude oil production sold for 41% more at \$110.13 per barrel; and crude oil in Republic of the Congo sold at \$103.02 per barrel in 2011, an increase of 38% from 2010.

The average realized crude oil sales price increased 19% in 2010 compared to 2009. The higher price for 2010 was slightly below the 28% increase in WTI sales price between the years. Other benchmark oil prices used for sale of Company crude oil did not increase at the same rate as WTI. The increase in the sales price for APPI Tapis based crude oil during 2010 did not keep pace with the increase in the WTI price due to differences in market conditions in Asia versus the U.S. During most of 2010, the Company sold its Kikeh crude oil based on the APPI Tapis benchmark price. In late 2010, the Company began to sell its Kikeh crude oil based on a Brent crude oil benchmark. Compared to 2009, the Company's average 2010 crude oil sales prices rose 27% in the U.S. to average \$76.31 per barrel; heavy oil sales prices in Canada rose 23% to an average of \$49.89 per barrel; offshore Canada oil sold at \$76.87 per barrel, an increase of 32%; Canadian synthetic crude oil sold for 27% more and averaged \$77.90 per barrel; crude oil produced in Malaysia increased 10% to an average price of \$60.97 per barrel; U.K. crude oil prices increased 27% to \$77.95 per barrel; and crude oil sold in Republic of the Congo increased only 8% to \$74.87 per barrel as the only sale in 2009 was near the end of the year when prices were above the 2009 average.

The Company's natural gas sales prices in North America in 2011 did not generally increase in concert with crude oil prices. A growing gas supply from unconventional sources such as shale operations kept gas prices in check during the latest year. The Company's average realized North American natural gas sales price was \$4.08 per thousand cubic feet (MCF) in 2011, a decline of 6% from the \$4.34 per MCF realized in 2010. Natural gas produced in 2011 offshore Sarawak was sold at an average price of \$7.10 per MCF, an increase of 34% from the \$5.31 per MCF realized during 2010. In the U.K. the average sales price rose from \$7.01 per MCF in 2010 to \$9.99 per MCF in 2011, up 43% in the current year.

Virtually all natural gas prices showed improvements in 2010 compared to 2009. The prices for natural gas generally rose in 2010 in sympathy with the increase in average crude oil prices during the same period. The Company's average sales prices for natural gas in North America increased 22% to \$4.34 per MCF in 2010. Natural gas produced offshore Sarawak sold for 31% more in 2010 than in 2009 and averaged \$5.31 per MCF in the later year. Natural gas produced in the U.K. sold at an average of \$7.01 per MCF in 2010, a 39% increase from 2009.

Based on 2011 sales volumes and deducting taxes at marginal rates, each \$1.00 per barrel and \$0.10 per MCF fluctuation in prices would have affected 2011 earnings from exploration and production continuing operations by \$23.5 million and \$10.9 million, respectively. The effect of these price fluctuations on consolidated net income cannot be measured precisely because operating results of the Company's refining and marketing segments could be affected differently.

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Production expenses from continuing operations were \$1,038.6 million in 2011, \$879.5 million in 2010 and \$654.5 million in 2009. These amounts are shown by major operating area on pages F-51 and F-52 of this Form 10-K report. Costs per equivalent barrel during the last three years are shown in the following table.

<i>(Dollars per equivalent barrel)</i>	2011	2010	2009
United States	\$ 18.05	12.46	10.62
Canada			
Excluding synthetic oil	8.65	8.45	9.44
Synthetic oil	47.91	42.61	36.64
Malaysia	13.66	9.31	8.00
United Kingdom	26.24	14.46	17.97
Republic of the Congo	26.04	31.30	43.51
Worldwide excluding synthetic oil	13.39	10.51	9.21

Production expense per equivalent barrel in the U.S. increased in 2011 compared to 2010 due to lower volumes produced at the Thunder Hawk field and higher facility rental costs in the early days of the Eagle Ford Shale operation as production ramped up. The per-unit cost for Canadian conventional oil and gas operations, excluding synthetic oil, was slightly higher in 2011 compared to 2010 as the benefit of significantly higher natural gas production at Tupper West and Tupper was more than offset by lower production volumes without a comparable reduction in costs at Hibernia and Terra Nova. Higher cost per barrel in 2011 compared to 2010 at Canadian synthetic oil operations was mostly caused by higher overall maintenance and fuel costs. Production cost per unit in Malaysia was higher in 2011 compared to 2010 primarily at Kikeh caused by higher costs for the work program to address equipment damaged by sand produced with the oil and the associated downtime which led to lower oil production. Higher per-barrel production expense in the U.K. in 2011 compared to 2010 was primarily attributable to lower production levels at all fields and extended maintenance work. Production expense in Republic of the Congo was lower on a per-unit basis in 2011 compared to 2010 due to lower gross costs incurred at the Azurite field in the later year.

Production expense per equivalent barrel in the U.S. increased in 2010 compared to 2009 due to a larger proportion of production in the later year coming from the higher-cost Thunder Hawk field in the Gulf of Mexico. Cost per barrel for Canada conventional oil and gas operations, excluding synthetic oil, was lower in 2010 than 2009 due to a larger portion of total hydrocarbons produced coming from the Tupper gas area, but this was partially offset by higher unit costs for offshore operations at Hibernia and Terra Nova. The increase in production costs per barrel for synthetic oil operations in 2010 compared to 2009 was caused by higher maintenance and natural gas costs in the current year. Production expense in Malaysia rose in 2010 compared to 2009 as higher well maintenance and workover costs at Kikeh were only partially offset by a higher proportion of lower-cost natural gas produced at fields offshore Sarawak. Production expense in 2010 in the U.K. on a per-unit basis was lower than 2009 due to less repair costs at Schiehallion and higher natural gas production at Amethyst. Per-unit production expense in 2010 in Republic of the Congo was less than in 2009 due to higher production levels associated with ramp-up of the Azurite field, which came onstream in August 2009.

Exploration expenses from continuing operations for each of the last three years are shown in total in the following table, and amounts are reported by major operating area on pages F-51 and F-52 on this Form 10-K report. Expenses other than leasehold amortization are included in the capital expenditures total for exploration and production activities.

<i>(Millions of dollars)</i>	2011	2010	2009
Dry holes	\$ 251.0	90.1	125.3
Geological and geophysical	79.7	65.1	40.5
Other	41.0	29.1	16.2
	371.7	184.3	182.0
Undeveloped lease amortization	118.2	108.0	83.2
Total exploration expenses	\$ 489.9	292.3	265.2

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Dry hole expense was \$160.9 million higher in 2011 than 2010 due to more unsuccessful exploratory drilling results in the current year, with the most significant areas including Brunei, Indonesia, Southern Alberta and Suriname. Lower dry hole costs in 2011 in Malaysia, Republic of the Congo and the U.K. somewhat offset the higher costs noted above. Geological and geophysical (G&G) expenses were \$14.6 million higher in 2011 compared to 2010. The increase in G&G expenses in 2011 was attributable to higher spending on seismic in Brunei, the Kurdistan region of Iraq, Block H Malaysia and Cameroon, but the current year included lower seismic spending in Republic of the Congo. Other exploration costs were \$11.9 million more in 2011 than 2010 mostly due to higher office costs allocable to exploration activities in Brunei, Indonesia and Iraq, and an exploration well drilling penalty in Southern Alberta. Undeveloped leasehold amortization expense was \$10.2 million higher in 2011 than 2010 mostly due to lease costs associated with concessions in the Kurdistan region of Iraq, but partially offset by slightly lower amortization costs in 2011 for Eagle Ford Shale leases in South Texas and the Montney area of Western Canada.

Dry hole expense was \$35.2 million lower in 2010 than in 2009 despite a 50% increase in spending for exploratory drilling. Dry hole expense in the U.S. was lower in 2010 mostly due to deferral of planned Gulf of Mexico drilling due to the moratorium imposed by the Federal government following the April 2010 blowout and oil spill at the Macondo well owned by other companies. Malaysian operations had lower dry hole expense in 2010 due to more successful exploratory drilling results and favorable adjustments to final costs on prior-year wells. Dry holes in the U.K. in 2010 primarily related to a decision to expense a well drilled in 2008 for which studies in 2010 indicated a lack of economical development options based on current pricing levels. Dry hole expense in Republic of the Congo was higher in 2010 than 2009 due to drilling more unsuccessful wells in the MPS block in the later year. Dry hole expense in 2010 in other foreign areas was less than in 2009 primarily due to an unsuccessful well offshore Australia in 2009. G&G expenses were \$24.6 million higher in 2010 than 2009. Areas of higher spending on seismic in the 2010 year included the Eagle Ford Shale area of South Texas, the MPN and MPS blocks offshore Republic of the Congo, and offshore Malaysia. These higher G&G costs in 2010 were somewhat offset by lower spending in the Tupper area of Western Canada and offshore Suriname. Other exploration costs in 2010 were \$12.9 million above 2009 levels primarily due to higher administrative costs for operations in Suriname, Indonesia and Australia in 2010. Undeveloped leasehold amortization expense rose \$24.8 million in 2010 compared to 2009, primarily due to higher amortization associated with lease acquisition costs in the Eagle Ford Shale area of South Texas, partially offset by less amortization expense in 2010 following sanction of development at the Tupper West property in August 2009.

The Company recorded a \$368.6 million impairment charge in 2011 to reduce the carrying value of the Azurite oil field, offshore Republic of the Congo, to fair value. The impairment charge at Azurite was necessitated by a reduction in the field's proved oil reserves at year-end 2011 due to poor well performance. An impairment charge of \$5.2 million was recorded in 2009 to write-off the remaining costs of a poorly performing natural gas field in the Gulf of Mexico.

Depreciation, depletion and amortization expense for exploration and production operations totaled \$969.7 million in 2011, \$1,005.0 million in 2010 and \$775.8 million in 2009. The \$35.3 million decrease in 2011 compared to 2010 was primarily attributable to lower overall levels of hydrocarbon volumes sold, somewhat offset by a slightly higher per-barrel depreciation rate based on a change in the mix of production between 2011 and 2010. The \$229.2 million increase in 2010 compared to 2009 was primarily caused by higher overall volumes of oil and natural gas sold during 2010. Additionally, a higher proportion of 2010 production was derived from fields brought onstream in recent years under a higher-cost development environment.

The exploration and production business recorded expenses of \$36.8 million in 2011, \$31.1 million in 2010 and \$25.5 million in 2009 for accretion on discounted abandonment liabilities. Because the abandonment liability is carried on the balance sheet at a discounted fair value, accretion must be recorded annually so that the liability will be recorded at full value at the projected time of abandonment. The \$5.7 million increase in accretion costs in 2011 compared to 2010 was attributable to a higher number of wells drilled in the current year in the Eagle Ford Shale and Montney areas and higher overall future estimated abandonment cost liabilities for Gulf of

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Mexico wells and synthetic oil operations at Syncrude. The \$5.6 million increase in accretion expense in 2010 compared to 2009 was due to additional wells drilled during the later year in several geographical areas and higher estimated abandonment costs for offshore operations in Malaysia and for Syncrude synthetic oil operations.

The effective income tax rate for exploration and production continuing operations was 53.8% in 2011, 41.7% in 2010 and 40.8% in 2009. The effective tax rate was significantly higher in 2011 than 2010 due to no tax benefit recorded on the impairment charge for the Azurite field and higher exploration and administrative expenses in certain foreign tax jurisdictions where no tax benefit can be currently recognized due to lack of sufficient revenue to realize a current or future benefit. Income tax expense in 2011 was reduced by a \$25.6 million benefit for expenses incurred in prior years in Block P, Malaysia. It was determined during 2011 that these expenses in Block P are deductible against taxable income generated in Block K Malaysia. Also, in 2011, the U.K. government enacted a 12% supplemental tax on oil and gas company profits in that country. This tax increase raised the Company's tax expense in 2011 by \$14.5 million, primarily to increase the recorded balance for deferred income taxes that will be paid in future years at the new higher rate. The effective tax rate is now 62% in the U.K. The overall effective income tax rate was slightly higher in 2010 than 2009 mostly due to tax barrels owed the government of Republic of the Congo under the production sharing agreement covering the Azurite field. More tax barrels were owed the government due to higher Azurite production levels in 2010. The effective tax rates in all three years exceeded the U.S. statutory tax rate of 35.0% due to higher overall foreign tax rates and exploration and other expenses in areas where current tax benefits cannot be recorded by the Company. Tax jurisdictions with no current tax benefit on expenses primarily include certain non-revenue generating areas in Malaysia, Suriname, Australia, Indonesia, Brunei, Cameroon and the Kurdistan region of Iraq. Each main exploration area in Malaysia is currently considered a distinct taxable entity and expenses in certain areas may not be used to offset revenues generated in other areas. No tax benefits have thus far been recognized for costs incurred for Block H, offshore Sabah, and Blocks PM 311/312, offshore Peninsula Malaysia.

At December 31, 2011, 34.5 million barrels of the Company's U.S. proved oil reserves and 40.2 billion cubic feet of U.S. proved natural gas reserves were undeveloped. More than 77% of the total U.S. undeveloped reserves (on a barrel of oil equivalent basis) are associated with the Company's Eagle Ford Shale operations in South Texas. Further drilling and facility construction are generally required to move the undeveloped reserves in the Eagle Ford Shale area to developed. In the Western Canadian Sedimentary Basin, total proved undeveloped natural gas reserves totaled 211.8 billion cubic feet, with the migration of these reserves, primarily in the Tupper and Tupper West areas, dependent on both development drilling and completion of processing and transportation facilities. In Block K Malaysia, all oil reserves of 14.7 million barrels for the Kakap field are undeveloped pending completion of facilities and development drilling directed by another company. Additionally, the Kikeh field had undeveloped oil reserves of 28.0 million barrels, which are subject to further development drilling before being moved to developed. Also in Malaysia, there were 98.3 billion cubic feet of undeveloped natural gas reserves at various fields offshore Sarawak at year-end 2011, which were held under this category pending completion of development drilling and facilities. The deepwaters of the Gulf of Mexico and the Schiehallion field in the U.K. North Sea accounted for additional proved undeveloped reserves of 9.2 million and 17.4 million equivalent barrels of oil, respectively, at December 31, 2011. On a worldwide basis, the Company spent approximately \$1.88 billion in 2011, \$1.27 billion in 2010 and \$1.34 billion in 2009 to develop proved reserves.

Refining and Marketing The Company's refining and marketing (R&M) operations generated earnings from continuing operations of \$190.3 million in 2011, \$130.6 million in 2010 and \$45.0 million in 2009. The R&M earnings improvement of \$59.7 million in 2011 compared to 2010 was mostly attributable to a \$0.042 per gallon improvement in retail fuel marketing sales margin in the U.S. and higher profits on merchandise sales at U.S. retail stations in 2011. The R&M earnings increase of \$85.6 million in 2010 compared to 2009 was driven primarily by a \$0.03 per gallon improvement in sales margin for retail fuel, partially offset by lower refining margins in the U.K. in 2010 compared to the prior year.

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The Company has announced its intention to divest its U.K. refining and marketing operations in 2012. The Meraux, Louisiana and Superior, Wisconsin refineries were sold in 2011 and are reported as discontinued operations.

The Company's United States R&M operations generated earnings from continuing operations of \$223.6 million in 2011, \$165.3 million in 2010 and \$65.5 million in 2009. U.S. R&M operations include two ethanol production facilities, along with retail and wholesale fuel marketing operations. The \$58.3 million increase in U.S. income in 2011 compared to 2010 was primarily attributable to more than a \$0.04 per gallon improvement in retail fuel margin partially offset by a reduction in gallons sold. Additionally, the Company had higher profits in 2011 on the sale of merchandise in this business. Total fuel sales volumes per station at Company operated sites in the U.S. averaged about 277,700 gallons per month during 2011, down 9% from the prior year. U.S. profits in 2011 included higher income from the Company's ethanol production facilities compared to 2010. The Hankinson plant operated for both years while the Hereford plant was open for most of 2011 only. Corn costs were higher in 2011 compared to 2010, but this increase was essentially offset by higher sales prices for ethanol and by-products, dried distillers grains and wet distillers grains, in the current year.

United States R&M profits from continuing operations increased \$99.8 million in 2010 compared to 2009. The 2010 increase was due to a \$0.03 per gallon higher fuel margin compared to 2009 in the retail marketing business. The retail marketing business had slightly lower volumes sold in 2010 compared to 2009. Fuel margins in the retail chain were hurt in 2009 by both lower demand for gasoline and diesel due to the weak economy and generally rising wholesale fuel costs caused by crude oil prices that rose gradually during the year.

United States refined product sales volumes (including discontinued operations) averaged 420,737 barrels per day in 2011, compared to 450,100 barrels per day in 2010 and 432,700 barrels per day in 2009. The decrease in 2011 was primarily due to the sale of the two U.S. refineries near the end of September 2011, plus lower gasoline volumes sold through the U.S. retail marketing business. The sales volume increase in 2010 compared to 2009 was mostly attributable to more finished products produced at the U.S. refineries compared to the prior year. Additionally 2010 included a full year of ethanol production from the Hankinson facility acquired in October 2009, compared to only three months of ethanol production in 2009. The retail marketing business added 29 stations in 2011, 51 stations in 2010 and 23 stations in 2009. The U.S. retail marketing network included 1,128 stations at year-end 2011.

United Kingdom R&M operations incurred a loss of \$33.3 million in 2011 compared to losses of \$34.7 million in 2010 and \$20.5 million in 2009. The loss in 2011 decreased from 2010 by \$1.4 million, primarily caused by slightly better refining margins in 2011 and higher throughput volumes in 2011 due to a two-month plant wide turnaround at the Milford Haven, Wales refinery in 2010. The loss in 2010 was higher than 2009 for U.K. R&M operations primarily due to weaker margins at the Milford Haven refinery and lower crude oil throughput caused by the refinery undergoing approximately a two-month plant-wide turnaround during 2010. U.K. refining margin was hurt by weak demand during the two-year period of 2009 and 2010. Soft demand for refined products in the U.K. and Western Europe led to an industry-wide oversupply of gasoline and diesel products in the area.

Unit margins in the United Kingdom averaged \$(0.67) per barrel in 2011, \$(1.47) per barrel in 2010 and \$(0.28) per barrel in 2009. Overall refined product sales volumes in the U.K. averaged 135,697 barrels per day in 2011, up 57% compared to 2010. The increase in sales volumes in 2011 was primarily due to downtime associated with a turnaround at the Milford Haven refinery in 2010. Sales volumes of refined products in the U.K. declined 16% to 86,657 barrels per day in 2010 compared to 2009, essentially due to the same refinery turnaround in 2010.

Corporate The after-tax costs of corporate activities, which include interest income, interest expense, foreign exchange gains and losses, and unallocated corporate overhead, were \$75.1 million in 2011, \$157.9 million in 2010 and \$23.0 million in 2009.

The net cost of corporate activities in 2011 was \$82.8 million lower than in 2010, primarily due to more favorable effects of foreign currency exchange, which was associated with transactions denominated in currencies other than the respective operation's predominant functional currency. The effect of foreign currency

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exchange after taxes was a gain of \$20.7 million in 2011 compared to a loss after taxes of \$58.1 million in 2010. The U.S. dollar generally strengthened against the Malaysian ringgit in 2011 after having weakened against this currency during 2010. The stronger U.S. currency in 2011 reduced the dollar cost of tax liabilities in Malaysia which are payable in the local currency. The Malaysian operation's functional currency is the U.S. dollar. Foreign currency transaction effects in the U.K. were also favorable in 2011 compared to the prior year. The corporate area also benefited in 2011 from higher interest income of \$3.2 million compared to 2010, principally due to higher levels of invested cash earning interest during the current year. Net interest expense, after capitalization of finance-related costs to development projects, was \$6.0 million higher in 2011 than 2010. This unfavorable variance was principally due to interest charged on certain tax assessments in Canada and lower amounts of interest capitalized to development projects in the latest year, primarily at the Tupper West area development in Western Canada where gas production started up in the first quarter of 2011. Administrative expenses associated with corporate activities were also higher in 2011 compared to 2010, primarily associated with additional costs for compensation and professional services.

The net cost of corporate activities rose \$134.9 million in 2010 compared to 2009. The most significant variance related to the effects of foreign currency exchange. The Company had after-tax losses from foreign currency exchange of \$58.1 million in 2010, while 2009 had after-tax gains of \$33.3 million. The foreign currency exchange loss in 2010 was primarily associated with a stronger Malaysian ringgit compared to the U.S. dollar. This led to costs associated with higher recorded future income tax liabilities, which are required to be paid in local currency. Foreign currency exchange losses were also experienced in the U.K. during 2010 caused by a stronger U.S. dollar compared to the British pound sterling. This led to higher costs for U.S. dollar denominated liabilities owed by the Company's U.K. refining and marketing business, which has a sterling functional currency. Additionally, 2009 benefited from interest income of \$42.0 million associated with a recovery of Federal royalties previously paid on certain deepwater Gulf of Mexico oil and natural gas production. Net interest expense, after capitalization of finance-related costs to development projects, was \$10.3 million higher in 2010 than 2009 mostly due to lower interest capitalized on oil and natural gas development projects during 2010. Corporate activities had higher administrative and depreciation expenses in 2010 than in 2009 of \$14.9 million and \$2.0 million, respectively, compared to 2009. The increase in administrative expense in 2010 was primarily associated with higher employee compensation costs. Income taxes associated with corporate activities in 2010 were significantly favorable to 2009 due to higher net pretax costs in the later year.

Discontinued Operations On September 30, 2011, the Company sold its Superior, Wisconsin refinery and related assets for \$214 million, plus certain capital expenditures between July 25, 2011 and the date of closing and the fair value of all associated hydrocarbon inventories at these locations. On October 1, 2011, the Company sold its Meraux, Louisiana refinery and related assets for \$325 million, plus the fair value of associated hydrocarbon inventories. The Company began to account for the Superior, Wisconsin and Meraux, Louisiana refineries and associated marketing assets as discontinued operations beginning in the third quarter 2011. All prior years presented have been reclassified to conform to this presentation of the Superior and Meraux operating results as discontinued operations.

Income from discontinued operations was \$131.8 million in 2011, including operating profits of \$113.1 million and an after-tax gain on sale of the two U.S. refineries of \$18.7 million. The after-tax gain from disposal of the two refineries included a gain on the Superior refinery (including associated inventories) of \$77.6 million and a loss on the Meraux refinery (including associated inventories) of \$58.9 million. The net gain on disposal was based on the selling prices of the refineries, plus the sales of all associated inventories at fair value, which was significantly above the last-in, first-out carrying value of the inventories sold. Operating profits in 2011 of \$113.1 million were significantly better than the 2010 operating profits of \$18.5 million due to much stronger refining margins in 2011.

Income from discontinued operations associated with the two U.S. refineries was a profit of \$18.5 million in 2010 compared to income of \$26.7 million in the 2009 period. The 2010 decline in results was primarily due to lower refining margins, and a nonrecurring income item in 2009 related to insurance settlements for Hurricane

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Katrina. The 2010 results benefited from higher crude oil throughput volumes compared to 2009. The 2009 results from discontinued operations also included income from Ecuador properties of \$97.1 million, which primarily arose from a gain on disposal of \$103.6 million.

Capital Expenditures

As shown in the selected financial data on page 23 of this Form 10-K report, capital expenditures from continuing operations, including exploration expenditures, were \$2.90 billion in 2011 compared to \$2.33 billion in 2010 and \$2.09 billion in 2009. These amounts excluded capital expenditures of \$48.1 million in 2011, \$117.3 million in 2010 and \$113.3 million in 2009 related to discontinued operations, which was primarily associated with two U.S. petroleum refineries sold during 2011. Capital expenditures included \$371.7 million, \$184.3 million and \$182.0 million, respectively, in 2011, 2010 and 2009 for exploration costs that were expensed. Capital expenditures for exploration and production continuing operations totaled \$2.77 billion in 2011, \$2.03 billion in 2010 and \$1.81 billion in 2009, representing 96%, 87% and 86%, respectively, of the Company's total capital expenditures from continuing operations for these years. Capital expenditures in 2011 for the E&P business included \$279.3 million for undeveloped lease acquisitions, \$23.5 million associated with a contract revision at the Azurite field, \$560.2 million of exploration activities and \$1.91 billion for development programs. Lease acquisitions were primarily associated with activities in the Eagle Ford Shale area of South Texas and exploration concessions in the Kurdistan region of Iraq. Exploration costs principally related to exploratory drilling at resource plays in North America, including the Eagle Ford Shale in South Texas and new areas in Southern Alberta, plus wildcat drilling activities in Brunei, Indonesia and Suriname. Development projects in 2011, primarily included spend of \$572.2 million at the Tupper West and Tupper natural gas areas in Western Canada; \$153.7 million for Seal heavy oil area activities; \$339.6 million for the Kikeh field in Malaysia; \$236.4 million for Sarawak SK Blocks 309/311 oil and gas projects offshore Malaysia; \$115.7 million for the Kakap field in Block K, offshore Sabah Malaysia; \$219.7 million for work in the Eagle Ford Shale; and \$73.9 million for synthetic oil operations at Syncrude.

E&P capital expenditures in 2010 included \$242.8 million for acquisition of undeveloped leases, which primarily included leases acquired in the Eagle Ford Shale area of South Texas and in the Tupper West area in Western Canada, \$470.0 million for exploration activities, \$1.30 billion for development projects, and \$22.0 million for acquisition of proved properties in Canada. Development expenditures included \$524.7 million at the Tupper West and Tupper West areas; \$46.8 million for deepwater fields in the Gulf of Mexico; \$166.8 million for Kikeh; \$160.4 million for natural gas and oil development activities in SK Blocks 309/311; \$58.1 million for Kakap; \$63.2 million for Syncrude; \$84.9 million for Western Canada heavy oil projects; \$126.5 million for development of the Azurite field in Republic of the Congo; and \$21.2 million for the Terra Nova and Hibernia oil fields, offshore Newfoundland. Exploration and production capital expenditures are shown by major operating area on page F-50 of this Form 10-K report.

Refining and marketing capital expenditures for continuing operations totaled \$122.3 million in 2011, \$290.1 million in 2010 and \$263.4 million in 2009. These amounts represented 4%, 12% and 13% of capital expenditures of the Company in 2011, 2010 and 2009, respectively. Total refining and marketing capital expenditures above excluded \$48.1 million, \$117.3 million and \$112.5 million in 2011, 2010 and 2009, respectively, for U.S. refineries sold in 2011, which are now classified as discontinued activities. Refining capital spending for discontinued operations during the three years primarily included costs at Meraux to reduce benzene production, construct a new laboratory, revamp the distillate hydrotreater and expand crude oil storage capacity, and at Superior to meet compliance with ultra-low sulfur diesel and Mobile Source Air Toxic requirements. Refining spend within continuing operations totaled \$14.7 million in 2011, \$59.8 million in 2010 and \$94.9 million in 2009. These expenditures related to the Milford Haven, Wales refinery, and in 2011 principally included minor capital improvements, while the majority of 2010 and 2009 spend related to costs to expand crude oil throughput capacity at Milford Haven to 135,000 barrels per day. Marketing expenditures amounted to \$84.9 million in 2011, \$185.4 million in 2010 and \$77.1 million in 2009. Marketing capital spending in 2011 was principally related to new station construction in the U.S. market. Marketing capital expenditures in 2010 were primarily associated with building new retail stations and acquiring land for new station sites in the U.S., while

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marketing capital expenditures in 2009 were primarily associated with new station builds and other improvements within the U.S. retail gasoline station network. The Company added 29 stations within its U.S. retail gasoline network in 2011, after adding 51 in 2010 and 23 in 2009. Capital expenditures related to ethanol operations in the U.S. totaled \$22.7 million in 2011, \$44.9 million in 2010 and \$91.4 million in 2009. The Company spent \$40.0 million in 2010 to acquire an unfinished ethanol production facility in Hereford, Texas. Construction of the Hereford facility was completed at an added cost of about \$25.1 million and the facility commenced operation near the end of the first quarter 2011. In 2009, the Company spent \$92.0 million to acquire an ethanol production facility and inventory in Hankinson, North Dakota. The Hankinson ethanol plant was financed with an \$82.0 million nonrecourse loan from the seller and a cash payment of \$10.0 million. The nonrecourse loan was repaid in 2010. See Note D of the consolidated financial statements for further details about these acquisitions.

Cash Flows

Operating activities Cash provided by operating activities was \$2.15 billion in 2011, \$3.13 billion in 2010 and \$1.86 billion in 2009. Cash provided by operating activities included cash from discontinued operations of \$145.5 million in 2011, \$100.5 million in 2010 and \$94.4 million in 2009. Cash provided by continuing operations in 2011 was \$1.03 billion less than 2010 primarily due to timing of cash collected and disbursed associated with changes in other working capital balances. Cash was primarily used to pay down accounts payable for crude oil feedstocks at formerly owned U.S. petroleum refineries and to pay income taxes in the U.S and Malaysia. Cash provided by continuing operations in 2010 was \$1.26 billion more than 2009 primarily due to a drawdown of working capital other than cash in the current year and higher income from continuing operations. The working capital reduction in 2010 included cash receipts of \$286.4 million related to recovery of federal royalties and associated interest income. Income associated with the royalty recovery was recorded in 2009, but the cash proceeds were collected in early 2010. Cash provided by operating activities was reduced by expenditures for abandonment of oil and gas properties totaling \$24.7 million in 2011, \$36.5 million in 2010 and \$48.7 million in 2009.

Investing activities Cash proceeds from property sales classified as continuing operations were \$27.8 million in 2011, \$2.2 million in 2010 and \$1.6 million in 2009. The 2011 proceeds primarily related to sale of gas storage assets in Spain. In 2011, the Company generated cash of \$950.0 million from sale of two U.S. refineries and associated marketing assets, including liquid inventories. The U.S. refineries' operating results and cash flow have been classified as discontinued operations in the Company's consolidated financial statements. Other investing activities for discontinued operations included capital expenditures of \$48.1 million in 2011, \$117.3 million in 2010 and \$113.3 million in 2009. Additionally, the two U.S. refineries which were sold used cash of \$1.5 million in 2011, \$37.5 million in 2010 and \$10.2 million in 2009 for maintenance turnarounds. During 2009, the Company generated cash of \$78.9 million from the sale of its 20% working interest in Block 16 in Ecuador. Operating results and cash flows associated with Ecuador operations have also been classified as discontinued operations. Property additions and dry hole costs for continuing operations used cash of \$2.62 billion in 2011, \$2.24 billion in 2010 and \$1.88 billion in 2009. Cash used to pay for capital expenditures increased each year compared to the prior year, with these variances essentially in line with changes in capital expenditures in each year. Cash of \$1.69 billion, \$2.39 billion and \$2.53 billion was spent in 2011, 2010 and 2009, respectively, to acquire Canadian government securities with maturities greater than 90 days at the time of purchase. Proceeds from maturities of Canadian government securities with maturities greater than 90 days at date of acquisition were \$1.77 billion in 2011, \$2.55 billion in 2010 and \$2.17 billion in 2009. Cash of \$5.4 million in 2011, \$61.4 million in 2010 and \$19.3 million in 2009 was used for turnarounds at the Milford Haven, Wales, refinery and Syncrude. The higher spend in 2010 was attributable to a plant-wide turnaround at Milford Haven.

Financing activities During 2011 and 2010, the Company used available cash flow to repay \$340.0 million and \$414.0 million, respectively, of debt. During 2009, the Company borrowed \$243.5 million under debt agreements primarily to fund a portion of the Company's development capital expenditures. The debt reduction in 2011 was accomplished with proceeds from sale of the two U.S. refineries. In 2009, the Company paid \$10.0 million to partially finance the acquisition of the Hankinson, North Dakota, ethanol plant; the remaining \$82.0 million acquisition price was financed with a seller-provided nonrecourse loan. This nonrecourse loan was fully

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repaid in 2010. Cash proceeds from stock option exercises and employee stock purchase plans, including income tax benefits on stock options, amounted to \$20.4 million in 2011, \$54.7 million in 2010 and \$16.9 million in 2009. In 2011, the Company used cash of \$7.9 million for fees and other expenses associated with renewing its primary \$1.5 billion committed credit facility that expires in June 2016. Also, in 2011 and 2010, cash of \$8.0 million and \$5.2 million, respectively, was used to pay statutory withholding taxes on stock-based incentive awards that vested with a net-of-tax payout. Cash used for dividends to stockholders was \$212.8 million in 2011, \$201.4 million in 2010 and \$190.8 million in 2009. The Company maintained its \$1.10 per share annualized dividend rate in 2011. It had previously raised its annualized dividend rate from \$1.00 per share to \$1.10 per share beginning in the third quarter of 2010.

Financial Condition

Year-end working capital (total current assets less total current liabilities) totaled \$622.7 million in 2011 and \$619.8 million in 2010. The current level of working capital does not fully reflect the Company's liquidity position as the carrying value for inventories under last-in, first-out accounting was \$580.2 million below fair value at December 31, 2011. Cash and cash equivalents at the end of 2011 totaled \$513.9 million compared to \$535.8 million at year-end 2010.

Long-term debt decreased by \$689.8 million during 2011 and totaled \$249.6 million at year-end 2011, representing 2.8% of total capital employed. The reduction in long-term debt in 2011 included a \$350.0 million reclassification of notes payable to a current liability. These notes mature in May 2012 and the Company is evaluating whether to sell replacement debt instruments. Long-term debt decreased by \$413.8 million in 2010. Stockholders' equity was \$8.78 billion at the end of 2011 compared to \$8.20 billion a year ago and \$7.35 billion at the end of 2009. A summary of transactions in stockholders' equity accounts is presented on page F-8 of this Form 10-K report.

Other changes in Murphy's year-end 2011 balance sheet compared to 2010 included an \$84.5 million reduction in the balance of short-term investments in Canadian government securities with maturities greater than 90 days at the time of purchase. The total investment in these Canadian government securities was \$532.1 million at year-end 2011 and \$616.6 million at year-end 2010. These slightly longer-term investments were purchased in each year because of a tight supply of shorter-term securities available for purchase in Canada. An \$86.9 million increase in accounts receivable in 2011 was primarily caused by higher sales prices for crude oil and finished products sold, and higher natural gas sales volumes sold on credit terms by the Company, but partially offset by the sale of U.S. refineries in 2011, which effectively reduced refined products volumes sold under credit arrangements in the U.S. in 2011. Inventory values were \$95.6 million less at year-end 2011 than in 2010 mostly due to lower levels of crude oil and refined products held in storage within downstream operations in the later year due to sale of two refineries in the U.S., but partially offset by higher costs for unsold crude oil production held in inventory in the current year. Prepaid expenses increased \$5.2 million in 2011 primarily due to prepaid income taxes in the U.S. at year-end 2011. Short-term deferred income tax assets were \$6.9 million higher at year-end 2011 compared to 2010 due mostly to more current temporary differences for expense deductions within U.K. downstream operations. Net property, plant and equipment increased by \$107.3 million in 2011 as a significant level of property additions during the year exceeded the amounts of depreciation, amortization and impairment expenses recorded during 2011. Goodwill decreased \$1.0 million in 2011 due to a weaker Canadian dollar exchange rate versus the U.S. dollar. Deferred charges and other assets decreased \$98.4 million mostly due to no deferred turnaround costs and other noncurrent assets remaining for the Meraux and Superior refineries following their sale in 2011. Current maturities of long-term debt at year-end 2011 was \$350.0 million higher than at the prior year-end due to a reclassification of \$350.0 million of outstanding notes payable to current based on their upcoming maturity in May 2012. Accounts payable decreased by \$296.9 million at year-end 2011 compared to 2010 primarily due to lower amounts owed for purchased crude oil feedstocks following the sale of the U.S. refineries in 2011. Income taxes payable was \$157.0 million lower at year-end 2011 than at the end of 2010, primarily due to less U.S. income tax liabilities owed in 2011. Other taxes payable at year-end 2011 was \$37.4 million lower than in 2010 mostly due to less value added taxes owed by the U.K. downstream operations

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and lower excise taxes owed by U.S. downstream operations. Other accrued liabilities increased by \$30.1 million at year-end 2011 mostly due to higher amounts owed for compensation and other operating costs. The current portion of deferred income tax liabilities increased \$5.3 million in 2011 due to higher short-term temporary differences for tax deductions in Canada in the current year. Noncurrent deferred income tax liabilities were \$17.9 million higher at year-end 2011 mostly due to accelerated tax depreciation associated with the Company's 2011 capital expenditures, primarily in Malaysia and Canada. The liability associated with future asset retirement obligations increased by \$60.3 million at year-end 2011 mostly due to higher estimated future costs to retire assets in the U.S. and Canada. Deferred credits and other liabilities were \$43.6 million more in 2011 compared to 2010 mostly due to higher noncurrent liabilities associated with postemployment benefit plans in the current year.

Murphy had commitments for future capital projects of approximately \$1.85 billion at December 31, 2011, including \$839.5 million for field development and future work commitments in Malaysia, \$149.7 million for costs to develop deepwater Gulf of Mexico fields, \$124.5 million for work in the Eagle Ford Shale and \$127.5 million for future work commitments offshore Brunei.

The primary sources of the Company's liquidity are internally generated funds, access to outside financing and working capital. The Company uses its internally generated funds to finance the major portion of its capital and other expenditures, but it also maintains lines of credit with banks and borrows as necessary to meet spending requirements. At December 31, 2011, the Company had access to a long-term committed credit facility in the amount of \$1.5 billion. There were no outstanding borrowings under the committed credit facility at year-end 2011. The most restrictive covenants under this committed credit facility limit the Company's long-term debt to capital ratio (as defined in the agreements) to 60%. The committed credit facility expires in 2016. At December 31, 2011, the Company had uncommitted bank credit lines of approximately \$400.0 million, but no borrowings were outstanding under these lines. The long-term debt to total capital ratio was 2.8% at year-end 2011. In September 2009, the Company filed a Form S-3 registration statement with the U.S. Securities and Exchange Commission which permits the offer and sale of debt and/or equity securities. The Company may use this shelf registration, if needed, in future years to raise debt or equity capital to fund operational requirements. This shelf registration expires in September 2012. Current financing arrangements are set forth more fully in Note F to the consolidated financial statements. Based on the anticipated level of capital expenditures the Company has budgeted during 2012, the Company anticipates that it will need to borrow under its long-term debt facility during 2012. The Company's ratio of earnings to fixed charges was 15.6 to 1 in 2011, 14.6 to 1 in 2010 and 14.5 to 1 in 2009.

Cash and invested cash are maintained in several operating locations outside the United States. At December 31, 2011, cash, cash equivalents and cash temporarily invested in Canadian government securities held outside the U.S. included approximately \$608 million in Canada, \$94 million in the U.K. and \$83 million in Malaysia. In certain cases, the Company could incur taxes or other costs should these cash balances be repatriated to the U.S. in future periods. This could occur due to withholding taxes and/or potential additional U.S. tax burden when less than the U.S. tax rate of 35% has been paid for cash taxes in foreign locations. A lower cash tax rate is often paid in foreign countries in the early years of operations when accelerated tax deductions exist to incent oil and gas investments; cash tax rates are generally higher in later years after accelerated tax deductions in early years are exhausted. Canada collects a 5% withholding tax on any cash repatriated to the U.S. See Note I of the consolidated financial statements for further information regarding potential tax expense that could be incurred upon distribution of foreign earnings back to the United States.

Environmental Matters

Murphy and other companies in the oil and gas industry are subject to numerous federal, state, local and foreign laws and regulations dealing with the environment. Virtually all operations of the Company are affected by laws and regulations covering environmental, health and safety matters. Compliance with existing and anticipated environmental regulations affects Murphy's overall cost of business, including capital costs to construct,

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maintain and upgrade equipment and facilities, and operating costs for ongoing environmental compliance. Murphy's competitive position may be impacted to the extent that regulatory requirements with respect to a particular production technology may give rise to costs that competitors might not bear. Environmental regulations have historically been subject to frequent change by regulatory authorities and these are expected to continue to evolve in the foreseeable future. The Company is unable to predict the ongoing cost of complying with these laws and regulations or the future impact of such regulations on its operations. Violation of federal or state environmental laws, regulations and permits can result in the imposition of significant civil and criminal penalties, injunctions and construction bans or delays. A discharge of hazardous substances into the environment could, to the extent such event is not insured, subject Murphy to substantial expense, including both the cost to comply with applicable regulations and claims by neighboring landowners and other third parties for any personal injury and property damage that might result.

Murphy allocates a portion of its capital expenditure program to comply with environmental laws and regulations, and such capital expenditures were \$103.7 million in 2011 and are projected to be \$74.7 million in 2012. The sale of U.S. refineries in 2011 will reduce future capital expenditures required to comply with environmental laws and regulations.

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

The U.S. Clean Air Act, which regulates air emissions

The U.S. Clean Water Act, which regulates discharges into U.S. waters

The U.S. Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which addresses liability for hazardous substance releases

The U.S. Federal Resource Conservation and Recovery Act (RCRA), which regulates solid waste and hazardous waste treatment, storage and disposal.

The U.S. Federal Oil Pollution Act of 1990 (OPA90), which addresses liability for discharges of oil into navigable waters of the United States

The U.S. Safe Drinking Water Act, which regulates disposal of wastewater into underground injection wells

The Federal Water Pollution Control Act of 1972 (FWPCA) also addressing discharge of pollutants into navigable waters

The Department of the Interior governing offshore oil and gas operations.

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

The European Union Trading Directive resulting in European Emissions Trading Scheme

These laws and their associated regulations establish limits on emissions and standards for quality of air, water and solid waste discharges. They also generally require permits for new or modified operations. Many states and foreign countries where the Company operates also have or are in the process of developing similar statutes and regulations governing air and water as well as the characteristics and composition of refined products, which in some cases impose or could impose additional and more stringent requirements. Murphy is also subject to certain acts and

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regulations, including legal and administrative proceedings, governing remediation of wastes or oil spills from current and past operations, which include but may not be limited to leaks from pipelines, underground storage tanks and general environmental operations. Murphy is actively engaged in the legislative and regulatory process, both nationally and internationally, in response to climate change issues and environmental and health related matters.

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Murphy's Environmental, Health, and Safety Committee, a standing committee of the Board of Directors, was created to oversee and monitor the Company's environmental, health, and safety (EHS) policies and practices. In February 2009, the Board approved a worldwide environmental, health, and safety policy (the EHS Policy), which is available on the Company's Web site. In addition to requiring that the Company comply with all applicable EHS laws and regulations, the EHS Policy includes a directive that the Company will continue to minimize the impact of its operations, products and services on the environment by implementing economically feasible projects that promote energy efficiency and use natural resources effectively.

CERCLA

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

The EPA currently considers Murphy to be a PRP at one Superfund site. The potential total cost to all parties to perform necessary remedial work at this site may be substantial. However, based on current negotiations and available information, the Company believes that it is a de minimis party as to ultimate responsibility at the Superfund site and as such, it has not recorded a liability for remedial costs. The Company could be required to bear a pro rata share of costs attributable to nonparticipating PRPs or could be assigned additional responsibility for remediation at this site or other Superfund sites. The Company believes that its share of the ultimate costs to remediate this Superfund site will be immaterial and will not have a material adverse effect on net income, financial condition or liquidity in a future period.

Waste

The Company currently owns or leases, and has in the past owned or leased, properties at which hazardous substances have been or are being handled. Although the Company has used operating and disposal practices that were standard in the industry at the time, hazardous substances may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes were not under Murphy's control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws Murphy could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. While some of these historical properties are in various stages of negotiation, investigation, and/or cleanup, Murphy is investigating the extent of any such liability and the availability of applicable defenses, including state funding for remediation, and believe costs related to these sites will not have a material adverse affect on its net income, financial condition or liquidity in a future period. Although certain environmental expenditures are likely to be recovered from other sources, no assurance can be given that future recoveries from these sources will occur. Therefore, the Company has not recorded a benefit for likely recoveries as of December 31, 2011.

RCRA and comparable state statutes govern the management and disposal of solid wastes, with the most stringent regulations applicable to treatment, storage or disposal of hazardous wastes. Murphy generates

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

Water

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

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

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

The Federal Water Pollution Control Act of 1972 (FWPCA) imposes restrictions and strict controls regarding the discharge of pollutants into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA imposes substantial potential liability for the costs of removal, remediation and damages. Murphy maintains wastewater discharge permits for its facilities where required pursuant to the FWPCA and comparable state laws. Murphy has also applied for all necessary permits to discharge storm water under such laws. The Company believes that compliance with existing permits and foreseeable new permit requirements will not have a material adverse effect on net income, financial condition or liquidity in a future period.

Murphy utilizes hydraulic fracturing technology for its exploration and production activities in Canada and the U.S. Murphy is actively engaged in exploration and production in the Eagle Ford Shale play in South Texas. On January 31, 2012, the Texas Railroad Commission finalized a rule that requires oil and gas operators to publicly disclose the chemicals and amount of water used in hydraulic fracturing of wells.

Air

Murphy's U.S. operations are subject to the Federal Clean Air Act and comparable state and local statutes. The Company believes that its operations are in substantial compliance with these statutes in all states in which it operates. Amendments to the Federal Clean Air Act enacted in 1990 required most refining operations in the U.S. to incur capital expenditures in order to meet air emission control standards developed by the EPA and state environmental agencies.

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Under the EPA's Clean Air Act authority, the National Petroleum Refinery (NPR) Initiative (Global Consent Decree) was used by the EPA to undertake at virtually all U.S. refineries an investigation of four marquee compliance areas, including: (i) New Source Review/Prevention of Significant Deterioration for fluidized catalytic cracking units, heaters and boilers; (ii) New Source Performance Standards for flares, sulfur recovery units, fuel gas combustion devices (including heaters and boilers); (iii) Leak Detection and Repair requirements; and (iv) Benzene National Emissions Standards for Hazardous Air Pollutants. Murphy began negotiations with the EPA in 2005, but was interrupted by the events of Hurricane Katrina. The states of Louisiana and Wisconsin are both parties to the NPR. Negotiations with EPA resumed in 2007 and were essentially completed in 2010. Under the Global Consent Decree, the Company paid a fine of \$1.25 million and committed to certain future capital improvements. The Company sold its two U.S. refineries in 2011.

The European Union has adopted an Emissions Trading Scheme in response to the Kyoto Protocol in order to achieve reductions in greenhouse gas emissions. Murphy's refinery at Milford Haven, Wales, currently has the most exposure to these requirements and may require purchase of emission allowances to maintain compliance with environmental permit requirements. These environmental expenditures are expensed as incurred. In 2011, Murphy was notified by the Environment Agency (EA) that it failed to surrender proper emission allowances, which Murphy self-reported to the EA in 2010. The Company is evaluating all available options regarding this matter.

Climate Change

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

The Company recognizes the importance of environmental stewardship as a core component of its mission as a responsible international energy company and has implemented sufficient disclosure controls and procedures to capture and process environmental, safety and climate-change related information. As a companion to Murphy's EHS Policy, the Company's Web site also contains a statement on climate change. Not only does this statement

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on climate change include Murphy's goal of reducing greenhouse gas emissions on an absolute basis while growing its upstream and certain downstream operations, the information on the Company's Web site describes actions already taken to move towards that goal. These efforts include incorporating climate change into the Company's planning processes, reducing emissions, pursuing new opportunities and engaging legislative and regulatory entities externally. In support of these efforts, worldwide greenhouse gas inventories have been conducted since 2001. Additionally, Murphy participates in the Massachusetts Institute of Technology (MIT) Joint Program on the Science and Policy of Global Change. The initiatives cited above demonstrate the Company's commitment regarding environmental issues, which are at the forefront of today's global public policy dialogue.

Other Matters

The Energy Independence and Security Act (EISA) was signed into law in December 2007. The EISA, through EPA regulation, requires refiners and gasoline blenders to obtain renewable fuel volume or representative trading credits as a percentage of their finished product production. EISA greatly increases the renewable fuels obligation defined in the Renewable Fuels Standard (RFS) which began in September 2007. Murphy is actively blending renewable fuel volumes through its retail and wholesale operations and trading corresponding credits known as Renewable Identification Numbers (RINs) to meet most of its obligation. On July 1, 2010, the RFS-2 standard came into effect requiring the blending/phase-in of ethanol, biodiesel, cellulosic and advanced renewable fuels. Murphy is meeting its obligations for RFS-2 primarily through the RINs system.

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

Safety Matters

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

Other Matters

Impact of inflation General inflation was moderate during the last three years in most countries where the Company operates; however, the Company's revenues and capital and operating costs are influenced to a larger extent by specific price changes in the oil and gas and allied industries than by changes in general inflation. Crude oil and petroleum product prices generally reflect the balance between supply and demand, with crude oil prices being particularly sensitive to OPEC production levels and/or attitudes of traders concerning supply and demand in the near future. Natural gas prices are affected by supply and demand, which are often affected by the weather and by the fact that delivery of gas is generally restricted to specific geographic areas. Prices for oil field goods and services have generally risen (with certain of these price increases such as drilling rig day rates having been significant at times) during the last few years primarily driven by high demand for such goods and services when oil and gas prices were strong. As noted earlier, oil and natural gas prices have been extremely volatile over the last several years. Oil prices were very strong in early to mid 2008, then fell precipitously in late 2008 and into early 2009, then have generally strengthened since that time. The prices for oil field goods and services

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generally rise in periods of higher oil prices and do not usually decline as significantly as oil and gas prices in a lower price environment. Should oil prices continue to rise in future periods, the Company anticipates that prices for certain oil field equipment and services could rise sharply. Due to the volatility of oil and natural gas prices, it is not possible to determine what effect these prices will have on the future cost of oil field goods and services.

Accounting changes and recent accounting pronouncements The Company adopted guidance issued by the Financial Accounting Standards Board (FASB) regarding accounting for transfers of financial assets effective January 1, 2010. This guidance makes the concept of a qualifying special-purpose entity as defined previously no longer relevant for accounting purposes. Therefore, formerly qualifying special-purpose entities were reevaluated for consolidation by reporting entities in accordance with the applicable consolidation guidance. This adoption of this guidance did not have a significant effect on the Company's consolidated financial statements.

The Company adopted, effective January 1, 2010, guidance issued by the FASB that requires a company to perform an analysis to determine whether its variable interests give it a controlling financial interest in a variable interest entity. The primary beneficiary of a variable interest entity has both the power to direct the activities of the entity that most significantly impact the entity's economic performance and the obligation to absorb potentially significant losses of the entity or the right to receive potentially significant benefits from the entity. A company is required to make ongoing reassessments of whether it is the primary beneficiary of a variable interest entity. This guidance also amended previous guidance for determining whether an entity is considered a variable interest entity. The adoption of this guidance did not have a significant effect on the Company's consolidated financial statements.

In July 2010, the FASB issued accounting guidance that expanded the disclosure requirements about financing receivables and the related allowance for credit losses. This guidance became effective for the Company at December 31, 2010. Because the Company has no significant financing receivables that extend beyond one year, the impact of this guidance did not have a significant effect on its consolidated financial statement disclosures.

The U.S. Securities and Exchange Commission (SEC) adopted revisions to oil and natural gas reserves reporting requirements which were effective for the Company at year-end 2009. In January 2010, the FASB issued guidance that aligned its oil and gas reserves reporting requirements and effective date with the SEC's guidance. The primary changes to reserves reporting included:

A revised definition of proved reserves, including the use of unweighted average oil and natural gas prices in effect at the beginning of each month during the year to compute such reserves,

Expanding the definition of oil and gas producing activities to include non-traditional and unconventional resources, which includes the Company's Canadian synthetic oil operations at Syncrude,

Allowing companies to voluntarily disclose probable and possible reserves in SEC filings,

Amending required proved reserve disclosures to include separate amounts for synthetic oil and gas,

Expanded disclosures of proved undeveloped reserves, including discussion of such proved undeveloped reserves five years old or more, and

Disclosure of the qualifications of the chief technical person who oversees the Company's overall reserve process.

The Company utilized the new SEC and FASB guidance at December 31, 2011, 2010 and 2009 to determine its proved reserves and to develop associated disclosures. The Company chose not to provide voluntary disclosures of probable and possible reserves in this Form 10-K.

In September 2011, the FASB issued an accounting standards update that simplifies the annual goodwill impairment assessment process by permitting a company to assess whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount before

applying the two-step goodwill impairment test.

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If a company concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the company would be required to conduct the current two-step goodwill impairment test. This change is effective for annual and interim goodwill impairment tests performed in fiscal years beginning in 2012. Early adoption is permitted. The Company does not expect the adoption of this standard in 2012 to have a significant effect on its consolidated financial statements.

In June 2011, the FASB issued an accounting standards update that only permits two options for presentation of Comprehensive Income. Comprehensive Income can be presented in (a) a single continuous Statement of Comprehensive Income, including total comprehensive income, the components of net income, and the components of other comprehensive income, or (b) in two separate but continuous statements for the Statement of Income and the Statement of Comprehensive Income. The new guidance is effective for the Company beginning in the first quarter of 2012. As in prior years, the Company expects to continue to present the Statements of Income and Comprehensive Income in two separate statements, and the adoption of this guidance in 2012 is not expected to have a significant effect on the Company's consolidated financial statements. In December 2011, the FASB deferred the requirement for reclassification adjustments from accumulated other comprehensive income to be measured and presented by line item in the Statements of Income and Comprehensive Income.

The United States Congress passed the Dodd-Frank Act in 2010. Among other requirements, the law requires companies in the oil and gas industry to disclose payments made to the U.S. Federal and all foreign governments. The SEC was directed to develop the reporting requirements in accordance with the law. The SEC has issued preliminary guidance and has received feedback thereon from interested parties. The preliminary rules indicated that payment disclosures would be required at a project level within the annual Form 10-K report beginning with the year ending December 31, 2012. The SEC has not issued final guidance regarding required disclosure. Therefore, it is expected that reporting will be delayed beyond year-end 2012. The Company cannot predict the final disclosure requirements that will be required by the SEC.

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

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

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lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of the Company's depreciation rates and the timing of settlement of asset retirement obligations. Downward reserve revisions can also lead to significant impairment expense. The Company cannot predict the type of oil and natural gas reserve revisions that will be required in future periods. The Company's proved reserves of oil and natural gas are presented on pages F-48 and F-49 of this Form 10-K. Murphy has utilized reliable geologic and engineering technology in 2011 to include proved undeveloped reserves more than one location from producing wells in the more developed portions of the Eagle Ford Shale. The study incorporated public and proprietary data from multiple sources and encompassed the entire basin. This included analysis of seismic data, well log data, test production and fluids properties to establish geologic consistency as well as significant statistical performance data yielding predictable and repeatable reserve estimates within certain analogous areas. These locations were limited to only those areas with both established geologic consistency and sufficient statistical performance data where such data could be demonstrated to provide reasonable certain results.

Oil proved reserves revisions

Positive proved oil reserve revisions in the U.S. in 2011 were primarily associated with better production at the Medusa field in the Gulf of Mexico. Positive 2011 oil revisions for Canada conventional operations were mostly attributable to better well performance at the Hibernia field, offshore Eastern Canada. Synthetic oil operations had positive reserve revisions in 2011 due to change in royalty rate. Positive oil revisions in 2011 in Malaysia were primarily at the Kikeh field caused by production performance. Positive oil revisions in the U.K. in 2011 were associated with the Schiehallion field which is being redeveloped by its owners. The negative revision in oil reserves in Republic of the Congo in 2011 was attributable to poor production results for wells in the field. The positive revision in U.S. proved oil reserves in 2010 was primarily associated with better than anticipated performance of wells at the Thunder Hawk and Medusa fields in the Gulf of Mexico. Better well performance at the Hibernia and Terra Nova fields led to favorable proved oil reserve revisions in Canada in 2010. Proved oil reserves for Canadian synthetic oil operations had a positive revision in 2010 primarily due to a lower royalty. The positive proved oil reserve revision in Malaysia in 2010 primarily related to better well performance at the Kikeh field. A positive proved oil reserve revision in Republic of the Congo in 2010 was attributable to improved terms under the production sharing agreement that allocated a larger share of production at the Azurite field to the account of the Company beginning in October 2010. A favorable oil reserve revision in 2009 in the United States was attributable to favorable performance of the Thunder Hawk and Front Runner fields and federal royalty relief for various deepwater fields. A favorable conventional oil revision in Canada in 2009 was caused by performance of the Terra Nova field and improved heavy oil pricing which added reserves in the Seal area. Due to changes in the SEC's definition of proved oil reserves, which were first effective as of December 31, 2009, synthetic oil reserves are now included as proved oil reserves. Consequently, total synthetic oil reserves as of January 1, 2009 of 131.6 million barrels were added to total oil reserves in 2009. The positive revision to synthetic oil reserves during 2009 was attributable to lower royalties compared to a year earlier. An unfavorable revision to oil reserves in Malaysia in 2009 was due to current-year drilling results for a well in the Kikeh field, along with reduced entitlements at Kikeh and West Patricia due to increased prices in 2009 compared to year-end 2008. Oil reserves in the U.K. reflected an unfavorable revision in 2009 because of an anticipated reduction in life expectancy for major equipment at the Schiehallion project.

Natural gas proved reserves revisions

Proved natural gas reserves in the U.S. had negative revisions in 2011 due to well performance being less than expected in early wells drilled in the gas-prone regions of the Eagle Ford Shale in South Texas. Positive gas reserve revisions in Canada in 2011 were primarily at the Tupper and Tupper West areas and these were based on better than anticipated well performance. Negative gas reserve revisions in Malaysia in 2011 were primarily due to higher sales prices which effectively reduced the entitlement percentage for

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future production at the Sarawak gas fields. Negative gas reserve revisions in the U.K. in 2011 were essentially caused by revised estimate of gas-cap volumes at the Mungo/Monan field. Proved natural gas reserves in the U.S. had positive revisions in 2010 due to better well performance at the Thunder Hawk and Mondo fields in the Gulf of Mexico. The positive gas reserve revision in Canada in 2010 was attributable to performance at various wells in the Tupper area of British Columbia. Proved reserves of natural gas in Malaysia were revised downward in 2010 due to higher prices leading to a lower future entitlement percentage for the Company. Positive gas reserve revisions in the U.K. in 2010 were attributable to better well performance at all gas producing fields. In 2009, a positive U.S. gas reserve revision was caused by favorable performance of the Thunder Hawk, Front Runner and Mondo NW fields as well as federal royalty relief for various deepwater fields. In Malaysia, a combination of increased entitlements due to pricing and drilling performance at the Sarawak gas project led to positive gas revisions in 2009. Gas reserves in the U.K. were favorably revised in 2009 because of the Amethyst field gas compression project and better Mungo field performance.

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

Based on the time required to complete further exploration and appraisal drilling in areas where hydrocarbons have been found but proved reserves have not been booked, dry hole expense may be recorded one or more years after the original drilling costs are incurred. In 2011, a dry hole was recorded for a well drilled in Republic of the Congo in 2009. A significant reduction in proved oil reserves at the Azurite field in the same MPS block during 2011 reduced the likelihood of this well being produced in future years. In 2010, a dry hole was recorded for a well in the North Sea that was drilled in 2008. Extensive evaluations of this oil discovery determined in 2010 that recovery of hydrocarbons was not economical in the current price environment. There were no dry holes in 2009 that were drilled in prior years.

Impairment of long-lived assets The Company continually monitors its long-lived assets recorded in Property, Plant and Equipment and Goodwill in the Consolidated Balance Sheet to make sure that they are fairly presented. The Company must evaluate its properties for potential impairment when circumstances indicate that the carrying value of an asset may not be recoverable from future cash flows. Goodwill is evaluated for impairment at least annually. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the amount of oil and natural gas that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, future capital and abandonment costs, future margins on refined products produced and sold, and future inflation levels. The need to test a property for impairment can be based on several factors, including but not limited to a significant reduction in sales prices for oil and/or natural gas, unfavorable reserve revisions, expected deterioration of future refining and/or marketing margins for refined products, or other changes to contracts, environmental regulations or tax laws. All of these same factors must be considered when evaluating a property's carrying value for possible impairment.

In making its impairment assessments involving exploration and production property and equipment, the Company must make a number of projections involving future oil and natural gas sales prices, future

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production volumes, and future capital and operating costs. Due to the volatility of world oil and gas markets, the actual sales prices for oil and natural gas have often been quite different from the Company's projections. Estimates of future oil and gas production and sales volumes are based on a combination of proved and risked probable and possible reserves. Although the estimation of reserves and future production is uncertain, the Company believes that its estimates are reasonable; however, there have been cases where actual production volumes were higher or lower than projected and the timing was different than the original projection. The Company adjusts reserves and production estimates as new information becomes available. The Company generally projects future costs by using historical costs adjusted for both assumed long-term inflation rates and known or expected changes in future operations. Although the projected future costs are considered to be reasonable, at times, costs have been higher or lower than originally estimated. In assessing potential impairment involving refining and marketing assets, the Company evaluates its properties when circumstances indicate that carrying value of an asset may not be recoverable from future cash flows. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events, which include projections of future margins, future capital expenditures and future operating expenses. Future marketing or operating decisions, such as closing or selling certain assets, and future regulatory or tax changes could also impact the Company's conclusion about potential asset impairment. Impairment expense of \$368.6 million was recognized in 2011 to reduce the carrying value of the Azurite oil field, offshore Republic of the Congo, to fair value. The expense was necessitated by a significant year-end 2011 reduction of proved reserves at this field which was caused by poor well performance. Additionally, an impairment expense of \$5.2 million was recorded in 2009 to write-off the remaining carrying value of one underperforming natural gas field in the Gulf of Mexico. Based on an evaluation of expected future cash flows from properties at year-end 2011, the Company does not believe it had any other significant properties with carrying values that were impaired at that date. The expected future sales prices for crude oil and natural gas used in the evaluation were based on quoted future prices for the respective production periods. These quoted prices often reflect higher expected prices for oil and natural gas in the future compared to the existing spot prices at the time of assessment. If quoted prices for future years had been lower, the smaller projected cash flows for properties could have led to significant impairment charges being recorded for certain properties in 2011. In addition, one or a combination of factors such as lower future sales prices, lower future production, higher future costs, lower future margins on refining and marketing sales, or the actions of government authorities could lead to impairment expenses in future periods. Based on these unknown future factors as described herein, the Company cannot predict the amount or timing of impairment expenses that may be recorded in the future.

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

Accounting for retirement and postretirement benefit plans Murphy Oil and certain of its subsidiaries maintain defined benefit retirement plans covering most of its full-time employees. The Company also sponsors health care and life insurance benefit plans covering most retired U.S. employees. The expense

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associated with these plans is determined by management based on a number of assumptions and with consultation assistance from qualified third-party actuaries. The most important of these assumptions for the retirement plans involve the discount rate used to measure future plan obligations and the expected long-term rate of return on plan assets. For the retiree medical and insurance plans, the most important assumptions are the discount rate for future plan obligations and the health care cost trend rate. Discount rates are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate which is the basis for selecting the discount rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Anticipated health care cost trend rates are determined based on prior experience of the Company and an assessment of near-term and long-term trends for medical and drug costs. Based on bond yields at year-end 2011, the Company has used a discount rate of 4.87% at year-end 2011 and beyond for the primary U.S. plans. Although the Company presently assumes a return on plan assets of 6.50% for the primary U.S. plan, it periodically reconsiders the appropriateness of this and other key assumptions. The smoothing effect of current accounting regulations tends to buffer the current year's pension expense from wide swings in liabilities and asset valuations. The Company's normal annual retirement and postretirement plan expenses are expected to increase slightly in 2012 compared to 2011 based on the effects of a growing employee base. In 2011, the Company paid \$38.4 million into various retirement plans and \$4.1 million into postretirement plans. In 2012, the Company is expecting to fund payments of approximately \$35.5 million into various retirement plans and \$5.8 million for postretirement plans. The Company could be required to make additional and more significant funding payments to retirement plans in future years. Future required payments and the amount of liabilities recorded on the balance sheet associated with the plans could be unfavorably affected if the discount rate declines, the actual return on plan assets falls below the assumed return, or the health care cost trend rate increase is higher than expected. As described above, the Company's retirement and postretirement expenses are sensitive to certain assumptions, primarily related to discount rates and assumed return on plan assets. A 0.5% decline in the discount rate would increase 2012 annual retirement and postretirement expenses by \$6.1 million and \$0.9 million, respectively, and a 0.5% decline in the assumed rate of return on plan assets would increase 2012 retirement expense by \$2.4 million.

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

Contractual obligations and guarantees The Company is obligated to make future cash payments under borrowing arrangements, operating leases, purchase obligations primarily associated with existing capital expenditure commitments, and other long-term liabilities. In addition, the Company expects to extend certain operating leases beyond the minimum contractual period. Total payments due after 2012 under such contractual obligations and arrangements are shown below.

(Millions of dollars)	Total	Amount of Obligations			
		2012	2013-2014	2015-2016	After 2016
Total debt including current maturities	\$ 599.6	350.0	0.1	0.1	249.4
Operating leases	826.3	161.6	265.2	150.2	249.3
Purchase obligations	2,513.4	1,967.4	478.7	47.4	19.9
Other long-term liabilities	1,277.3	98.6	120.7	229.5	828.5
Total	\$ 5,216.6	2,577.6	864.7	427.2	1,347.1

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

In the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide financial guarantees or letters of credit that may be drawn upon if the Company fails to perform under those contracts. The amounts of commitments as of December 31, 2011 that expire in future periods are shown below.

<i>(Millions of dollars)</i>	Total	Amount of Commitments			
		2012	2013-2014	2015-2016	After 2016
Financial guarantees	\$ 7.8		3.2	1.2	3.4
Letters of credit	162.9	155.7	7.2		
Total	\$ 170.7	155.7	10.4	1.2	3.4

Material off-balance sheet arrangements The Company occasionally utilizes off-balance sheet arrangements for operational or funding purposes. The most significant of these arrangements at year-end 2011 included operating leases of floating, production, storage and offloading vessels (FPSO) for the Kikeh and Azurite oil fields, operating leases for production facilities at the Thunder Hawk and West Patricia fields and for certain land and/or fueling stations in the U.K. and U.S., and natural gas transportation contracts in Western Canada. The leases call for future monthly net lease payments through 2016 at Kikeh and Azurite, through 2014 at Thunder Hawk and through 2012 at West Patricia. The U.K. and U.S. fueling stations require monthly payments mostly over the next 20 years. The Western Canada transportation contracts require minimum monthly payments through 2018. Future required minimum annual payments under these arrangements are included in the contractual obligation table shown on the preceding page.

Outlook

Prices for the Company's primary products are often quite volatile. The price for crude oil is primarily affected by the level of demand for energy. In January 2012, West Texas Intermediate crude oil traded in a band between \$98 and \$103 per barrel. NYMEX natural gas traded in a band of \$2.30 to \$3.10 per MMBTU during this same time. U.S. retail marketing margins in January 2011 were squeezed by higher wholesale fuel costs during this period. The Company continually monitors the prices for its main products and often alters its operations and spending based on these prices.

The Company's capital expenditure budget for 2012 was prepared during the fall of 2011 and based on this budget capital expenditures are expected to be higher than 2011 levels. Since the budget was approved by the Company's Board of Directors, crude oil prices have generally been above the levels assumed in the 2012 budget, but North American natural gas prices have generally trailed the budgeted prices. Based on a recent review of capital expenditure projects, capital expenditures in 2012 are projected to total approximately \$3.53 billion. Of this amount, \$3.32 billion or about 94%, is allocated for the exploration and production program. Geographically, E&P capital is spread approximately as follows: 33% for the United States, 37% for Malaysia, 23% for Canada and 7% for all other areas. Spending in the U.S. is primarily associated with development and exploration programs in the Eagle Ford Shale area of South Texas. In Malaysia, the majority of the spending is for continued development of the Kikeh and Kakap fields in Block K and oil development projects offshore Sarawak in Blocks SK 309 and SK 311. Approximately 40% of Canadian spending in 2012 will relate to natural gas development activities at the Tupper and Tupper West areas in Western Canada, with most of the remainder to be spent on continued development of the Seal heavy oil area and at Syncrude. Refining and marketing expenditures in 2012 are budgeted at about \$200 million, or 6% of the Company total, including funds for construction of additional U.S. retail gasoline stations. Capital and other expenditures will be routinely reviewed

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during 2012 and planned capital expenditures may be adjusted to reflect differences between budgeted and actual cash flow during the year. Capital expenditures may also be affected by asset purchases, which often are not anticipated at the time the Budget is prepared.

The Company will primarily fund its capital program in 2012 using operating cash flow, but will supplement funding where necessary using borrowings under available credit facilities. The Company's 2012 budget calls for borrowings of long-term debt during the year to fund a portion of the capital program. If oil and/or natural gas prices weaken, actual cash flow generated from operations could be reduced such that higher than anticipated borrowings might be required during the year to maintain funding of the Company's ongoing development projects.

The Company currently expects production in 2012 to average about 200,000 barrels of oil equivalent per day. A key assumption in projecting the level of 2012 Company production is the anticipated ramp up of natural gas production in Western Canada. Should Canadian natural gas prices continue to remain weak throughout 2012, the Company may elect to delay its development drilling in the prolific Montney gas area. Other key assumptions necessary to achieve the anticipated 2012 production levels include continued reliability of production at significant operations such as Kikeh, Syncrude, Hibernia and Terra Nova, the continued demand for natural gas from our offshore Malaysia fields, and the continued favorable results of ongoing development activities at the Eagle Ford Shale area in South Texas.

The Company announced in 2010 that it planned to exit the U.K. refining and marketing business. The sale process for this U.K. business continues to progress in early 2012.

Forward-Looking Statements

This Form 10-K contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. These statements, which express management's current views concerning future events or results, are subject to inherent risks and uncertainties. Factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements include, but are not limited to, the volatility and level of crude oil and natural gas prices, the level and success rate of our exploration programs, our ability to maintain production rates and replace reserves, customer demand for our products, political and regulatory instability, and uncontrollable natural hazards. For further discussion of risk factors, see Item 1A. Risk Factors, which begins on page 15 of this Annual Report on Form 10-K. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to market risks associated with interest rates, prices of crude oil, natural gas and petroleum products, and foreign currency exchange rates. As described in Note L to the consolidated financial statements, Murphy makes limited use of derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions.

There were short-term commodity derivative contracts in place at December 31, 2011 to hedge the purchase price of about 8.0 million bushels of corn and the sales prices of about 1.1 million equivalent bushels of wet and dried distillers grain at the Company's ethanol production facilities in Hankinson, North Dakota, and Hereford, Texas. Additionally, the Company had outstanding derivative contracts to price protect the historical cost of about 2.9 million bushels of corn inventories expected to be processed at the Company's ethanol plants. A 10% increase in the respective benchmark price of these commodities would have increased the recorded net liability associated with these derivative contracts by approximately \$2.0 million, while a 10% decrease would have decreased the recorded net liability by a similar amount. Changes in the fair value of these derivative contracts generally offset the changes in the value for an equivalent volume of these feedstocks.

There were short-term derivative foreign exchange contracts in place at December 31, 2011 to hedge the value of U.S. dollars against two foreign currencies. A 10% strengthening of the U.S. dollar against these foreign

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currencies would have increased the recorded net liability associated with these contracts by approximately \$17.6 million, while a 10% weakening of the U.S. dollar would have reduced the recorded net liability by approximately \$6.3 million. Changes in the fair value of these derivative contracts generally offset the financial statement impact of an equivalent volume of foreign currency exposures associated with other assets and/or liabilities.

There were short-term derivative interest rate contracts in place at December 31, 2011 to hedge fluctuations in cash flows of anticipated future semi-annual interest payments attributable to changes in the benchmark interest rate. A 10% increase in the respective interest rate would have reduced the recorded liability associated with these derivative contracts by approximately \$5.8 million, while a 10% decrease would have increased the recorded liability by a similar amount.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages F-1 through F-55, which follow page 60 of this Form 10-K report.

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

None

Item 9A. CONTROLS AND PROCEDURES

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

Based on their evaluation, with the participation of the Company's management, as of December 31, 2011, the principal executive officer and principal financial officer of Murphy Oil Corporation have concluded that the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective to ensure that the information required to be disclosed by Murphy Oil Corporation in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Murphy's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Management has conducted an evaluation of the effectiveness of our internal control over financial reporting based on the criteria set forth in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, management has concluded that our internal control over financial reporting was effective as of December 31, 2011. Our report is included on page F-1 of the annual report. KPMG LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2011 and their report is included on page F-3 of this annual report.

There were no changes in the Company's internal controls over financial reporting that occurred during the fourth quarter of 2011 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. OTHER INFORMATION

None

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PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Certain information regarding executive officers of the Company is included on pages 20 and 21 of this Form 10-K report. Other information required by this item is incorporated by reference to the Registrant's definitive Proxy Statement for the Annual Meeting of Stockholders on May 9, 2012 under the captions "Election of Directors" and "Committees."

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

Item 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 9, 2012 under the captions "Compensation Discussion and Analysis" and "Compensation of Directors," and in various compensation schedules.

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

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 9, 2012 under the captions "Security Ownership of Certain Beneficial Owners," "Security Ownership of Management," and "Equity Compensation Plan Information."

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

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 9, 2012 under the caption "Election of Directors."

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 9, 2012 under the caption "Audit Committee Report."

Table of Contents**PART IV****Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES**

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

	Page No.
<u>Report of Management Consolidated Financial Statements</u>	F-1
<u>Report of Management Internal Control Over Financial Reporting</u>	F-1
<u>Report of Independent Registered Public Accounting Firm</u>	F-2
<u>Report of Independent Registered Public Accounting Firm</u>	F-3
<u>Consolidated Balance Sheets</u>	F-4
<u>Consolidated Statements of Income</u>	F-5
<u>Consolidated Statements of Comprehensive Income</u>	F-6
<u>Consolidated Statements of Cash Flows</u>	F-7
<u>Consolidated Statements of Stockholders Equity</u>	F-8
<u>Notes to Consolidated Financial Statements</u>	F-9
<u>Supplemental Oil and Gas Information (unaudited)</u>	F-46
<u>Supplemental Quarterly Information (unaudited)</u>	F-55

2. Financial Statement Schedules

<u>Schedule II Valuation Accounts and Reserves</u>	F-56
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All other financial statement schedules are omitted because either they are not applicable or the required information is included in the consolidated financial statements or notes thereto.

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

Exhibit

No.		Incorporated by Reference to
2.1	Asset Purchase Agreement between Calumet Specialty Products Partners, L.P. and Murphy Oil Corporation covering the Superior, Wisconsin refinery	Exhibit 2.1 of Murphy's Form 10-Q report filed November 4, 2011
2.2	Asset Purchase Agreement between Valero Refining-Meraux LLC and Murphy Oil Corporation covering the Meraux, Louisiana refinery	Exhibit 2.2 of Murphy's Form 10-Q report filed November 4, 2011
3.1	Certificate of Incorporation of Murphy Oil Corporation as amended, effective May 11, 2005	Exhibit 3.1 of Murphy's Form 10-K report filed February 28, 2011
3.2	By-Laws of Murphy Oil Corporation as amended effective February 3, 2010	Exhibit 3.2 of Murphy's Form 8-K report filed February 4, 2010
4	Instruments Defining the Rights of Security Holders. Murphy is party to several long-term debt instruments in addition to those in Exhibit 4.1 and 4.2, none of which authorizes securities exceeding 10% of the total consolidated assets of Murphy and its subsidiaries. Pursuant to Regulation S-K, item	

601(b), paragraph 4(iii)(A), Murphy agrees to furnish a copy of each such instrument to the Securities and Exchange Commission upon request.

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Exhibit

No.	Incorporated by Reference to	
4.1	Form of Second Supplemental Indenture between Murphy Oil Corporation and SunTrust Bank, as Trustee	Exhibit 4.1 of Murphy s Form 10-K report for the year ended December 31, 2008
4.2	Form of Indenture and Form of Supplemental Indenture between Murphy Oil Corporation and SunTrust Bank as Trustee	Exhibit 4.2 of Murphy s Form 10-K report for the year ended December 31, 2009
10.1	1992 Stock Incentive Plan as amended May 14, 1997, December 1, 1999, May 14, 2003 and December 7, 2005	Exhibit 10.1 of Murphy s Form 10-K report for the year ended December 31, 2010
10.2	2007 Long-Term Incentive Plan	Exhibit 10.1 of Murphy s Form 8-K report filed April 24, 2007
10.3	Employee Stock Purchase Plan as amended May 9, 2007	Exhibit C of Murphy s definitive proxy statement (Definitive 14A) dated March 30, 2007
10.4	2008 Stock Plan for Non-Employee Directors, as approved by shareholders on May 14, 2008	Form S-8 report filed February 5, 2009
*12.1	Computation of Ratio of Earnings to Fixed Charges	
*13	2011 Annual Report to Security Holders	
*21	Subsidiaries of the Registrant	
*23.1	Consent of Independent Registered Public Accounting Firm	
*23.2	Consent of Ryder Scott Company, L.P.	
*31.1	Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
*31.2	Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
32	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	See footnote ¹ on page 59.
99.1	Form of employee stock option	Exhibit 99.1 of Murphy s Form 10-K report for the year ended December 31, 2009
99.2	Form of performance-based employee restricted stock unit grant agreement	Exhibit 99.2 of Murphy s Form 10-K report for the year ended December 31, 2008
99.3	Form of non-employee director stock option	Exhibit 99.3 of Murphy s Form 10-K report for the year ended December 31, 2010
99.4	Form of non-employee director restricted stock award	Exhibit 99.4 of Murphy s Form 10-K report for the year ended December 31, 2006
99.5	Form of non-employee director restricted stock unit award	Exhibit 99.5 of Murphy s Form 10-K report for the year ended December 31, 2008

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Exhibit

No.		Incorporated by Reference to
*99.6	Report of Ryder Scott Company, L.P.	
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema Document	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document	
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	

¹ These certifications will not be deemed to be filed with the Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

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SIGNATURES

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

MURPHY OIL CORPORATION

By **DAVID M. WOOD** Date: February 28, 2012
David M. Wood, President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 28, 2012 by the following persons on behalf of the registrant and in the capacities indicated.

WILLIAM C. NOLAN, JR. William C. Nolan, Jr., Chairman and Director	WALENTIN MIROSH Walentin Mirosh, Director
DAVID M. WOOD David M. Wood, President and Chief Executive Officer and Director (Principal Executive Officer)	R. MADISON MURPHY R. Madison Murphy, Director
FRANK W. BLUE Frank W. Blue, Director	NEAL E. SCHMALE Neal E. Schmale, Director
STEVEN A. COSSÉ Steven A. Cossé, Director	DAVID J. H. SMITH David J. H. Smith, Director
CLAIBORNE P. DEMING Claiborne P. Deming, Director	CAROLINE G. THEUS Caroline G. Theus, Director
ROBERT A. HERMES Robert A. Hermes, Director	KEVIN G. FITZGERALD Kevin G. Fitzgerald, Executive Vice President and Chief Financial Officer (Principal Financial Officer)
JAMES V. KELLEY James V. Kelley, Director	JOHN W. ECKART John W. Eckart Senior Vice President and Controller

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REPORT OF MANAGEMENT CONSOLIDATED FINANCIAL STATEMENTS

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

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

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

REPORT OF MANAGEMENT INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Management has conducted an evaluation of the effectiveness of our internal control over financial reporting based on the criteria set forth in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2011.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of Murphy Oil Corporation:

We have audited the accompanying consolidated balance sheets of Murphy Oil Corporation and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, cash flows and stockholders' equity for each of the years in the three-year period ended December 31, 2011. In connection with our audits of the consolidated financial statements, we also have audited financial statement Schedule II. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Murphy Oil Corporation and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Murphy Oil Corporation's internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2012 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas

February 28, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of Murphy Oil Corporation:

We have audited Murphy Oil Corporation's internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Murphy Oil Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Report of Management - Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Murphy Oil Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Murphy Oil Corporation as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, cash flows and stockholders' equity for each of the years in the three-year period ended December 31, 2011, and our report dated February 28, 2012 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas

February 28, 2012

Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****CONSOLIDATED BALANCE SHEETS**

December 31 (<i>Thousands of dollars</i>)	2011	2010
Assets		
Current assets		
Cash and cash equivalents	\$ 513,873	535,825
Canadian government securities with maturities greater than 90 days at the date of acquisition	532,093	616,558
Accounts receivable, less allowance for doubtful accounts of \$7,892 in 2011 and \$7,954 in 2010	1,554,184	1,467,311
Inventories, at lower of cost or market		
Crude oil and blend stocks	189,320	147,256
Finished products	254,880	388,162
Materials and supplies	222,438	226,795
Prepaid expenses	93,397	88,241
Deferred income taxes	87,486	80,545
Total current assets	3,447,671	3,550,693
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of \$6,861,494 in 2011 and \$6,040,996 in 2010	10,475,149	10,367,847
Goodwill	41,863	42,850
Deferred charges and other assets	173,455	271,853
Total assets	\$ 14,138,138	14,233,243
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long-term debt	\$ 350,005	41
Accounts payable	1,941,008	2,237,920
Income taxes payable	201,784	358,764
Other taxes payable	169,535	206,951
Other accrued liabilities	140,024	109,918
Deferred income taxes	22,572	17,316
Total current liabilities	2,824,928	2,930,910
Long-term debt	249,553	939,350
Deferred income taxes	1,230,111	1,212,213
Asset retirement obligations	615,545	555,248
Deferred credits and other liabilities	439,604	395,972
Stockholders' equity		
Cumulative Preferred Stock, par \$100, authorized 400,000 shares, none issued	0	0
Common Stock, par \$1.00, authorized 450,000,000 shares at December 31, 2011 and 2010, issued 193,909,200 shares at December 31, 2011 and 193,293,526 shares at December 31, 2010	193,909	193,294
Capital in excess of par value	817,974	767,762
Retained earnings	7,460,942	6,800,992
Accumulated other comprehensive income	310,420	449,428
Treasury stock	(4,848)	(11,926)
Total stockholders' equity	8,778,397	8,199,550
Total liabilities and stockholders' equity	\$ 14,138,138	14,233,243

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

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Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****CONSOLIDATED STATEMENTS OF INCOME**

Years Ended December 31 (<i>Thousands of dollars except per share amounts</i>)	2011	2010*	2009*
Revenues			
Sales and other operating revenues	\$ 27,689,332	20,225,764	16,800,972
Gain on sale of assets	22,679	884	3,732
Interest and other income (loss)	33,538	(56,930)	90,502
Total revenues	27,745,549	20,169,718	16,895,206
Costs and Expenses			
Crude oil and product purchases	21,875,297	15,351,318	12,821,305
Operating expenses	1,993,346	1,678,515	1,350,658
Exploration expenses, including undeveloped lease amortization	489,862	292,264	265,172
Selling and general expenses	301,005	259,215	212,376
Depreciation, depletion and amortization	1,093,406	1,114,529	870,999
Impairment of properties	368,600	0	5,240
Accretion of asset retirement obligations	37,701	31,857	26,154
Redetermination of Terra Nova working interest	(5,351)	18,582	83,498
Interest expense	55,831	53,172	53,005
Interest capitalized	(15,131)	(18,444)	(28,614)
Total costs and expenses	26,194,566	18,781,008	15,659,793
Income from continuing operations before income taxes	1,550,983	1,388,710	1,235,413
Income tax expense	810,051	609,151	521,559
Income from continuing operations	740,932	779,559	713,854
Income from discontinued operations, net of income taxes	131,770	18,522	123,767
Net Income	\$ 872,702	798,081	837,621
Income per Common Share Basic			
Income from continuing operations	\$ 3.83	4.06	3.74
Income from discontinued operations	0.68	0.10	0.65
Net Income Basic	\$ 4.51	4.16	4.39
Income per Common Share Diluted			
Income from continuing operations	\$ 3.81	4.03	3.71
Income from discontinued operations	0.68	0.10	0.64
Net Income Diluted	\$ 4.49	4.13	4.35
Average Common shares outstanding basic	193,409,621	191,830,357	190,767,077
Average Common shares outstanding diluted	194,512,402	193,157,814	192,468,450

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

* Reclassified to conform to current presentation.

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Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

Years Ended December 31 (<i>Thousands of dollars</i>)	2011	2010	2009
Net income	\$ 872,702	798,081	837,621
Other comprehensive income (loss), net of tax			
Net gain (loss) from foreign currency translation	(91,247)	165,940	375,951
Retirement and postretirement benefit plan adjustments	(30,909)	(3,699)	(1,067)
Loss deferred on interest rate hedges	(16,852)	0	0
Other comprehensive income (loss)	(139,008)	162,241	374,884
Comprehensive Income	\$ 733,694	960,322	1,212,505

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

Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****CONSOLIDATED STATEMENTS OF CASH FLOWS**

Years Ended December 31 (<i>Thousands of dollars</i>)	2011	2010 ¹	2009 ¹
Operating Activities			
Net income	\$ 872,702	798,081	837,621
Adjustments to reconcile net income to net cash provided by operating activities			
Income from discontinued operations	(131,770)	(18,522)	(123,767)
Depreciation, depletion and amortization	1,093,406	1,114,529	870,999
Impairment of long-lived assets	368,600	0	5,240
Amortization of deferred major repair costs	23,076	15,561	7,348
Expenditures for asset retirements	(24,692)	(36,506)	(48,694)
Dry hole costs	250,954	90,125	125,244
Amortization of undeveloped leases	118,211	108,026	83,213
Accretion of asset retirement obligations	37,701	31,857	26,154
Deferred and noncurrent income tax charges	171,565	135,225	95,245
Pretax gains from disposition of assets	(22,679)	(884)	(3,709)
Net decrease (increase) in noncash operating working capital	(825,154)	639,566	(194,690)
Other operating activities net	67,955	151,012	90,001
Net cash provided by continuing operations	1,999,875	3,028,070	1,770,205
Net cash provided by discontinued operations	145,510	100,488	94,428
Net cash provided by operating activities	2,145,385	3,128,558	1,864,633
Investing Activities			
Property additions and dry hole costs	(2,623,407)	(2,199,049)	(1,866,114)
Acquisition of ethanol plants ²	0	(40,000)	(10,000)
Proceeds from sale of property, plant and equipment	27,776	2,189	1,616
Expenditures for major repairs	(5,409)	(61,387)	(19,252)
Purchase of investment securities ³	(1,689,087)	(2,388,720)	(2,531,515)
Proceeds from maturity of investment securities ³	1,773,552	2,551,187	2,172,830
Other investing activities net	8,014	(38,157)	(34,050)
Investing activities of discontinued operations			
Sales proceeds	950,010	0	78,908
Other	(55,803)	(154,875)	(124,330)
Net cash required by investing activities	(1,614,354)	(2,328,812)	(2,331,907)
Financing Activities			
Additions to long-term debt	0	0	243,500
Reductions of long-term debt	(340,041)	(332,038)	0
Reductions of nonrecourse debt of a subsidiary	0	(82,000)	(2,572)
Proceeds from exercise of stock options and employee stock purchase plans	15,551	42,995	12,746
Excess tax benefits related to exercise of stock options	4,838	11,672	4,143
Withholding tax on stock-based incentive awards	(8,014)	(5,170)	0
Issue cost of debt facility	(7,905)	0	0
Cash dividends paid	(212,752)	(201,405)	(190,788)
Net cash provided (required) by financing activities	(548,323)	(565,946)	67,029
Effect of exchange rate changes on cash and cash equivalents	(4,660)	881	35,279

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Net increase (decrease) in cash and cash equivalents	(21,952)	234,681	(364,966)
Cash and cash equivalents at January 1	535,825	301,144	666,110
Cash and cash equivalents at December 31	\$ 513,873	535,825	301,144

¹ Reclassified to conform to current presentation.

² Excludes nonrecourse seller financing of \$82 million related to the Company's acquisition of the Hankinson, North Dakota, ethanol plant in 2009.

³ Investments are Canadian government securities with maturities greater than 90 days at the date of acquisition.

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

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Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY**

Years Ended December 31 (<i>Thousands of dollars</i>)	2011	2010	2009
Cumulative Preferred Stock par \$100, authorized 400,000 shares, none issued	0	0	0
Common Stock par \$1.00, authorized 450,000,000 shares at December 31, 2011, 2010 and 2009, issued 193,909,200 shares at December 31, 2011, 193,293,526 shares at December 31, 2010 and 191,797,600 shares at December 31, 2009			
Balance at beginning of year	\$ 193,294	191,798	191,249
Exercise of stock options	615	1,496	549
Balance at end of year	193,909	193,294	191,798
Capital in Excess of Par Value			
Balance at beginning of year	767,762	680,509	631,859
Exercise of stock options, including income tax benefits	21,774	54,887	17,244
Restricted stock transactions and other	(15,119)	(9,688)	2,473
Stock-based compensation	42,492	40,842	27,976
Sale of stock under employee stock purchase plans	1,065	1,212	957
Balance at end of year	817,974	767,762	680,509
Retained Earnings			
Balance at beginning of year	6,800,992	6,204,316	5,557,483
Net income for the year	872,702	798,081	837,621
Cash dividends \$1.10 per share in 2011, \$1.05 per share in 2010 and \$1.00 per share in 2009	(212,752)	(201,405)	(190,788)
Balance at end of year	7,460,942	6,800,992	6,204,316
Accumulated Other Comprehensive Income (Loss)			
Balance at beginning of year	449,428	287,187	(87,697)
Foreign currency translation gains (losses)	(91,247)	165,940	375,951
Retirement and postretirement benefit plan adjustments, net of income taxes	(30,909)	(3,699)	(1,067)
Loss deferred on interest rate hedges, net of income taxes	(16,852)	0	0
Balance at end of year	310,420	449,428	287,187
Treasury Stock			
Balance at beginning of year	(11,926)	(17,784)	(13,949)
Sale of stock under employee stock purchase plans	870	1,295	1,604
Awarded restricted stock, net of forfeitures	6,208	4,305	0
Cancellation of performance-based restricted stock and forfeitures	0	258	(5,439)
Balance at end of year 185,992 shares of Common Stock in 2011, 457,518 shares in 2010 and 682,222 shares in 2009	(4,848)	(11,926)	(17,784)
Total Stockholders' Equity	\$ 8,778,397	8,199,550	7,346,026

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

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note A Significant Accounting Policies

NATURE OF BUSINESS Murphy Oil Corporation is an international oil and gas company that conducts its business through various operating subsidiaries. The Company produces oil and/or natural gas in the United States, Canada, the United Kingdom, Malaysia and Republic of the Congo and conducts oil and natural gas exploration activities worldwide. The Company has an interest in a Canadian synthetic oil operation. Murphy markets petroleum products under various brand names and to unbranded wholesale customers in the United States and United Kingdom. It owns two ethanol production facilities in the United States and one petroleum refinery in the United Kingdom. In 2011, the Company sold two U.S. petroleum refineries and certain associated marketing assets. The Company has announced its intention to sell the U.K. refining and marketing assets.

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

REVENUE RECOGNITION Revenues from sales of crude oil, natural gas and refined petroleum products are recorded when deliveries have occurred and legal ownership of the commodity transfers to the customer. Refined products sold at retail are recorded when the customer takes delivery at the pump. Merchandise revenues are recorded at the point of sale. Revenues from the production of oil and natural gas properties in which Murphy shares an undivided interest with other producers are recognized based on the actual volumes sold by the Company during the period. Gas imbalances occur when the Company's actual sales differ from its entitlement under existing working interests. The Company records a liability for gas imbalances when it has sold more than its working interest of gas production and the estimated remaining reserves make it doubtful that partners can recoup their share of production from the field. At December 31, 2011 and 2010, the liabilities for natural gas balancing were immaterial.

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

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

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

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

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS **Continued**

temporary are recognized currently in earnings. The cost of securities sold is based on the specific identification method. The fair value of investment securities is determined by available market prices. At December 31, 2011, the Company owned Canadian government securities with maturities greater than 90 days at date of acquisition that had a carrying value of \$532,093,000.

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

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

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

The Company records a liability for asset retirement obligations (ARO) equal to the fair value of the estimated cost to retire an asset. The ARO liability is initially recorded in the period in which the obligation meets the definition of a liability, which is generally when a well is drilled or the asset is placed in service. The ARO liability is estimated by the Company's engineers using existing regulatory requirements and anticipated future inflation rates. When the liability is initially recorded, the Company increases the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is increased over time to reflect the change in its present value, and the capitalized cost is depreciated over the useful life of the related long-lived asset. The Company reevaluates the adequacy of its recorded ARO liability at least annually. Actual costs of asset retirements such as dismantling oil and gas production facilities and site restoration are charged against the related liability. Any difference between costs incurred upon settlement of an asset retirement obligation and the recorded liability is recognized as a gain or loss in the Company's earnings.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS **Continued**

Depreciation and depletion of producing oil and gas properties is recorded based on units of production. Unit rates are computed for unamortized exploration drilling and development costs using proved developed reserves; unit rates for unamortized leasehold costs and asset retirement costs are amortized over proved reserves. Proved reserves are estimated by the Company's engineers and are subject to future revisions based on availability of additional information. Refineries, certain marketing facilities and certain common natural gas processing facilities are depreciated primarily using the composite straight-line method with depreciable lives ranging from 14 to 25 years. Gasoline stations and other properties are depreciated over 3 to 20 years by individual unit on the straight-line method. Gains and losses on asset disposals or retirements are included in income as a separate component of revenues.

Turnarounds for major processing units at refineries are scheduled at four to five year intervals. Turnarounds for coking units at Syncrude Canada Ltd. are scheduled at intervals of two to three years. Turnaround work associated with various other less significant units at refineries and Syncrude varies depending on operating requirements and events. Murphy defers turnaround costs incurred and amortizes such costs through Operating Expenses over the period until the next scheduled turnaround. All other maintenance and repairs are expensed as incurred. Renewals and betterments are capitalized. Major turnarounds occurred in 2010 at both the Meraux, Louisiana, and Milford Haven, Wales, refineries.

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

GOODWILL Goodwill is recorded in an acquisition when the purchase price exceeds the fair value of net assets acquired. All recorded goodwill arose from the purchase of an oil and natural gas company by Murphy's wholly owned Canadian subsidiary in 2000. Goodwill is not amortized, but is assessed at least annually for recoverability of the carrying value. The Company assesses goodwill recoverability at each year-end by comparing the fair value of net assets for conventional oil and natural gas properties in Canada with the carrying value of these net assets including goodwill. The fair value of the conventional oil and natural gas reporting unit is determined using the expected present value of future cash flows. The change in the carrying value of goodwill during 2011 was primarily caused by a change in the foreign currency translation rate between years. Based on its assessment of the fair value of its Canadian conventional oil and natural gas operations, the Company believes the recorded value of goodwill is not impaired at December 31, 2011. Should a future assessment indicate that goodwill is not fully recoverable, an impairment charge to write down the carrying value of goodwill would be required. See Note B for accounting changes applicable to goodwill recoverability testing beginning in 2012.

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

INCOME TAXES The Company accounts for income taxes using the asset and liability method. Under this method, income taxes are provided for amounts currently payable and for amounts deferred as tax assets and liabilities based on differences between the financial statement carrying amounts and the tax bases of existing

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS **Continued**

assets and liabilities. Deferred income taxes are measured using the enacted tax rates that are assumed will be in effect when the differences reverse. Petroleum revenue taxes are provided using the estimated effective tax rate over the life of applicable U.K. properties. The accounting rules for income tax uncertainties permit recognition of income tax benefits only when they are more likely than not to be realized. The Company includes potential penalties and interest for uncertain income tax positions in income tax expense.

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

DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES The fair value of a derivative instrument is recognized as an asset or liability in the Company's Consolidated Balance Sheet. Upon entering into a derivative contract, the Company may designate the derivative as either a fair value hedge or a cash flow hedge, or decide that the contract is not a hedge, and thenceforth, recognize changes in the fair value of the contract in earnings. The Company documents the relationship between the derivative instrument designated as a hedge and the hedged items as well as its objective for risk management and strategy for use of the hedging instrument to manage the risk. Derivative instruments designated as fair value or cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. The Company assesses at inception and on an ongoing basis whether a derivative instrument used as a hedge is highly effective in offsetting changes in the fair value or cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting. Changes in the fair value of a qualifying fair value hedge are recorded in earnings along with the gain or loss on the hedged item. Changes in the fair value of a qualifying cash flow hedge are recorded in other comprehensive income until the hedged item is recognized in earnings. When the income effect of the underlying cash flow hedged item is recognized in the Statement of Income, the fair value of the associated cash flow hedge is reclassified from other comprehensive income into earnings. Ineffective portions of a cash flow hedge derivative's change in fair value are recognized currently in earnings. If a derivative instrument no longer qualifies as a cash flow hedge and the underlying forecasted transaction is no longer probable of occurring, hedge accounting is discontinued and the gain or loss recorded in other comprehensive income is recognized immediately in earnings.

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

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

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

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

Note B New Accounting Principles and Recent Accounting Pronouncements

Accounting Principles Adopted

The Company adopted guidance issued by the Financial Accounting Standards Board (FASB) regarding accounting for transfers of financial assets effective January 1, 2010. This guidance makes the concept of a qualifying special-purpose entity as defined previously no longer relevant for accounting purposes. Therefore, formerly qualifying special-purpose entities were reevaluated for consolidation by reporting entities in accordance with the applicable consolidation guidance. This adoption of this guidance did not have a significant effect on the Company's consolidated financial statements.

The Company adopted, effective January 1, 2010, guidance issued by the FASB that requires a company to perform an analysis to determine whether its variable interests give it a controlling financial interest in a variable interest entity. The primary beneficiary of a variable interest entity has both the power to direct the activities of the entity that most significantly impact the entity's economic performance and the obligation to absorb potentially significant losses of the entity or the right to receive potentially significant benefits from the entity. A company is required to make ongoing reassessments of whether it is the primary beneficiary of a variable interest entity. This guidance also amended previous guidance for determining whether an entity is considered a variable interest entity. The adoption of this guidance did not have a significant effect on the Company's consolidated financial statements.

In July 2010, the FASB issued accounting guidance that expanded the disclosure requirements about financing receivables and the related allowance for credit losses. This guidance became effective for the Company at December 31, 2010. Because the Company has no significant financing receivables that extend beyond one year, the impact of this guidance did not have a significant effect on its consolidated financial statement disclosures.

The U.S. Securities and Exchange Commission (SEC) adopted revisions to oil and natural gas reserves reporting requirements which were effective for the Company at year-end 2009. In January 2010, the FASB issued guidance that aligned its oil and gas reserves reporting requirements and effective date with the SEC's guidance. The primary changes to reserves reporting included:

A revised definition of proved reserves, including the use of unweighted average oil and natural gas prices in effect at the beginning of each month during the year to compute such reserves,

Expanding the definition of oil and gas producing activities to include non-traditional and unconventional resources, which includes the Company's Canadian synthetic oil operations at Syncrude,

Allowing companies to voluntarily disclose probable and possible reserves in SEC filings,

Amending required proved reserve disclosures to include separate amounts for synthetic oil and gas,

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Expanded disclosures of proved undeveloped reserves, including discussion of such proved undeveloped reserves five years old or more, and

Disclosure of the qualifications of the chief technical person who oversees the Company's overall reserve process.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

The Company utilized the new SEC and FASB guidance at December 31, 2011, 2010 and 2009 to determine its proved reserves and to develop associated disclosures. The Company chose not to provide voluntary disclosures of probable and possible reserves in this Form 10-K.

Recent Accounting and Reporting Rules

In September 2011, the FASB issued an accounting standards update that simplifies the annual goodwill impairment assessment process by permitting a company to assess whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount before applying the two-step goodwill impairment test. If a company concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the company would be required to conduct the current two-step goodwill impairment test. This change is effective for annual and interim goodwill impairment tests performed in fiscal years beginning in 2012. Early adoption is permitted. The Company does not expect the adoption of this standard in 2012 to have a significant effect on its consolidated financial statements.

In June 2011, the FASB issued an accounting standards update that only permits two options for presentation of Comprehensive Income. Comprehensive Income can be presented in (a) a single continuous Statement of Comprehensive Income, including total comprehensive income, the components of net income, and the components of other comprehensive income, or (b) in two separate but continuous statements for the Statement of Income and the Statement of Comprehensive Income. The new guidance is effective for the Company beginning in the first quarter of 2012. As in prior years, the Company expects to continue to present the Statements of Income and Comprehensive Income in two separate statements, and the adoption of this guidance in 2012 is not expected to have a significant effect on the Company's consolidated financial statements. In December 2011, the FASB deferred the requirement for reclassification adjustments from accumulated other comprehensive income to be measured and presented by line item in the Statements of Income and Comprehensive Income.

Note C Discontinued Operations

In July 2010, the Company announced that it planned to exit the U.S. refining and U.K. refining and marketing businesses. On September 30, 2011, the Company sold the Superior, Wisconsin refinery and related assets for \$214,000,000, plus certain capital expenditures between July 25 and the date of closing and the fair value of all associated hydrocarbon inventories at these locations. On October 1, 2011, the Company sold its Meraux, Louisiana refinery and related assets for \$325,000,000, plus the fair value of associated hydrocarbon inventories. The Company began to account for the results of the Superior, Wisconsin and Meraux, Louisiana refineries and associated marketing assets as discontinued operations beginning in the third quarter 2011. All prior periods presented have been reclassified to conform to this presentation of the Superior and Meraux operating results as discontinued operations. The after-tax gain from disposal of the two refineries netted to \$18,724,000, made up of a gain on the Superior refinery (including associated inventories) of \$77,585,000 and a loss on the Meraux refinery (including associated inventories) of \$58,861,000. The gain on disposal was based on refinery selling prices, plus the sales of all associated inventories at fair value, which was significantly above the last-in, first-out carrying value of the inventories sold. The net gain on sale of the refineries included an after-tax benefit of \$179,152,000 from liquidation of inventories formerly carried mostly under the last-in, first-out cost method. The U.S. refineries sold were formerly reported in the U.S. manufacturing segment. The sale process for the U.K. refining and marketing assets continues.

Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**

The major assets and liabilities related to the Superior and Meraux refineries and associated marketing assets at the time of their sale are presented in the following table.

(Thousands of dollars)

Current assets:		
Accounts receivable		\$ 1,191
Liquid inventories		115,014
Materials and supplies inventories		39,853
Total current assets	U.S. refineries	156,058
Noncurrent assets:		
Property, plant and equipment, net of accumulated depreciation, depletion and amortization		723,980
Other		48,604
Total noncurrent assets	U.S. refineries	772,584
Total assets	U.S. refineries	\$ 928,642
Liabilities:		
Current liabilities		\$ 2,637
Other noncurrent liabilities		14,133
Liabilities associated with assets sold	U.S. refineries	\$ 16,770

On March 12, 2009, the Company sold its operations in Ecuador for net cash proceeds of \$78,900,000. The acquirer also assumed certain tax and other liabilities associated with the Ecuador properties sold. The Ecuador properties sold included 20% interests in producing Block 16 and the nearby Tivacuno area. The Company recorded a gain of \$103,596,000, net of income taxes of \$13,961,000, from the sale of the Ecuador properties in 2009. Ecuador operating results prior to the sale, and the resulting gain on disposal, have been reported as discontinued operations. The major assets and liabilities associated with the Ecuador properties at the time of the sale are presented in the following table.

(Thousands of dollars)

Current assets		\$ 4,214
Property, plant and equipment, net of accumulated depreciation, depletion and amortization		65,178
Other noncurrent assets		683
Assets sold	Ecuador	\$ 70,075
Current liabilities		\$ 105,185
Other noncurrent liabilities		35
Liabilities associated with assets sold	Ecuador	\$ 105,220

Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**

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

(Thousands of dollars)	2011	2010	2009
Revenues:			
U.S. refineries	\$ 3,700,789	3,175,353	2,117,186
Ecuador E&P operations	0	0	125,654
Total revenues	\$ 3,700,789	3,175,353	2,242,840
Income (loss) from operations before income taxes:			
U.S. refineries	\$ 188,231	25,521	41,760
Ecuador E&P operations	0	0	(7,692)
	188,231	25,521	34,068
Gain on sale before income taxes:			
U.S. refineries	12,684	0	0
Ecuador E&P operations	0	0	117,557
	12,684	0	117,557
Total income from discontinued operations before taxes	200,915	25,521	151,625
Provision for income taxes	69,145	6,999	27,858
Income from discontinued operations	\$ 131,770	18,522	123,767

Note D Acquisitions

In August 2010, a wholly-owned subsidiary of the Company purchased an unfinished ethanol production facility in Hereford, Texas, for \$40,000,000. The Company completed construction of the facility and commenced operations near the end of the first quarter of 2011. The Company allocated the purchase price for the Hereford facility based on the fair value of the assets acquired as presented in the following table.

<i>(Thousands of dollars)</i>	
Land and land improvements	\$ 2,379
Buildings and improvements	639
Machinery and transportation equipment	36,982
 Total purchase price Hereford ethanol facility	 \$ 40,000

A wholly-owned subsidiary of the Company purchased an ethanol production facility in Hankinson, North Dakota, on October 1, 2009. The facility has a rated capacity to produce 110 million gallons of ethanol per annum. The \$92,000,000 purchase price was financed with an \$82,000,000 nonrecourse loan held by former owners. The loan bore interest at 5.0% per year and was repayable in 2014. This loan was repaid in full in September 2010. Revenue and expenses associated with the facility have been included in the Company's Consolidated Statement of Income beginning on the date of acquisition. The Company allocated the purchase price for the Hankinson facility based on the fair value of the

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assets acquired as presented in the following table.

(Thousands of dollars)

Inventory		\$ 2,469
Land and land improvements		11,833
Buildings and improvements		9,819
Machinery and transportation equipment		67,879
Total purchase price	Hankinson ethanol facility	\$ 92,000

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Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued****Note E Property, Plant and Equipment**

<i>(Thousands of dollars)</i>	December 31, 2011		December 31, 2010	
	Cost	Net	Cost	Net
Exploration and production ¹	\$ 14,766,637	8,730,124 ²	12,506,579	7,898,417 ²
Refining and marketing	2,456,822	1,688,709	3,794,223	2,409,410
Corporate and other	113,184	56,316	108,041	60,020
	\$ 17,336,643	10,475,149	16,408,843	10,367,847

¹ Includes mineral rights as follows: \$ 1,078,770 619,950 779,036 432,051

² Includes \$21,154 in 2011 and \$17,067 in 2010 related to administrative assets and support equipment.

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

At December 31, 2011, 2010 and 2009, the Company had total capitalized drilling costs pending the determination of proved reserves of \$556,412,000, \$497,765,000 and \$369,862,000, respectively. The following table reflects the net changes in capitalized exploratory well costs during the three-year period ended December 31, 2011.

<i>(Thousands of dollars)</i>	2011	2010	2009
Beginning balance at January 1	\$ 497,765	369,862	310,118
Additions to capitalized exploratory well costs pending the determination of proved reserves	86,035	137,403	119,995
Reclassifications to proved properties based on the determination of proved reserves	0	0	(60,251)
Capitalized exploratory well costs charged to expense or sold	(27,388)	(9,500)	0
Ending balance at December 31	\$ 556,412	497,765	369,862

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

<i>(Thousands of dollars)</i>	2011			2010			2009		
	Amount	No. of Wells	No. of Projects	Amount	No. of Wells	No. of Projects	Amount	No. of Wells	No. of Projects
Aging of capitalized well costs:									
Zero to one year	\$ 69,757	11	5	135,494	15	4	\$ 117,618	10	6
One to two years	143,611	15	3	115,418	10	4	49,628	4	4
Two to three years	101,696	9	2	42,571	3	3	8,870	5	0
Three years or more	241,348	33	6	204,282	31	4	193,746	27	4
	\$ 556,412	68	16	497,765	59	15	\$ 369,862	46	14

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Of the \$486,655,000 of exploratory well costs capitalized more than one year at December 31, 2011, \$306,475,000 is in Malaysia, \$138,634,000 is in the U.S., \$29,188,000 is in Republic of the Congo and \$12,358,000 is in Canada. In Malaysia either further appraisal or development drilling is planned and/or development studies/plans are in various stages of completion. In the U.S. further drilling is anticipated and development plans are being formulated. In Republic of the Congo further appraised drilling is planned. In

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Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**

Canada a continuing drilling and development program is underway. The capitalized well costs charged to expense in 2011 related to exploration costs offshore Republic of the Congo and Brunei. The costs in Republic of the Congo were written off following an impairment charge at the nearby Azurite field, and the Brunei costs were written off based on unsuccessful wells drilled in the area in late 2011.

At year-end 2011, the Company determined that a downward revision of proved oil reserves for the Azurite field, offshore Republic of the Congo, was necessary. The determination was made after an extensive study of the declining well production at the field. It was determined that the remaining reserves, including risked estimated probable and possible reserves, would not allow for recovery of the Company's net investment in the Azurite field. Therefore, an impairment charge of \$368,600,000 was recorded in 2011 to reduce the carrying value of the field to fair value. Fair value was determined using a discounted cash flow model based on certain key assumptions, including future estimated net production levels, future estimated oil prices for the field based on year-end futures prices, and future estimated operating and capital expenditures. The carrying value of the net property, plant and equipment for the Azurite field was reduced at December 31, 2011 to the present value of the net cash inflows for the field based on the results of the discounted cash flow calculation.

In 2010, the Company announced that its Board of Directors had approved plans to exit the U.K. refining and marketing business. These operations are presented as the U.K. refining and marketing segment in Note U. The sale process for the U.K. downstream assets continues. Based on current market conditions, it is possible that the Company could incur a loss if the U.K. downstream assets are sold in a future period. If the sale of the U.K. downstream assets continues to progress, the results of these operations will be presented as discontinued operations in future periods when the criteria for held for sale under U.S. generally accepted accounting principles have been met.

Note F Financing Arrangements

At December 31, 2011, the Company had a \$1.5 billion committed credit facility with a major banking consortium that matures in June 2016. Borrowings under this facility bear interest at prime or varying cost of fund options. Facility fees are due at varying rates on the commitment. At December 31, 2011, the Company had no borrowings under this committed facility. At December 31, 2011, the Company also had no borrowings under uncommitted credit lines that amount to approximately \$400,000,000. If necessary, the Company could borrow funds under all or certain of these uncommitted lines with various financial institutions in future periods. The Company has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities through September 2012.

Note G Long-term Debt

<i>(Thousands of dollars)</i>	December 31	
	2011	2010
Notes payable		
6.375% notes, due 2012, net of unamortized discount of \$38 at December 31, 2011	\$ 349,962	349,846
7.05% notes, due 2029, net of unamortized discount of \$1,616 at December 31, 2011	248,384	248,291
Notes payable to banks, 0.7375% at December 31, 2010	0	340,000
Other, 6%, due through 2028	1,212	1,254
Total debt including current maturities	599,558	939,391
Current maturities	(350,005)	(41)
Total long-term debt	\$ 249,553	939,350

Future amounts repayable under debt agreements are: \$350,005,000 in 2012, \$46,000 in 2013, \$48,000 in 2014, \$51,000 in 2015, \$55,000 in 2016 and \$249,353,000 thereafter.

Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS** Continued

During 2011, the Company used a portion of the proceeds from the sale of two U.S. refineries to repay notes payable outstanding under committed and uncommitted credit facilities.

Note H Asset Retirement Obligations

The majority of the asset retirement obligations liabilities (ARO) recognized by the Company at December 31, 2011 and 2010 related to the estimated costs to dismantle and abandon its producing oil and gas properties and related equipment. A portion of the ARO related to retail gasoline stations. The Company has not recorded an ARO for its refining, ethanol and certain of its marketing assets because sufficient information is presently not available to estimate a range of potential settlement dates for the obligation. These assets are consistently being upgraded and are expected to be operational into the foreseeable future. In these cases, the obligation will be initially recognized in the period in which sufficient information exists to estimate the liability.

A reconciliation of the beginning and ending aggregate carrying amount of the asset retirement obligation for 2011 and 2010 is shown in the following table.

<i>(Thousands of dollars)</i>	2011	2010
Balance at beginning of year	\$ 555,248	476,938
Accretion expense	37,701	31,857
Liabilities incurred	51,858	59,605
Revision of previous estimates	7,608	14,170
Liabilities settled	(32,088)*	(36,506)
Changes due to translation of foreign currencies	(4,782)	9,184
Balance at end of year	\$ 615,545	555,248

* Includes noncash settlements related to sale of assets in Spain in 2011.

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

Note I Income Taxes

The components of income from continuing operations before income taxes for each of the three years ended December 31, 2011 and income tax expense attributable thereto were as follows.

<i>(Thousands of dollars)</i>	2011	2010	2009
Income from continuing operations before income taxes			
United States	\$ 440,753	188,588	261,005
Foreign	1,110,230	1,200,122	974,408
	\$ 1,550,983	1,388,710	1,235,413

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Income tax expense				
Federal	Current	\$ 99,451	110,142	100,276
	Deferred	43,602	(40,981)	2,078
		143,053	69,161	102,354
State		30,372	15,486	7,087
Foreign	Current	497,446	347,746	318,619
	Deferred	139,180	176,758	93,499
		636,626	524,504	412,118
Total		\$ 810,051	609,151	521,559

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Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**

Income tax benefits attributable to employee stock option transactions of \$8,775,000 in 2011, \$15,896,000 in 2010 and \$6,035,000 in 2009 were included in Capital in Excess of Par Value in the Consolidated Balance Sheets.

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

<i>(Thousands of dollars)</i>	2011	2010	2009
Income tax expense based on the U.S. statutory tax rate	\$ 542,844	486,049	432,395
Foreign income subject to foreign taxes at a rate different than the U.S. statutory rate	10,053	56,367	33,395
State income taxes, net of federal benefit	19,742	10,066	4,607
Increase in deferred tax asset valuation allowance related to foreign exploration expenditures	102,714	47,128	34,431
Impairment of Azurite field with no tax benefit	129,010	0	0
Malaysian tax benefits on prior year costs in Block P	(25,573)	0	0
Increase in United Kingdom oil and gas tax rate	14,461	0	0
Other, net	16,800	9,541	16,731
Total	\$ 810,051	609,151	521,559

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2011 and 2010 showing the tax effects of significant temporary differences follows.

<i>(Thousands of dollars)</i>	2011	2010
Deferred tax assets		
Property and leasehold costs	\$ 627,093	391,168
Liabilities for dismantlements	114,175	97,149
Postretirement and other employee benefits	164,044	137,709
Foreign tax credit carryforwards	21,368	47,725
Other deferred tax assets	38,341	47,511
Total gross deferred tax assets	965,021	721,262
Less valuation allowance	(445,842)	(305,349)
Net deferred tax assets	519,179	415,913
Deferred tax liabilities		
Property, plant and equipment	(851,330)	(729,699)
Accumulated depreciation, depletion and amortization	(754,295)	(702,512)
Deferred major repair costs	(11,257)	(35,848)
Other deferred tax liabilities	(67,494)	(96,838)
Total gross deferred tax liabilities	(1,684,376)	(1,564,897)
Net deferred tax liabilities	\$ (1,165,197)	(1,148,984)

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In management's judgment, the net deferred tax assets in the preceding table will more likely than not be realized as reductions of future taxable income or by utilizing available tax planning strategies. The valuation allowance for deferred tax assets relates primarily to tax assets arising in foreign tax jurisdictions and foreign tax credit carryforwards. In the judgment of management at the present time, these tax assets are not likely to be realized. The foreign tax credit carryforwards expire in 2014 through 2020. The valuation allowance increased

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS **Continued**

\$140,493,000 in 2011, with these changes primarily offsetting the change in certain deferred tax assets. Any subsequent reductions of the valuation allowance will be reported as reductions of tax expense assuming no offsetting change in the deferred tax asset.

The Company has not recognized a deferred tax liability for undistributed earnings of its Canadian and certain other foreign subsidiaries because such earnings are considered indefinitely invested in foreign countries. As of December 31, 2011, undistributed earnings of the Company's subsidiaries considered indefinitely invested were approximately \$4,895,000,000. The unrecognized deferred tax liability is dependent on many factors including withholding taxes under current tax treaties and foreign tax credits and is estimated to be \$492,469,000. The Company does not consider undistributed earnings from certain other international operations to be indefinitely invested; however, any estimated tax liabilities upon repatriation of earnings from these international operations are expected to be offset with foreign tax credits. Although the Company does not foresee repatriating earnings considered indefinitely invested, under present law, it would incur a 5% withholding tax on any monies repatriated from Canada to the United States.

Uncertain Income Tax Positions

The FASB's rules for accounting for income tax uncertainties clarify the criteria for recognizing uncertain income tax benefits and require additional disclosures about uncertain tax positions. Under current rules the financial statement recognition of the benefit for a tax position is dependent upon the benefit being more likely than not to be sustainable upon audit by the applicable taxing authority. If this threshold is met, the tax benefit is then measured and recognized at the largest amount that is greater than 50 percent likely of being realized upon ultimate settlement. Liabilities associated with uncertain income tax positions are included in Deferred Credits and Other Liabilities in the Consolidated Balance Sheet. A reconciliation of the beginning and ending amount of the consolidated liability for unrecognized income tax benefits during the years ended December 31, 2011 and 2010 follows.

<i>(Thousands of dollars)</i>	2011	2010
Balance at January 1	\$ 23,196	25,978
Additions for tax positions related to current year	1,294	1,225
Settlements due to lapse of time	(5,633)	(4,007)
Balance at December 31	\$ 18,857	23,196

All additions or reductions to the above liability affect the Company's effective income tax rate in the respective period of change. The Company accounts for any applicable interest and penalties on uncertain tax positions as a component of income tax expense. The Company also had other recorded liabilities as of December 31, 2011 and 2010 for interest and penalties of \$976,000 and \$1,010,000, respectively, associated with uncertain tax positions. Income tax expense for the years ended December 31, 2011, 2010 and 2009 included (charges)/benefits for interest and penalties of \$34,000, \$(43,000) and \$1,763,000, respectively, associated with uncertain tax positions.

During the next twelve months, the Company currently expects to add between \$1,000,000 and \$2,000,000 to the liability for uncertain taxes for 2012 events. Although existing liabilities could be reduced by settlement with taxing authorities or lapse due to statute of limitations, the Company believes that the changes in its unrecognized tax benefits due to these events will not have a material impact on the Consolidated Statement of Income during 2012.

The Company's tax returns in multiple jurisdictions are subject to audit by taxing authorities. These audits often take years to complete and settle. Although the Company believes that recorded liabilities for unsettled issues are

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adequate, additional gains or losses could occur in future years from resolution of outstanding unsettled matters. As of December 31, 2011, the earliest years remaining open for audit and/or settlement in our major taxing jurisdictions are as follows: United States 2008; Canada 2007; United Kingdom 2010; and Malaysia 2006.

Note J Incentive Plans

Costs resulting from all share-based payment transactions are recognized as an expense in the financial statements using a fair value-based measurement method over the periods that the awards vest.

The 2007 Annual Incentive Plan (2007 Annual Plan) authorizes the Executive Compensation Committee (the Committee) to establish specific performance goals associated with annual cash awards that may be earned by officers, executives and certain other employees. Cash awards under the 2007 Annual Plan are determined based on the Company's actual financial and operating results as measured against the performance goals established by the Committee. The 2007 Long-Term Incentive Plan (2007 Long-Term Plan) authorizes the Committee to make grants of the Company's Common Stock to employees. These grants may be in the form of stock options (nonqualified or incentive), stock appreciation rights (SAR), restricted stock, restricted stock units, performance units, performance shares, dividend equivalents and other stock-based incentives. The 2007 Long-Term Plan expires in 2017. A total of 6,700,000 shares are issuable during the life of the 2007 Long-Term Plan, with annual grants limited to 1% of Common shares outstanding; allowed shares not granted may be granted in future years. At December 31, 2011, approximately 5,745,000 shares remained available for issuance under the 2007 Long-Term Plan. The Company also has a Stock Plan for Non-Employee Directors (Directors Plan) that permits the issuance of restricted stock, restricted stock units and stock options or a combination thereof to the Company's Non-Employee Directors.

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

Amounts recognized in the financial statements with respect to share-based plans are as follows.

<i>(Thousands of dollars)</i>	2011	2010	2009
Compensation charged against income before income tax benefit	\$ 43,272	41,992	28,618
Related income tax benefit recognized in income	13,053	12,169	7,860

As of December 31, 2011, there was \$55,100,000 in compensation costs to be expensed over approximately the next two years related to unvested share-based compensation arrangements granted by the Company. Cash received from options exercised under all share-based payment arrangements for the years ended December 31, 2011, 2010 and 2009 was \$15,551,000, \$42,995,000 and \$12,746,000, respectively. Total income tax benefits realized from tax deductions related to stock option exercises under share-based payment arrangements were \$8,775,000, \$15,896,000 and \$6,035,000 for the years ended December 31, 2011, 2010 and 2009, respectively.

STOCK OPTIONS The Committee fixes the option price of each option granted at no less than fair market value (FMV) on the date of the grant and fixes the option term at no more than seven years from such date. Each option granted to date under the 2007 Long-Term Plan has been unqualified, with a term of seven years and an option price equal to FMV at date of grant. Under the 2007 Long-Term Plan, one-half of each grant is exercisable after two years and the remainder after three years. Under the Directors Plan, one-third of each grant is exercisable after each of the first three years.

The fair value of each option award is estimated on the date of grant using the Black-Scholes pricing model using the assumptions noted in the following table. Expected volatility is based on historical volatility of the

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Company's stock and implied volatility on publicly traded at-the-money options on the Company's stock. The Company estimates the expected term of the options granted based on historical option exercise patterns and considers certain groups of employees exhibiting different behavior. The risk-free rate for periods within the expected term of the option is based on the U.S. Treasury yield curve in effect at the time of grant.

	2011	2010	2009
Fair value per option grant	\$ 20.34	18.75	\$ 15.15
Assumptions			
Dividend yield	1.80%	1.80%	1.40%
Expected volatility	37.00%	43.00%	41.00%
Risk-free interest rate	2.10%	2.52%	1.95%
Expected life	5.10 yrs.	5.25 yrs.	5.25 yrs.

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

	Number of Shares	Average Exercise Price
Outstanding at December 31, 2008	5,399,060	\$ 40.90
Granted at FMV	1,057,000	43.95
Exercised	(560,500)	19.58
Forfeited	(464,000)	60.65
Outstanding at December 31, 2009	5,431,560	42.01
Granted at FMV	1,605,628	52.85
Exercised	(1,580,950)	29.04
Forfeited	(153,854)	53.33
Outstanding at December 31, 2010	5,302,384	48.83
Granted at FMV	1,397,312	67.64
Exercised	(974,500)	39.30
Forfeited	(290,968)	52.73
Outstanding at December 31, 2011	5,434,228	55.17
Exercisable at December 31, 2009	3,506,310	\$ 34.86
Exercisable at December 31, 2010	2,499,610	45.07
Exercisable at December 31, 2011	2,319,735	51.14

Additional information about stock options outstanding at December 31, 2011 is shown below.

Range of Exercise Prices per Option	Options Outstanding			Options Exercisable		
	No. of Options	Avg. Life in Years	Aggregate Intrinsic Value	No. of Options	Avg. Life in Years	Aggregate Intrinsic Value
\$19.43 to \$23.58	393,750	1.0	\$ 13,571,000	393,750	1.0	\$ 13,571,000

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\$30.30 to \$45.23	953,610	3.6	11,466,000	541,235	3.2	6,604,000
\$51.07 to \$57.32	2,067,156	3.9	5,938,000	730,750	1.7	2,069,000
\$67.64 to \$72.75	2,019,712	5.1	0	654,000	3.1	0
	5,434,228	4.1	\$ 30,975,000	2,319,735	2.3	\$ 22,244,000

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Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**

The total intrinsic value of options exercised during 2011, 2010 and 2009 was \$28,145,000, \$49,929,000 and \$17,932,000, respectively. Intrinsic value is the excess of the market price of stock at date of exercise over the exercise price received by the Company upon exercise. Aggregate intrinsic value is nil when the exercise price of the stock option exceeds the market price of the Company's Common stock.

SAR SAR may be granted in conjunction with or independent of stock options; if granted, the Committee would determine when SAR may be exercised and the price. No SAR have been granted.

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

<i>(Number of shares or share units)</i>	2011	2010	2009
Balance at beginning of year	1,023,492	872,027	806,822
Granted	521,423	449,100	375,050
Awarded	(309,656)	(252,551)	0
Forfeited	(60,767)	(45,084)	(309,845)
Balance at end of year	1,174,492	1,023,492	872,027

The fair value of the performance-based awards granted in each year was estimated on the date of grant using a Monte Carlo valuation model. Expected volatility was based on daily historical volatility of the Company's stock price compared to a peer group average over a three-year period. The risk-free interest rate is based on the yield curve of three-year U.S. Treasury bonds and the stock beta was calculated using three years of historical averages of daily stock data for Murphy and the peer group. The assumptions used in the valuation of the performance awards granted in 2011, 2010 and 2009 are presented in the following table.

	2011	2010	2009
Fair value per share at grant date	\$38.94 \$64.89	\$42.38 \$50.95	\$41.18 \$44.94
Assumptions			
Expected volatility	51.00%	51.00%	48.00%
Risk-free interest rate	1.04%	1.41%	1.37%
Stock beta	1.006	1.008	0.973
Expected life	3.00 yrs.	3.00 yrs.	3.00 yrs.

TIME-LAPSE RESTRICTED STOCK AND RESTRICTED STOCK UNITS Restricted stock and restricted stock units (RSU) have been granted to the Company's Non-Employee Directors under the Directors Plan. These awards vest on the third anniversary of the date of grant. The fair value of these awards was estimated based on the fair market value of the Company's stock on the date of grant, which was \$52.66 in 2011, \$52.49 per share in

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2010 and \$43.95 per share in 2009. Changes in time-lapse restricted stock and restricted stock units outstanding for each of the last three years are presented in the following table.

<i>(Number of shares or share units)</i>	2011	2010	2009
Balance at beginning of year	166,173	164,695	132,819
Granted	32,711	43,370	50,290
Expired	(82,160)	(29,475)	(18,414)
Forfeited	0	(12,417)	0
Balance at end of year	116,724	166,173	164,695

PERFORMANCE UNITS The Company also awarded performance units in 2011 to certain U.S. retail marketing employees under the 2007 Long-Term Plan. The performance units are to be paid in cash and awards are computed at between 0% and 200% of targeted amounts based on achievement of U.S. retail financial performance over the three-year term of the award. Total expense related to these awards was \$871,000 in 2011.

EMPLOYEE STOCK PURCHASE PLAN (ESPP) The Company has an ESPP under which the Company's Common Stock can be purchased by eligible U.S. and Canadian employees. Each quarter, an eligible employee may elect to withhold up to 10% of his or her salary to purchase shares of the Company's stock at the end of the quarter at a price equal to 90% of the fair value of the stock as of the first day of the quarter. The ESPP will terminate on the earlier of the date that employees have purchased all 980,000 authorized shares or June 30, 2017. Employee stock purchases under the ESPP were 34,612 shares at an average price of \$56.08 per share in 2011, 44,361 shares at \$51.97 per share in 2010, and 51,271 shares at \$44.73 per share in 2009. At December 31, 2011, 321,322 shares remained available for sale under the ESPP. Compensation costs related to the ESPP are estimated based on the value of the 10% discount and the fair value of the option that provides for the refund of participant withholdings, and such expenses were \$328,000 in 2011, \$357,000 in 2010 and \$623,000 in 2009. The fair value per share issued under the ESPP was approximately \$8.60, \$7.51 and \$11.47 for the years ended December 31, 2011, 2010 and 2009, respectively.

SAVINGS-RELATED SHARE OPTION PLAN (SOP) One of the Company's U.K. subsidiaries has provided a plan that allows shares of the Company's Common stock to be purchased by eligible employees using payroll withholdings. An eligible employee may elect to withhold from £5 to £250 per month to purchase shares of Company stock at a price equal to 90% of the fair value of the stock as of the date of grant. The SOP plan has a term of three years and employee withholdings are fixed over the life of the plan. At the end of the term of the SOP plan an employee receives interest on withholdings and has six months to either use all or part of the withholdings plus credited interest to purchase shares of Company stock or receive a repayment of withholdings plus credited interest. The SOP is expected to expire in 2012. Compensation costs related to the SOP plan are estimated based on the value of the 10% discount and the fair value of the option that allows the employee to receive a repayment of withholdings plus credited interest. The fair value per share of the SOP plans with holding periods ending in December 2009, August 2010, April 2011 and May 2012 were \$19.57, \$19.90, \$23.77 and \$22.85, respectively.

CASH AWARDS The Committee also administers the Company's incentive compensation plans, which provide for annual or periodic cash awards to officers, directors and certain other employees. These cash awards are generally determinable based on the Company achieving specific financial and/or operational objectives. Compensation expense of \$33,035,000, \$25,171,000 and \$23,073,000 was recorded in 2011, 2010 and 2009, respectively, for these plans.

Note K Employee and Retiree Benefit Plans

PENSION AND OTHER POSTRETIREMENT PLANS The Company has defined benefit pension plans that are principally noncontributory and cover most full-time employees. All pension plans are funded except for the

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U.S. and Canadian nonqualified supplemental plans and the U.S. directors' plan. All U.S. tax qualified plans meet the funding requirements of federal laws and regulations. Contributions to foreign plans are based on local laws and tax regulations. The Company also sponsors health care and life insurance benefit plans, which are not funded, that cover most retired U.S. employees. The health care benefits are contributory; the life insurance benefits are noncontributory.

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

The tables that follow provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets for the years ended December 31, 2011 and 2010 and a statement of the funded status as of December 31, 2011 and 2010.

<i>(Thousands of dollars)</i>	Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010
Change in benefit obligation				
Obligation at January 1	\$ 575,300	521,471	122,879	101,750
Service cost	22,406	20,706	4,547	4,133
Interest cost	30,785	30,144	6,141	6,211
Plan amendments	483	0	0	0
Participant contributions	35	33	1,049	956
Actuarial loss	66,010	30,544	4,791	14,646
Medicare Part D subsidy	0	0	555	528
Exchange rate changes	(2,109)	(1,357)	(11)	22
Benefits paid	(27,745)	(26,241)	(5,667)	(5,367)
Reduction due to sale of the Superior refinery	(23,021)	0	0	0
Special termination benefits	695	0	0	0
Curtailments	(13,271)	0	(19,322)	0
Obligation at December 31	629,568	575,300	114,962	122,879
Change in plan assets				
Fair value of plan assets at January 1	416,272	375,947	0	0
Actual return on plan assets	(1,415)	46,792	0	0
Employer contributions	38,357	20,651	4,063	3,883
Participant contributions	35	33	1,049	956
Medicare Part D subsidy	0	0	555	528
Exchange rate changes	(1,786)	(422)	0	0
Benefits paid	(27,745)	(26,241)	(5,667)	(5,367)
Distribution to acquirer of the Superior refinery	(18,720)	0	0	0
Other	(648)	(488)	0	0
Fair value of plan assets at December 31	404,350	416,272	0	0

Funded status and amounts recognized in the Consolidated Balance Sheets at December 31

Deferred charges and other assets	10,621	14,191	0	0
Other accrued liabilities	(3,488)	(3,378)	(5,022)	(5,223)
Deferred credits and other liabilities	(232,351)	(169,841)	(109,940)	(117,656)
Funded status and net plan liability recognized at December 31	\$(225,218)	(159,028)	(114,962)	(122,879)

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The Company sold the Meraux, Louisiana and Superior, Wisconsin refineries in 2011. These sales reduced the pension benefit obligation due to a curtailment whereby no additional future benefits will be earned by the employees at the refineries after the sales. Additionally, the acquirer of the Superior refinery assumed the retirement plan covering the union employees. Therefore during 2011, the pension benefit obligation was reduced and certain applicable retirement plan assets were distributed to the acquirer related to the plan liabilities assumed by the acquirer.

At December 31, 2011, amounts included in accumulated other comprehensive income (AOCI), before reduction for associated deferred income taxes, which have not been recognized in net periodic benefit expense are shown in the following table.

<i>(Thousands of dollars)</i>	Pension Benefits	Other Postretirement Benefits
Net actuarial loss	\$ (216,276)	(35,336)
Prior service (cost) credit	(5,262)	1,130
Transitional asset (liability)	1,609	(17)
	\$ (219,929)	(34,223)

Amounts included in AOCI at December 31, 2011 that are expected to be amortized into net periodic benefit expense during 2012 are shown in the following table.

<i>(Thousands of dollars)</i>	Pension Benefits	Other Postretirement Benefits
Net actuarial loss	\$ (16,872)	(1,846)
Prior service (cost) credit	(1,258)	173
Transitional asset (liability)	535	(8)
	\$ (17,595)	(1,681)

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

<i>(Thousands of dollars)</i>	Projected Benefit Obligations		Accumulated Benefit Obligations		Fair Value of Plan Assets	
	2011	2010	2011	2010	2011	2010
Funded qualified plans where accumulated benefit obligation exceeds fair value of plan assets	\$ 513,444	478,234	459,556	431,668	374,360	383,683
Unfunded nonqualified and directors' plans where accumulated benefit obligation exceeds fair value of plan assets	96,754	78,667	82,642	69,104	0	0
Unfunded other postretirement plans	114,962	122,879	114,962	122,879	0	0

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The table that follows provides the components of net periodic benefit expense for each of the three years ended December 31, 2011.

<i>(Thousands of dollars)</i>	2011	Pension Benefits			Other Postretirement Benefits		
		2011	2010	2009	2011	2010	2009
Service cost	\$ 22,406	20,706	17,052	4,547	4,133	3,121	
Interest cost	30,785	30,144	28,767	6,141	6,211	5,688	
Expected return on plan assets	(25,919)	(24,199)	(20,375)	0	0	0	
Amortization of prior service cost	1,314	1,558	1,635	(240)	(263)	(263)	
Amortization of transitional asset (liability)	(536)	(514)	(466)	8	8	0	
Recognized actuarial loss	12,484	12,257	10,305	2,329	2,790	1,551	
	40,534	39,952	36,918	12,785	12,879	10,097	
Termination benefits expense	695	0	1,867	0	0	0	
Curtailement expense	1,036	0	575	(605)	0	397	
Net periodic benefit expense	\$ 42,265	39,952	39,360	12,180	12,879	10,494	

The increase in net periodic benefit expense in 2011 compared to prior years was primarily attributable to additional employees covered by retirement plans for most of 2011, plus termination and curtailment expenses related to sale of two U.S. petroleum refineries in 2011.

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

<i>(Thousands of dollars)</i>	2011	Pension Benefits		Other Postretirement Benefits	
		2011	2010	2011	2010
Benefit obligation at December 31	\$ 153,947	133,751	454	430	
Fair value of plan assets at December 31	135,608	126,075	0	0	
Net plan liabilities recognized	18,339	7,676	454	430	
Net periodic benefit expense	8,978	9,784	82	60	

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2011 and 2010 and net periodic benefit expense for 2011 and 2010.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	December 31	December 31	December 31	December 31	Year	Year	Year	Year
Discount rate	2011	2010	2011	2010	2011	2010	2011	2010
	5.00%	5.66%	4.87%	5.66%	5.50%	5.88%	5.50%	5.90%
Expected return on plan assets	6.48%	6.56%	0%	0%	6.48%	6.56%	0%	0%
Rate of compensation increase	4.22%	4.19%	0%	0%	4.22%	4.19%	0%	0%

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The discount rates used for purposes of determining the plan obligations and expense are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate which is the basis for selecting the discount

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rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Expected compensation increases are based on anticipated future averages for the Company.

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

<i>(Thousands of dollars)</i>	Pension Benefits	Other Postretirement Benefits
2012	\$ 28,688	5,835
2013	29,911	6,072
2014	31,237	6,262
2015	32,001	6,449
2016	32,738	6,747
2017-2021	185,062	38,516

For purposes of measuring postretirement benefit obligations at December 31, 2011, the future annual rates of increase in the cost of health care were assumed to be 7.8% for 2012 decreasing each year to an ultimate rate of 5.0% in 2020 and thereafter.

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

<i>(Thousands of dollars)</i>	1% Increase	1% Decrease
Effect on total service and interest cost components of net periodic postretirement benefit expense for the year ended December 31, 2011	\$ 2,033	(1,594)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 2011	17,041	(13,810)

U.S. Health Care Reform In March 2010, the United States Congress enacted a health care reform law. Along with other provisions, the law (a) eliminates the tax free status of federal subsidies to companies with qualified retiree prescription drug plans that are actuarially equivalent to Medicare Part D plans beginning in 2013; (b) imposes a 40% excise tax on high-cost health plans as defined in the law beginning in 2018; (c) eliminates lifetime or annual coverage limits and required coverage for preventative health services beginning in September 2010; and (d) imposed a fee of \$2 (subsequently adjusted for inflation) for each person covered by a health insurance policy beginning in September 2010.

The Company provides a health care benefit plan to eligible U.S. employees and most U.S. retired employees. The new law did not significantly affect the Company's consolidated financial statements as of December 31, 2011 and 2010 and for the years then ended. The Company continues to evaluate the various components of the law as guidance is issued and cannot predict with certainty all the ways it may impact the Company. However, based on the evaluation performed to date, the Company currently believes that the health care reform law will not have a material effect on its financial condition, net income or cash flow in future periods.

Plan Investments Murphy Oil Corporation maintains an Investment Policy Statement (Statement) that establishes investment standards related to its two funded domestic qualified retirement plans. The Statement specifies that all assets will be held in a Master Trust sponsored by the Company, which is administrated by a trustee appointed by the Investment Committee (Committee). Members of the Committee are appointed by the Board of Directors. The Committee hires Investment Managers to invest trust assets within the guidelines established by the Committee as allowed by the Statement. The investment goals call for a portfolio of assets consisting of equity, fixed income and cash equivalent securities. The primary consideration for investments is

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the preservation of capital, and investment growth should exceed the rate of inflation. The Committee has directed the asset investment advisors of its benefit plans to maintain a portfolio consisting of both equity and fixed income securities. The Company believes that over time a balanced to slightly heavier weighting of the portfolio in equity securities compared to fixed income securities represents the most appropriate long-term mix for future investment return on assets held by domestic plans. The parameters for asset allocation call for the following minimum and maximum percentages: equity securities of between 40% and 70%; fixed income securities of between 30% and 60%; long/short equity of between 0% and 15%; and cash and equivalents of between 0% and 15%. The Committee is authorized to direct investments within these parameters. Equity investments may include common, preferred and convertible preferred stocks, emerging markets stocks and similar funds, and long/short equity funds. Long/short equity is a strategy invested in a portfolio of long stocks hedged with short sales of stocks and/or stock index options, with the combination of investment intended to produce equity-like returns with lower volatility over the long term. Generally no more than 10% of an Investment Manager's portfolio is to be held in equity securities of any one issuer, and equity securities should have a minimum market capitalization of \$100 million. Equities held in the trust should be listed on the New York or American Stock Exchanges, principal U.S. regional exchanges, major foreign exchanges or quoted in significant over-the-counter markets. Equity or fixed income securities issued by the Company may not be held in the trust. Fixed income securities include maturities greater than one year to maturity. The fixed income portfolio should not exceed an average maturity of 11 years. The portfolio may include investment grade corporate bonds, issues of the U.S. government, its agencies and government sponsored entities, government agency issued collateralized mortgage backed securities, agency issued mortgage backed securities, municipal bonds, asset backed securities, commercial mortgage backed securities and international and emerging markets bond funds. The Committee routinely reviews the investment performance of Investment Managers.

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

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

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The weighted average asset allocation for the Company's funded pension benefit plans at December 31, 2011 and 2010 are presented in the following table.

	December 31,	
	2011	2010.
Equity securities	62.3%	62.7%
Fixed income securities	36.5	36.2
Cash equivalents	1.2	1.1
	100.0%	100.0%

The Company's weighted average expected return on plan assets was 6.48% in 2011 and the return was determined based on an assessment of actual long-term historical returns and expected future returns for a portfolio with investment characteristics similar to that maintained by the plans. The 6.48% expected return was based on an expected average future equity securities return of 8.29% and a fixed income securities return of 4.53% and is net of average expected investment expenses of 0.28%. Over the last 10 years, the return on funded retirement plan assets has averaged 5.06%.

At December 31, 2011 and 2010, the fair value measurements of retirement plan assets within the fair value hierarchy were as follows:

	Fair Value at December 31, 2011	Fair Value Measurements Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
<i>(Thousands of dollars)</i>				
Domestic Plans				
Equity securities:				
U.S. core equity	\$ 73,986	73,986	0	0
U.S. small/midcap	18,236	18,236	0	0
U.S. long/short equity fund	13,860	0	13,860	0
International commingled trust fund	56,156	0	56,156	0
Emerging market commingled equity fund	6,980	0	6,980	0
Fixed income securities:				
U.S. fixed income	76,764	0	76,764	0
International commingled trust fund	13,109	0	13,109	0
Emerging market mutual fund	6,448	0	6,448	0
Cash and equivalents	3,203	3,203	0	0
Total Domestic Plans	268,742	95,425	173,317	0
Foreign Plans				
Equity securities funds	59,349	0	59,349	0
Fixed income securities funds	44,442	0	44,442	0
Diversified pooled fund	29,990	0	29,990	0
Cash and equivalents	1,827	1,827	0	0

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Total Foreign Plans	135,608	1,827	133,781	0
Total	\$ 404,350	97,252	307,098	0

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	Fair Value at December 31, 2010	Fair Value Measurements Using		
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
<i>(Thousands of dollars)</i>				
Domestic Plans				
Equity securities:				
U.S. core equity	\$ 79,550	79,550	0	0
U.S. small/midcap	17,324	17,324	0	0
U.S. long/short equity fund	14,205	0	14,205	0
International commingled trust fund	61,531	0	61,531	0
Emerging market commingled equity fund	7,131	0	7,131	0
Fixed income securities:				
U.S. fixed income	81,989	0	81,989	0
International commingled trust fund	19,833	0	19,833	0
Emerging market mutual fund	7,045	0	7,045	0
Cash and equivalents	1,589	1,589	0	0
Total Domestic Plans	290,197	98,463	191,734	0
Foreign Plans				
Equity securities funds	58,353	0	58,353	0
Fixed income securities funds	31,948	0	31,948	0
Diversified pooled fund	32,590	0	32,590	0
Cash and equivalents	3,184	3,184	0	0
Total Foreign Plans	126,075	3,184	122,891	0
Total	\$ 416,272	101,647	314,625	0

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

For domestic plans, U.S. core and small/midcap equity securities are valued based on daily market prices as quoted on national stock exchanges or in the over-the-counter market. U.S. long/short equity securities are valued monthly based on a pro-rata share of value. International equities held in a commingled trust are valued monthly based on prices as quoted on various international stock exchanges. The emerging market commingled equity fund is valued monthly based on net asset value. U.S. fixed income securities are valued daily based on bids for the same or similar securities or using net asset values. International fixed income securities held in a commingled trust are valued on a monthly basis using net asset values. The fixed income emerging market mutual fund is valued daily based on net asset value. The domestic plan commingled trusts have waiting periods for withdrawals ranging from 6 to 30 days, while U.S. long/short equity funds permit withdrawals annually for the first year and then semi-annually thereafter. For foreign plans, the equity securities funds are comprised of U.K. and foreign equity funds valued daily based on fund net asset values. Fixed income securities funds are U.K. securities valued daily at net asset values. The diversified pooled fund is valued daily at net asset value and contains a combination of Canadian and foreign equity securities, Canadian fixed income securities and cash.

During 2011, the Company made contributions of \$23,736,000 to its domestic defined benefit pension plans, \$14,621,000 to its foreign defined benefit pension plans, \$4,011,000 to its domestic postretirement benefits plan and \$52,000 to its foreign postretirement benefits plan. The Company currently expects during 2012 to make contributions of \$27,171,000 to its domestic defined benefit pension plans, \$8,311,000 to its

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foreign defined benefit pension plans, \$5,790,000 to its domestic postretirement benefits plan and \$45,000 to its foreign postretirement benefits plan.

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Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS** Continued

THRIFT PLANS Most full-time employees of the Company may participate in thrift or savings plans by allotting up to a specified percentage of their base pay. The Company matches contributions at a stated percentage of each employee's allotment based on years of participation in the plans. A U.K. savings plan allows eligible employees to allot a portion of their base pay to purchase Company Common Stock at market value. Such employee allotments are matched by the Company. Amounts charged to expense for these U.S. and U.K. plans were \$10,725,000 in 2011, \$11,467,000 in 2010 and \$11,617,000 in 2009.

Note L Financial Instruments and Risk Management

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

Commodity Purchase Price Risks The Company is subject to commodity price risks at its ethanol production facilities in the United States related to corn that it will purchase in the future for feedstock and to wet and dried distillers grain that it will sell in the future. At December 31, 2011 and 2010, the Company had open physical delivery fixed-price commitment contracts for purchase of approximately 8.0 million and 7.0 million bushels of corn, respectively, for processing at its ethanol plants. The Company also had outstanding derivative contracts to sell a similar volume of these fixed-price quantities and buy them back at future prices in effect on the expected date of delivery under the purchase commitment contracts. Also, at December 31, 2011, the Company had open physical delivery fixed-price commitment contracts to sell approximately 1.1 million equivalent bushels of wet and dried distillers grain with solubles; it also had outstanding derivative contracts to purchase a similar volume of these fixed-price quantities and sell them back at future prices in effect on the expected date of delivery under the sale commitment contracts. Additionally, at December 31, 2011, the Company had outstanding derivative contracts to sell 2.9 million bushels of corn and buy them back when certain corn inventories are expected to be processed at the Hankinson, North Dakota, and Hereford, Texas facilities. The fair value of these open commodity derivative contracts was a liability of \$292,000 at December 31, 2011 and an asset of \$750,000 at December 31, 2010.

The Company was formerly subject to commodity price risk related to crude oil feedstocks it held in inventory at its U.S. refineries. Short-term derivative instruments were outstanding at December 31, 2010 to manage the 2011 purchase price of 118,000 barrels of crude oil at the Company's Superior, Wisconsin refinery. The fair value of these open crude oil derivative contracts was a liability of \$335,000 at December 31, 2010. The Superior refinery was sold in 2011 and has been accounted for as discontinued operations. There were no open crude oil feedstock derivative contracts at December 31, 2011.

Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS** Continued

Foreign Currency Exchange Risks The Company is subject to foreign currency exchange risk associated with operations in countries outside the U.S. At December 31, 2011 and 2010, short-term derivative instruments were outstanding to manage the currency risk of approximately \$16,000,000 and \$38,000,000, respectively, of U.S. dollar accounts receivable balances associated with the Company's sale of Canadian crude oil. Also short-term derivative instruments were outstanding at December 31, 2011 and 2010 to manage the currency risk of approximately \$472,000,000 and \$366,000,000 equivalent, respectively, of ringgit denominated income tax liability balances in the Company's Malaysian operations. The fair value of open foreign currency derivative contracts was a liability of \$8,459,000 at December 31, 2011 and an asset of \$7,261,000 at December 31, 2010.

At December 31, 2011 and 2010, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

(Thousands of dollars)	December 31, 2011				December 31, 2010			
	Asset Derivatives		Liability Derivatives		Asset Derivatives		Liability Derivatives	
	Balance		Balance		Balance		Balance	
	Sheet Location	Fair Value	Sheet Location	Fair Value	Sheet Location	Fair Value	Sheet Location	Fair Value
Type of								
<u>derivative contract</u>								
Commodity	Accounts Receivable	\$197	Accounts Payable	\$489	Accounts Receivable	\$750	Accounts Payable	\$626
Foreign exchange			Accounts Payable	\$8,459	Accounts Receivable	\$7,261		

For the years ended December 31, 2011 and 2010, the gains and losses recognized in the Consolidated Statements of Income for derivative instruments not designated as hedging instruments are presented in the following table.

(Thousands of dollars)	Year Ended December 31, 2011		Year Ended December 31, 2010	
	Location of	Amount of	Location of	Amount of
	Gain (Loss)	Gain (Loss)	Gain (Loss)	Gain (Loss)
	Recognized in Income on Derivative	Recognized in Income on Derivative	Recognized in Income on Derivative	Recognized in Income on Derivative
Type of				
<u>derivative contract</u>				
Commodity	Crude Oil and Product Purchases	\$ 5,659	Crude Oil and Product Purchases	\$ (7,577)
Foreign exchange	Interest and Other Income (Loss)	(305)	Interest and Other Income (Loss)	34,215
		\$ 5,354		\$ 26,638

Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**

Interest Rate Risks The Company has ten-year notes totaling \$350,000,000 that mature on May 1, 2012. The Company currently anticipates replacing these notes at maturity with new ten-year notes, and it therefore has risk associated with the interest rate related to the anticipated sale of these notes in 2012. To manage this risk, in 2011 the Company entered into a series of derivative contracts known as forward starting interest rate swaps that mature in May 2012. The Company utilizes hedge accounting to defer any gain or loss on these contracts until the payment of interest on these anticipated notes occurs. There was no impact in the 2011 Consolidated Statements of Income associated with accounting for these interest rate derivative contracts.

At December 31, 2011, the fair value of these interest rate derivative contracts, which have been designated as hedging instruments for accounting purposes, are presented in the following table.

<i>(Thousands of dollars)</i> <u>Type of derivative contract</u>	December 31, 2011	
	Liability Derivatives	
	Balance	Fair
	Sheet	Value
	Location	
Interest rate	Accounts Payable	\$ 25,927

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

Note M Earnings per Share

The following table reconciles the weighted-average shares outstanding for computation of basic and diluted income per Common share for each of the three years ended December 31, 2011. No difference existed between net income used in computing basic and diluted income per Common share for these years.

<i>(Weighted-average shares outstanding)</i>	2011	2010	2009
Basic method	193,409,621	191,830,357	190,767,077
Dilutive stock options	1,102,781	1,327,457	1,701,373
Diluted method	194,512,402	193,157,814	192,468,450

Outstanding options to purchase shares of Common Stock were not included in the computation of diluted earnings per share in 2009 through 2011 because the incremental shares from assumed conversion were antidilutive. These included 1,823,564 shares at a weighted average share price of \$69.46 in 2011, 2,220,567 shares at a weighted average share price of \$58.78 in 2010 and 1,793,905 shares at a weighted average share price of \$56.25 in 2009.

Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued****Note N Other Financial Information**

INVENTORIES Inventories accounted for under the LIFO method totaled \$188,390,000 and \$345,449,000 at December 31, 2011 and 2010, respectively, and these amounts were \$580,238,000 and \$735,091,000 less than such inventories would have been valued using the FIFO method. A significant inventory reduction occurred in 2011 associated with sale of the two U.S. refineries. The impact of liquidating inventories associated with the sale of the two U.S. refineries, which was mostly derived from fair value exceeding the LIFO carrying value, increased pretax income from discontinued operations by \$296,185,000 in 2011.

ACCUMULATED OTHER COMPREHENSIVE INCOME At December 31, 2011 and 2010, the components of Accumulated Other Comprehensive Income were as follows.

<i>(Thousands of dollars)</i>	2011	2010
Foreign currency translation gains	\$ 496,161	587,408
Retirement and postretirement plan adjustments, net of tax	(168,889)	(137,980)
Loss deferred on interest rate hedges, net of tax	(16,852)	0
Balance at end of year	\$ 310,420	449,428

At December 31, 2011, components of the net foreign currency translation gains of \$496,161,000 were gains (losses) of \$464,736,000 for Canadian dollars, \$37,544,000 for pounds sterling and \$(6,119,000) for other currencies. Net gains (losses) from foreign currency transactions, including the effects of foreign currency contracts, included in the Consolidated Statements of Income were \$22,131,000 in 2011, \$(63,861,000) in 2010 and \$48,429,000 in 2009.

CASH FLOW DISCLOSURES Cash income taxes paid were \$938,944,000, \$585,759,000 and \$501,506,000 in 2011, 2010 and 2009, respectively. Interest paid, net of amounts capitalized, was \$38,120,000, \$35,452,000 and \$21,017,000 in 2011, 2010 and 2009, respectively.

Noncash operating working capital (increased) decreased during each of the three years ended December 31, 2011 as follows.

<i>(Thousands of dollars)</i>	2011	2010	2009
Accounts receivable	\$ (43,630)	(4,363)	(402,481)
Inventories	(59,413)	(28,231)	(114,569)
Prepaid expenses	20,548	14,567	7,209
Deferred income tax assets	8,488	(80,073)	14,772
Accounts payable and accrued liabilities	(478,029)	766,067	365,257
Current income tax liabilities	(273,118)	(28,401)	(64,878)
Net (increase) decrease in noncash operating working capital	\$ (825,154)	639,566	(194,690)

Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued****Note O Assets and Liabilities Measured at Fair Value**

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

The fair value measurements for these assets and liabilities at December 31, 2011 and 2010 are presented in the following table.

<i>(Thousands of dollars)</i>	Fair Value at December 31, 2011	Fair Value Measurements at Reporting Date Using		
		Quoted Prices in Active Markets for Identical Assets (Liabilities) (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets				
Commodity derivative contracts	\$ 197	0	197	0
Liabilities				
Nonqualified employee savings plan	(8,030)	(8,030)	0	0
Foreign currency exchange derivative contracts	(8,459)	0	(8,459)	0
Commodity derivative contracts	(489)	0	(489)	0
Interest rate derivative contracts	(25,927)	0	(25,927)	0
Total	(42,905)	(8,030)	(34,875)	0

<i>(Thousands of dollars)</i>	Fair Value at December 31, 2010	Fair Value Measurements at Reporting Date Using		
		Quoted Prices in Active Markets for Identical Assets (Liabilities) (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets				
Foreign currency exchange derivative contracts	\$ 7,261	0	7,261	0
Commodity derivative assets	750	0	750	0
Total	8,011	0	8,011	0

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Liabilities				
Nonqualified employee savings plan	(7,672)	(7,672)	0	0
Commodity derivative contracts	(626)	0	(626)	0
Total	(8,298)	(7,672)	(626)	0

At the balance sheet dates the fair value of commodity derivatives contracts for crude oil was determined based on market quotes for WTI crude and the fair value of commodity derivative contracts for corn and wet and dried distillers grain with solubles was determined based on market quotes for No. 2 yellow corn. The fair value of derivative contracts for foreign currency exchange and interest rates was based on quotes from active brokers in the respective markets. The change in fair value of commodity derivatives is recorded in Crude Oil and Product Purchases and the change in fair value of foreign currency exchange derivatives is recorded in Interest and Other

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Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued**

Income (Loss). The interest rate derivative contracts are accounted for under hedge accounting rules; therefore, gains and losses are deferred and are recorded net of income taxes as a component of Accumulated Other Comprehensive Income in the Consolidated Balance Sheet. The nonqualified employee savings plan is an unfunded savings plan through which the participants seek a return via phantom investments in equity securities and/or mutual funds. The fair value of this savings plan liability was based on quoted prices for these equity securities and mutual funds. The income effect of the changes in the fair value of nonqualified employee savings plan is recorded in Selling and General Expense in the Consolidated Statement of Income. The carrying value of the Company's Cash and Cash Equivalents, Accounts Receivable and Accounts Payable approximates fair value.

The assets of ethanol plants acquired in 2009 and 2010 were recorded at fair value based on valuation techniques including the cost and income approaches using Level 3 unobservable inputs within the fair value hierarchy.

The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2011 and 2010. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties. The table excludes cash and cash equivalents, trade accounts receivable, short-term notes payable, trade accounts payable and accrued expenses, all of which had fair values approximating carrying amounts. The carrying value of Canadian government securities is determined based on cost plus earned interest. The fair value of current and long-term debt was estimated based on rates offered to the Company at that time for debt of the same maturities. The Company has off-balance sheet exposures relating to certain financial guarantees and letters of credit. The fair value of these, which represents fees associated with obtaining the instruments, was nominal.

	At December 31,			
	2011		2010	
(Thousands of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets (liabilities):				
Canadian government securities with maturities greater than 90 days at the date of acquisition	\$ 532,093	532,899	616,558	617,372
Current and long-term debt	(599,558)	(715,208)	(939,391)	(1,064,225)

Note P Hurricane and Insurance Related Matters

The Company maintains insurance coverage related to losses of production and profits for occurrences such as storms, fires and other issues. During 2009, the Company's North American refining and marketing operations recorded a benefit of \$15,398,000 for business interruption insurance received relating to a fire that occurred at the Meraux, Louisiana refinery in June 2003.

The Company also maintains certain insurance covering property damage, sudden and accidental environmental events and other hazards. In 2009, the Company's primary property insurer settled all claims for damages at the Meraux refinery and other properties caused by Hurricane Katrina, which struck the U.S. Gulf Coast in late August 2005. The insurer's claims for Hurricane Katrina exceeded its maximum loss for a specific event, which ultimately limited the amount of insurance the Company received for its damages. The Company's final cash settlement from the insurer led to pretax income of \$12,718,000 in 2009. This benefit arose because the ultimate cash settlements received from the insurer exceeded amounts originally estimated by the insurer.

The Company also settled with an insurance consortium in 2009 for its claims related to a crude oil spill that occurred at the Meraux refinery after Hurricane Katrina. The settlement led to pretax income of \$6,500,000 in 2009 with \$4,500,000 related to the insurance claim and \$2,000,000 of associated interest income. During 2010,

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the Company received \$3,000,000 to settle its claim against one insurer for legal and other professional costs associated with the insurance coverage negotiation process. These insurance settlements in 2009 and 2010 have been included in Income From Discontinued Operations in the respective year's Consolidated Statement of Income.

Note Q Commitments

The Company has entered into forward sales contracts to mitigate the price risk for a portion of its 2012 natural gas sales volumes from the Tupper and Tupper West areas in Western Canada. The contract calls for natural gas deliveries of approximately 50 million cubic feet per day during 2012 at an average price of Cdn\$4.43 per thousand cubic feet at the AECO C sales point. These contracts have been accounted for as a normal sale for accounting purposes.

The Company leases land, gasoline stations, and production and other facilities under operating leases. The most significant operating leases are associated with floating, production, storage and offloading facilities at the Kikeh and Azurite oil fields, production facilities at the Thunder Hawk and West Patricia fields, certain motor fuel stations in the U.K. and land under a portion of gasoline stations in the U.S. During the next five years, expected future rental payments under all operating leases are approximately \$161,752,000 in 2012, \$138,121,000 in 2013, \$127,044,000 in 2014, \$115,708,000 in 2015 and \$34,525,000 in 2016. Rental expense for noncancellable operating leases, including contingent payments when applicable, was \$185,016,000 in 2011, \$178,410,000 in 2010 and \$124,693,000 in 2009.

The Company has entered into contracts to hire various drilling rigs and associated equipment for periods beyond December 31, 2011. These rigs will primarily be utilized for drilling operations in the Gulf of Mexico, onshore U.S. and Canada, offshore Malaysia, Kurdistan, Australia and Republic of the Congo. Future commitments under these contracts, all of which expire by 2015, total approximately \$515,292,000. A significant portion of these costs are expected to be borne by other working interest owners as partners of the Company when the wells are drilled. These drilling costs are generally expected to be accounted for as capital expenditures as incurred during the contract periods.

The Company has operating, production handling and transportation agreements providing for processing, production handling and transportation services for natural gas in Western Canada. These agreements require minimum monthly or annual payments for processing and/or transportation charges through 2018. Future required minimum monthly payments for the next five years are \$23,823,000 in 2012, \$18,146,000 in 2013, \$18,452,000 in 2014, \$16,676,000 in 2015 and \$11,800,000 in 2016. Under certain circumstances, the Company is required to pay additional amounts depending on the actual hydrocarbon quantities processed under the agreement. Costs incurred under these arrangements were \$24,791,000 in 2011, \$10,337,000 in 2010 and \$11,860,000 in 2009.

Additionally, the Company has a Reserved Capacity Service Agreement providing for the availability of needed crude oil storage capacity for certain oil fields through 2020. Under the agreement, the Company must make specified minimum payments monthly. Future required minimum annual payments are approximately \$1,000,000 in 2012 through 2016. In addition, the Company is required to pay additional amounts depending on actual crude oil quantities stored under the agreement. Total payments under the agreement were \$918,000 in 2011, \$3,202,000 in 2010 and \$2,743,000 in 2009.

In 2006, the Company committed to fund an educational assistance program known as the El Dorado Promise. Under this commitment, the Company will pay \$5,000,000 per year from 2007 to 2016 to provide scholarships for a specified amount of college expenses for eligible graduates of El Dorado High School in Arkansas. The first

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS **Continued**

six payments have been made through January 2012. The Company recorded a discounted liability of \$38,700,000 in 2006 for this unconditional commitment. The liability was discounted at the Company's 10-year borrowing rate and the discounted liability increases for accretion monthly with a corresponding charge to Selling and General Expenses in the Consolidated Statement of Income. Total accretion cost included in Selling and General Expense was \$1,317,000 in 2011, \$1,534,000 in 2010 and \$1,739,000 in 2009.

Commitments for capital expenditures were approximately \$1,849,100,000 at December 31, 2011, including \$839,500,000 for field development and future work commitments in Malaysia, \$149,700,000 for costs to develop deepwater Gulf of Mexico fields, \$124,500,000 for work in the Eagle Ford Shale and \$127,500,000 for future work commitments offshore Brunei.

Note R Contingencies

The Company's operations and earnings have been and may be affected by various forms of governmental action both in the United States and throughout the world. Examples of such governmental action include, but are by no means limited to: tax increases and retroactive tax claims; royalty and revenue sharing increases; import and export controls; price controls; currency controls; allocation of supplies of crude oil and petroleum products and other goods; expropriation of property; restrictions and preferences affecting the issuance of oil and gas or mineral leases; restrictions on drilling and/or production; laws and regulations intended for the promotion of safety and the protection and/or remediation of the environment; governmental support for other forms of energy; and laws and regulations affecting the Company's relationships with employees, suppliers, customers, stockholders and others. Because governmental actions are often motivated by political considerations, may be taken without full consideration of their consequences, and may be taken in response to actions of other governments, it is not practical to attempt to predict the likelihood of such actions, the form the actions may take or the effect such actions may have on the Company.

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

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

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

The Company's liability for remedial obligations includes certain amounts that are based on anticipated regulatory approval for proposed remediation of former refinery waste sites. Although regulatory authorities may require more costly alternatives than the proposed processes, the cost of such potential alternative processes is not expected to exceed the accrued liability by a material amount. Certain environmental expenditures are likely to be recovered by the Company from other sources, primarily environmental funds maintained by certain states. Since no assurance can be given that future recoveries from other sources will occur, the Company has not recorded a benefit for likely recoveries at December 31, 2011.

The U.S. Environmental Protection Agency (EPA) currently considers the Company to be a Potentially Responsible Party (PRP) at one Superfund site. The potential total cost to all parties to perform necessary remedial work at this site may be substantial. However, based on current negotiations and available information, the Company believes that it is a de minimis party as to ultimate responsibility at the Superfund site. Accordingly, the Company has not recorded a liability for remedial costs at the Superfund site at December 31, 2011. The Company could be required to bear a pro rata share of costs attributable to nonparticipating PRPs or could be assigned additional responsibility for remediation at this site or other Superfund sites. The Company believes that its share of the ultimate costs to clean-up this Superfund site will be immaterial and will not have a material adverse effect on its net income, financial condition or liquidity in a future period.

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

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

OTHER MATTERS In the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide financial guarantees or letters of credit that may be drawn upon if the Company fails to perform under those contracts. At December 31, 2011, the Company had contingent liabilities of \$7,798,000 under a financial guarantee and \$162,906,000 on outstanding letters of credit. The Company has not accrued a liability in its balance sheet related to the guarantee and the letters of credit because it is believed that the likelihood of having these drawn is remote.

Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued****Note S Terra Nova Working Interest Redetermination**

The joint agreement between the owners of the Terra Nova field, offshore Eastern Canada, required a one-time redetermination of working interests based on an analysis of reservoir quality among fault separated areas where varying ownership interests existed. Under the redetermination, which was essentially completed in 2010, the Company's working interest at Terra Nova was reduced from its original 12.0% to 10.475% effective in January 2011. The Company made a cash settlement payment to certain Terra Nova partners in January 2011 to equalize all partners' interest in the field since about February 2005 related to the Company's working interest reduction. The Company recorded expense of \$18,582,000 in 2010 and \$83,498,000 in 2009 based on the anticipated working interest reduction. Based on the final settlement paid in 2011, the Company recorded a pretax benefit of \$5,351,000 in 2011 due to the ultimate cost of the redetermination settlement being less than originally estimated. The 2009 and 2010 expense and the 2011 benefit have been reflected as Redetermination of Terra Nova Working Interest in the Consolidated Statements of Income.

Note T Common Stock Issued and Outstanding

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2011 is shown below.

(Number of shares outstanding)	2011	2010	2009
At beginning of year	192,836,008	191,115,378	190,713,806
Stock options exercised	615,674	1,495,926	548,659
Employee stock purchase and thrift plans	33,390	49,657	61,575
Restricted stock awards, net of forfeitures	238,136	175,047	(208,662)
At end of year	193,723,208	192,836,008	191,115,378

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Note U Business Segments

Murphy's reportable segments are organized into two major types of business activities, each subdivided into geographic areas of operations. The Company's exploration and production activity is subdivided into segments for the United States, Canada, Malaysia, the United Kingdom, Republic of the Congo and all other countries; each of these segments derives revenues primarily from the sale of crude oil and/or natural gas. The Company's refining and marketing segments are disclosed geographically for the United States and the United Kingdom and each derives revenue mainly from the sale of petroleum products and merchandise. The United States business also derives revenue from production and sale of ethanol and corn by-products. The Company sells gasoline in the United States at retail stations built primarily at Walmart Supercenters. The Company's management evaluates segment performance based on income from operations, excluding interest income and interest expense. Intersegment transfers of crude oil, natural gas and petroleum products are at market prices and intersegment services are recorded at cost. Discontinued operations primarily include the activities of two U.S. refineries and associated marketing assets sold in 2011. These operations formerly comprised most of the United States Manufacturing segment that was previously reported before the refinery sales. With the sale of the two U.S. refineries in 2011, all continuing operations for U.S. downstream have been reported in the current United States Refining and Marketing segment. Results for the two U.S. refineries for 2010 and 2009 have been reclassified as discontinued operations. Discontinued operations in 2009 also included income of \$97,104,000 from the formerly held Ecuador exploration and production operations.

Information about business segments and geographic operations is reported in the following tables. For geographic purposes, revenues are attributed to the country in which the sale occurs. The Company had no single customer from which it derived more than 10% of its revenues. Corporate and other activities, including interest income, miscellaneous gains and losses, interest expense and unallocated overhead, are shown in the tables to reconcile the business segments to consolidated totals. As used in the table on the following page, Certain Long-Lived Assets at December 31 exclude investments, noncurrent receivables, deferred tax assets and goodwill and other intangible assets.

Excise taxes on petroleum products of \$3,566,876,000, \$3,375,509,000 and \$3,595,238,000 for the years 2011, 2010 and 2009, respectively, that were collected by the Company and remitted to various government entities by continuing operations were excluded from revenues and costs and expenses.

Table of Contents**Segment Information**

<i>(Millions of dollars)</i>	Exploration and Production						Total
	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Other	
Year ended December 31, 2011							
Segment income (loss)	\$ 152.7	328.0	812.7	11.5	(385.3)	(293.9)	625.7
Revenues from external customers	737.7	1,145.8	2,045.6	107.3	148.8	24.6	4,209.8
Intersegment revenues	0.0	142.8	0.0	0.0	0.0	0.0	142.8
Interest income	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Interest expense, net of capitalization	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income tax expense (benefit)	86.5	135.5	434.9	46.8	16.4	7.5	727.6
Significant noncash charges (credits)							
Depreciation, depletion, amortization	183.0	326.0	357.3	13.7	87.8	1.9	969.7
Accretion of asset retirement obligations	9.9	12.5	10.6	3.0	0.5	0.3	36.8
Amortization of undeveloped leases	62.2	28.8	0.0	0.0	0.0	27.2	118.2
Impairment of long-lived assets	0.0	0.0	0.0	0.0	368.6	0.0	368.6
Deferred and noncurrent income taxes	54.2	39.6	84.6	14.6	(0.9)	(0.1)	192.0
Additions to property, plant, equipment	696.6	885.2	694.8	19.7	79.6	20.6	2,396.5
Total assets at year-end	2,227.6	3,746.8	3,826.9	214.1	257.5	74.1	10,347.0
Year ended December 31, 2010							
Segment income (loss)	\$ 72.7	213.8	659.4	30.5	(77.2)	(92.3)	806.9
Revenues from external customers	659.9	780.2	1,837.9	133.6	155.7	3.9	3,571.2
Intersegment revenues	0.0	118.9	0.0	0.0	0.0	0.0	118.9
Interest income	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Interest expense, net of capitalization	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income tax expense (benefit)	30.0	79.1	414.1	32.6	20.6	0.5	576.9
Significant noncash charges (credits)							
Depreciation, depletion, amortization	281.1	225.5	379.0	22.4	95.5	1.5	1,005.0
Accretion of asset retirement obligations	6.9	11.2	9.8	2.3	0.4	0.5	31.1
Amortization of undeveloped leases	68.5	33.7	0.0	0.0	0.0	5.8	108.0
Deferred and noncurrent income taxes	(48.6)	34.5	145.5	(11.4)	(0.9)	0.0	119.1
Additions to property, plant, equipment	369.4	804.4	467.9	(4.7)	163.6	49.8	1,850.4
Total assets at year-end	1,651.3	3,242.6	3,333.1	187.9	678.9	88.9	9,182.7
Year ended December 31, 2009							
Segment income (loss)	\$ 178.0	64.8	561.9	12.6	(20.6)	(104.9)	691.8
Revenues from external customers	708.6	635.2	1,526.4	61.6	16.5	2.4	2,950.7
Intersegment revenues	0.0	85.3	0.0	0.0	0.0	0.0	85.3
Interest income	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Interest expense, net of capitalization	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income tax expense (benefit)	88.4	21.0	354.1	11.9	1.3	(0.6)	476.1
Significant noncash charges (credits)							
Depreciation, depletion, amortization	246.5	199.9	304.1	12.4	11.5	1.4	775.8
Accretion of asset retirement obligations	6.8	8.6	7.8	1.6	0.1	0.6	25.5
Amortization of undeveloped leases	34.7	44.1	0.0	0.0	0.0	4.4	83.2
Impairment of long-lived assets	5.2	0.0	0.0	0.0	0.0	0.0	5.2
Deferred and noncurrent income taxes	(4.6)	(7.2)	77.6	(0.9)	0.0	(0.1)	64.8
Additions to property, plant, equipment	336.8	330.1	739.0	17.2	194.9	7.6	1,625.6
Total assets at year-end	1,679.7	2,507.8	3,249.6	209.0	516.7	33.5	8,196.3

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Geographic Information

Certain Long-Lived Assets at December 31

<i>(Millions of dollars)</i>	United	Canada	Malaysia	United	Republic	Other	Total
	States			Kingdom	of the		
2011	\$ 2,953.1	3,493.4	3,154.8	694.7	133.7	52.2	10,481.9
2010	3,178.8	3,028.8	2,807.0	706.3	579.4	74.3	10,374.6
2009	2,907.2	2,324.6	2,714.9	704.7	399.9	20.5	9,071.8

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Table of Contents**Segment Information (Continued)**

<i>(Millions of dollars)</i>	Refining and Marketing			Corporate and Other	Discontinued Operations	Consolidated
	United States	United Kingdom	Total			
Year ended December 31, 2011						
Segment income (loss)	\$ 223.6	(33.3)	190.3	(75.1)	131.8	872.7
Revenues from external customers	17,471.9	6,030.3	23,502.2	33.5	0.0	27,745.5
Intersegment revenues	0.0	0.0	0.0	0.0	0.0	142.8
Interest income	0.0	0.0	0.0	10.1	0.0	10.1
Interest expense, net of capitalization	0.0	0.0	0.0	40.7	0.0	40.7
Income tax expense (benefit)	146.6	(12.1)	134.5	(52.0)	0.0	810.1
Significant noncash charges (credits)						
Depreciation, depletion, amortization	68.3	46.7	115.0	8.7	0.0	1,093.4
Accretion of asset retirement obligations	0.9	0.0	0.9	0.0	0.0	37.7
Amortization of undeveloped leases	0.0	0.0	0.0	0.0	0.0	118.2
Impairment of long-lived assets	0.0	0.0	0.0	0.0	0.0	368.6
Deferred and noncurrent income taxes	28.5	(5.3)	23.2	(43.6)	0.0	171.6
Additions to property, plant, equipment	100.1	22.2	122.3	5.3	48.1	2,572.2
Total assets at year-end	1,806.5	1,193.8	3,000.3	790.8	0.0	14,138.1
Year ended December 31, 2010						
Segment income (loss)	\$ 165.3	(34.7)	130.6	(157.9)	18.5	798.1
Revenues from external customers	13,750.4	2,905.0	16,655.4	(56.9)	0.0	20,169.7
Intersegment revenues	0.0	0.0	0.0	0.0	0.0	118.9
Interest income	0.0	0.0	0.0	6.9	0.0	6.9
Interest expense, net of capitalization	0.0	0.0	0.0	34.7	0.0	34.7
Income tax expense (benefit)	101.8	(22.3)	79.5	(47.2)	0.0	609.2
Significant noncash charges (credits)						
Depreciation, depletion, amortization	60.1	41.4	101.5	8.0	0.0	1,114.5
Accretion of asset retirement obligations	0.8	0.0	0.8	0.0	0.0	31.9
Amortization of undeveloped leases	0.0	0.0	0.0	0.0	0.0	108.0
Deferred and noncurrent income taxes	5.1	3.2	8.3	7.8	0.0	135.2
Additions to property, plant, equipment	221.0	69.1	290.1	5.9	117.3	2,263.7
Total assets at year-end	2,996.6	1,113.6	4,110.2	940.3	0.0	14,233.2
Year ended December 31, 2009						
Segment income (loss)	\$ 65.5	(20.5)	45.0	(23.0)	123.8	837.6
Revenues from external customers	11,116.4	2,725.9	13,842.3	102.2	0.0	16,895.2
Intersegment revenues	0.0	0.0	0.0	0.0	0.0	85.3
Interest income	0.0	0.0	0.0	51.7	0.0	51.7
Interest expense, net of capitalization	0.0	0.0	0.0	24.4	0.0	24.4
Income tax expense (benefit)	42.3	(1.0)	41.3	4.2	0.0	521.6
Significant noncash charges (credits)						
Depreciation, depletion, amortization	55.4	33.8	89.2	6.0	0.0	871.0
Accretion of asset retirement obligations	0.7	0.0	0.7	0.0	0.0	26.2
Amortization of undeveloped leases	0.0	0.0	0.0	0.0	0.0	83.2
Impairment of long-lived assets	0.0	0.0	0.0	0.0	0.0	5.2
Deferred and noncurrent income taxes	9.5	15.9	25.4	5.0	0.0	95.2
Additions to property, plant, equipment	161.6	101.8	263.4	23.0	113.3	2,025.3
Total assets at year-end	2,490.6	939.8	3,430.4	1,129.7	0.0	12,756.4

Geographic Information

Revenues from External Customers for the Year

<i>(Millions of dollars)</i>	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Other	Total
2011	\$ 18,184.0	1,180.3	2,063.0	6,144.8	148.8	24.6	27,745.5
2010	14,386.6	809.3	1,793.8	3,018.7	156.5	4.8	20,169.7
2009	11,855.9	652.5	1,526.4	2,838.7	16.5	5.2	16,895.2

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

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

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

In 2008, the U.S. Securities and Exchange Commission (SEC) adopted new definitions and rules for oil and gas reserves that became effective for the Company as of December 31, 2009. In January 2010, the Financial Accounting Standards Board (FASB) issued guidance that aligned its oil and gas reserves reporting requirements with the SEC's guidance. The SEC and FASB now define proved reserves as those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic method is used for the estimation. Proved developed oil and gas reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well, or through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. The new rules have expanded oil and gas producing activities to include non-traditional and unconventional resources such as the Company's 5% interest in synthetic oil operations at Syncrude in Western Canada. Therefore, net oil reserves after royalties for this synthetic oil operations have been included as a separate column in the proved oil reserves schedule beginning at December 31, 2009. The rules also now requires expanded disclosures of proved undeveloped reserves, to include discussion of such reserves held for five or more years, plus disclosures of the Company's controls over the oil and gas reserves processes, including the qualifications of the chief technical person who oversees the Company's reserves process. The rules also now permit companies to voluntarily disclose probable and possible reserves in SEC filings, but the Company has elected not to provide these voluntary disclosures.

Murphy has utilized reliable geologic and engineering technology in 2011 to include proved undeveloped reserves more than one location from producing wells in the more developed portions of the Eagle Ford Shale. The study incorporated public and proprietary data from multiple sources and encompassed the entire basin. This included analysis of seismic data, well log data, test production and fluids properties to establish geologic consistency as well as significant statistical performance data yielding predictable and repeatable reserve estimates within certain analogous areas. These locations were limited to only those areas with both established geologic consistency and sufficient statistical performance data where such data could be demonstrated to provide reasonable certain results.

As discussed above, Murphy now includes synthetic crude oil from its 5% interest in the Syncrude project in Alberta, Canada in its proved oil reserves. This operation involves a process of mining tar sands and converting the raw bitumen into a pipeline-quality crude. The proved reserves associated with this project are estimated

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

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

Oil and natural gas reserves in Malaysia are associated with production sharing contracts for Blocks SK 309/311 and K. Malaysia reserves include oil and gas to be received for both cost recovery and profit provisions under the contracts. Oil and natural gas reserves associated with the production sharing contracts in Malaysia totaled 104.4 million barrels and 347.8 billion cubic feet, respectively, at December 31, 2011. Approximately 94.0 billion cubic feet of natural gas proved reserves in Malaysia relate to fields in Block K for which the Company expects to receive sale proceeds of approximately \$0.24 per thousand cubic foot. Oil reserves attributable to a production sharing agreement in Republic of the Congo amounted to 2.3 million barrels at December 31, 2011.

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

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

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future cash flows because prices, costs and governmental policies do not remain static; appropriate discount rates may vary; and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts. Generally accepted accounting principles require that unweighted average oil and natural gas prices in effect at the beginning of each month of the year be used for calculation of the standardized measure of discounted future net cash flows.

Schedule 5 also presents the principal reasons for change in the standardized measure of discounted future net cash flows for each of the three years ended December 31, 2011.

Table of Contents**Schedule 1 Summary of Proved Oil Reserves Based on Year-End Prices for 2008 and Average Prices for 2009 - 2011**

(Millions of barrels)	Total All Products	Total by product Oil	Synthetic Oil	United States Oil	Canada Oil	Synthetic Oil	Malaysia Oil	United Kingdom Oil	Republic of the Congo Oil	Ecuador Oil
Proved developed and undeveloped oil reserves:										
December 31, 2008	173.6	173.6	0.0	26.8	24.3	0.0	100.7	17.0	0.0	4.8
Synthetic reserves presented as proved under SEC rules	131.6	0.0	131.6	0.0	0.0	131.6	0.0	0.0	0.0	0.0
Revisions of previous estimates	5.8	3.2	2.6	5.0	7.2	2.6	(4.9)	(4.1)	0.0	0.0
Improved recovery	31.0	31.0	0.0	0.0	0.0	0.0	31.0	0.0	0.0	0.0
Extensions and discoveries	23.9	23.9	0.0	0.8	3.3	0.0	11.2	0.0	8.6	0.0
Production	(48.2)	(43.5)	(4.7)	(6.2)	(7.0)	(4.7)	(27.9)	(1.2)	(0.7)	(0.5)
Sales of properties	(4.3)	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(4.3)
December 31, 2009	313.4	183.9	129.5	26.4	27.8	129.5	110.1	11.7	7.9	0.0
Revisions of previous estimates	22.5	18.0	4.5	3.5	5.4	4.5	4.4	0.4	4.3	0.0
Improved recovery	5.8	5.8	0.0	0.0	1.0	0.0	4.8	0.0	0.0	0.0
Extensions and discoveries	12.6	12.6	0.0	4.1	5.0	0.0	3.5	0.0	0.0	0.0
Production	(46.3)	(41.5)	(4.8)	(7.4)	(6.4)	(4.8)	(24.4)	(1.2)	(2.1)	0.0
December 31, 2010	308.0	178.8	129.2	26.6	32.8	129.2	98.4	10.9	10.1	0.0
Revisions of previous estimates	21.2	16.0	5.2	2.4	3.1	5.2	8.4	8.1	(6.0)	0.0
Improved recovery	14.2	14.2	0.0	0.0	0.0	0.0	10.7	3.5	0.0	0.0
Extensions and discoveries	43.9	43.9	0.0	32.6	6.7	0.0	4.6	0.0	0.0	0.0
Production	(37.6)	(32.7)	(4.9)	(6.3)	(6.0)	(4.9)	(17.7)	(0.9)	(1.8)	0.0
December 31, 2011	349.7	220.2	129.5	55.3	36.6	129.5	104.4	21.6	2.3	0.0
Proved developed oil reserves:										
December 31, 2009	270.0	150.3	119.7	18.3	26.2	119.7	90.0	11.7	4.1	0.0
December 31, 2010	248.3	129.2	119.1	15.8	28.6	119.1	66.5	10.9	7.4	0.0
December 31, 2011	238.5	118.0	120.5	20.8	32.6	120.5	57.2	5.1	2.3	0.0
Proved undeveloped oil reserves:										
December 31, 2009	43.4	33.6	9.8	8.1	1.6	9.8	20.1	0.0	3.8	0.0
December 31, 2010	59.7	49.6	10.1	10.8	4.2	10.1	31.9	0.0	2.7	0.0
December 31, 2011	111.2	102.2	9.0	34.5	4.0	9.0	47.2	16.5	0.0	0.0

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

2011 Comments for Proved Oil Reserves Changes

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

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

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

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Table of Contents**Schedule 2 Summary of Proved Natural Gas Reserves Based on Year-End Prices for 2008 and Average Prices for 2009 2011**

<i>(Billions of cubic feet)</i>	Total	United States	Canada	Malaysia	United Kingdom
Proved developed and undeveloped natural gas reserves:					
December 31, 2008	585.6	97.4	62.2	405.2	20.8
Revisions of previous estimates	77.2	9.1	(0.6)	59.4	9.3
Improved recovery	6.9	0.0	0.0	6.9	0.0
Extensions and discoveries	153.5	2.6	83.3	67.6	0.0
Production	(68.4)	(19.8)	(20.0)	(27.3)	(1.3)
Sales of properties	(0.2)	0.0	(0.2)	0.0	0.0
December 31, 2009	754.6	89.3	124.7	511.8	28.8
Revisions of previous estimates	15.2	6.6	15.2	(11.2)	4.6
Improved recovery	(1.0)	0.0	0.0	(1.0)	0.0
Extensions and discoveries	220.5	14.3	194.2	12.0	0.0
Purchases of properties	24.0	0.0	24.0	0.0	0.0
Production	(130.2)	(19.4)	(31.2)	(77.6)	(2.0)
December 31, 2010	883.1	90.8	326.9	434.0	31.4
Revisions of previous estimates	12.6	(6.3)	59.4	(32.5)	(8.0)
Improved recovery	13.8	0.0	0.0	14.8	(1.0)
Extensions and discoveries	363.5	31.1	321.5	10.9	0.0
Production	(166.9)	(17.2)	(68.9)	(79.4)	(1.4)
December 31, 2011	1,106.1	98.4	638.9	347.8	21.0
Proved developed natural gas reserves:					
December 31, 2009	401.6	73.2	89.7	209.9	28.8
December 31, 2010	586.0	67.0	210.1	277.5	31.4
December 31, 2011	711.6	58.2	427.1	210.5	15.8
Proved undeveloped natural gas reserves:					
December 31, 2009	353.0	16.1	35.0	301.9	0.0
December 31, 2010	297.1	23.8	116.8	156.5	0.0
December 31, 2011	394.5	40.2	211.8	137.3	5.2

Note: All natural gas reserves included in the table above are from consolidated subsidiaries and proportionately consolidated joint ventures.

The Company has no proved natural gas reserves attributable to investees accounted for by the equity method.

2011 Comments for Proved Natural Gas Reserves Changes

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

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

Extensions and discoveries The U.S. reserves related to the Eagle Ford Shale area of South Texas where extensive drilling occurred in 2011 and many undeveloped locations will be drilled in upcoming years. Canada reserves primarily related to Tupper West and Tupper areas in British Columbia mostly due to substantial drilling programs in 2011 and extensions for additional undeveloped locations which are planned to be

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drilled in upcoming years. Malaysia reserves include a combination of a Sarawak gas field, where three new sand reservoirs were found to be productive and were completed, and the Block K Siakap North field, which was sanctioned for development by the government and Company in 2011.

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Table of Contents**Schedule 3 Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities**

<i>(Millions of dollars)</i>	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Other	Total
Year Ended December 31, 2011							
Property acquisition costs							
Unproved	\$ 233.8	18.5	0.0	0.0	0.0	27.0	279.3
Proved	0.0	0.0	0.0	0.0	23.5	0.0	23.5
Total acquisition costs	233.8	18.5	0.0	0.0	23.5	27.0	302.8
Exploration costs*	253.2	76.0	0.7	0.5	0.5	231.6	562.5
Development costs*	263.9	871.9	705.5	30.5	78.7	3.8	1,954.3
Total costs incurred	750.9	966.4	706.2	31.0	102.7	262.4	2,819.6
Charged to expense							
Dry hole expense	0.6	50.6	0.1	0.0	18.1	181.6	251.0
Geophysical and other costs	35.9	10.2	11.0	0.5	2.9	60.2	120.7
Total charged to expense	36.5	60.8	11.1	0.5	21.0	241.8	371.7
Property additions	\$ 714.4	905.6	695.1	30.5	81.7	20.6	2,447.9
Year Ended December 31, 2010							
Property acquisition costs							
Unproved	\$ 129.8	78.6	0.0	0.0	0.0	34.4	242.8
Proved	0.0	22.0	0.0	0.0	0.0	0.0	22.0
Total acquisition costs	129.8	100.6	0.0	0.0	0.0	34.4	264.8
Exploration costs*	204.1	1.8	99.6	6.7	93.5	67.7	473.4
Development costs*	98.3	721.0	396.7	15.5	132.3	2.0	1,365.8
Total costs incurred	432.2	823.4	496.3	22.2	225.8	104.1	2,104.0
Charged to expense							
Dry hole expense	(1.4)	0.0	14.3	15.2	35.5	26.5	90.1
Geophysical and other costs	37.1	1.9	5.5	1.0	20.9	27.8	94.2
Total charged to expense	35.7	1.9	19.8	16.2	56.4	54.3	184.3
Property additions	\$ 396.5	821.5	476.5	6.0	169.4	49.8	1,919.7
Year Ended December 31, 2009							
Property acquisition costs							
Unproved	\$ 82.4	31.0	0.0	0.0	0.0	4.7	118.1
Proved	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total acquisition costs	82.4	31.0	0.0	0.0	0.0	4.7	118.1
Exploration costs*	89.7	9.9	114.4	0.1	19.1	79.4	312.6
Development costs*	197.2	321.4	695.9	15.1	187.5	2.0	1,419.1
Total costs incurred	369.3	362.3	810.3	15.2	206.6	86.1	1,849.8

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Charged to expense							
Dry hole expense	11.3	0.0	55.0	0.0	13.9	45.1	125.3
Geophysical and other costs	16.2	10.0	0.8	0.2	(3.1)	32.6	56.7
Total charged to expense	27.5	10.0	55.8	0.2	10.8	77.7	182.0
Property additions	\$ 341.8	352.3	754.5	15.0	195.8	8.4	1,667.8

* Includes non-cash asset retirement costs as follows:

2011							
Exploration costs	\$ 2.0	0.3	0.0	0.0	0.0	0.0	2.3
Development costs	15.8	20.1	0.3	10.8	2.1	0.0	49.1
	\$ 17.8	20.4	0.3	10.8	2.1	0.0	51.4

2010							
Exploration costs	\$ 3.4	0.0	0.0	0.0	0.0	0.0	3.4
Development costs	23.7	17.1	8.6	10.7	5.8	0.0	65.9
	\$ 27.1	17.1	8.6	10.7	5.8	0.0	69.3

2009							
Exploration costs	\$ 5.0	0.0	0.0	0.0	0.0	0.0	5.0
Development costs	0.0	22.2	15.5	(2.2)	0.9	0.0	36.4
	\$ 5.0	22.2	15.5	(2.2)	0.9	0.0	41.4

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

<i>(Millions of dollars)</i>	United States	Canada Conven- tional	Synthetic	Malaysia	United Kingdom	Republic of the Congo	Other	Total
Year Ended December 31, 2011								
Revenues								
Crude oil and natural gas liquids								
Sales to unaffiliated enterprises	\$ 648.8	459.2	410.2	1,583.0	92.4	148.8	0.0	3,342.4
Transfers to consolidated operations	0.0	46.4	96.4	0.0	0.0	0.0	0.0	142.8
Natural gas								
Sales to unaffiliated enterprises	71.1	280.2	0.0	461.3	14.3	0.0	0.0	826.9
Total oil and gas revenues	719.9	785.8	506.6	2,044.3	106.7	148.8	0.0	4,312.1
Other operating revenues	17.8	(3.8)	0.0	1.3	0.6	0.0	24.6	40.5
Total revenues	737.7	782.0	506.6	2,045.6	107.3	148.8	24.6	4,352.6
Costs and expenses								
Production expenses								
Production expenses	164.8	151.2	236.1	420.6	28.3	37.6	0.0	1,038.6
Exploration costs charged to expense	36.5	60.8	0.0	11.1	0.5	21.0	241.8	371.7
Undeveloped lease amortization	62.2	28.8	0.0	0.0	0.0	0.0	27.2	118.2
Depreciation, depletion and amortization	183.0	273.9	52.1	357.3	13.7	87.8	1.9	969.7
Accretion of asset retirement obligations	9.9	4.9	7.6	10.6	3.0	0.5	0.3	36.8
Impairment of properties	0.0	0.0	0.0	0.0	0.0	368.6	0.0	368.6
Terra Nova working interest redetermination	0.0	(5.4)	0.0	0.0	0.0	0.0	0.0	(5.4)
Selling and general expenses	42.1	14.2	0.9	(1.6)	3.5	2.2	39.8	101.1
Total costs and expenses	498.5	528.4	296.7	798.0	49.0	517.7	311.0	2,999.3
	239.2	253.6	209.9	1,247.6	58.3	(368.9)	(286.4)	1,353.3
Income tax expense	86.5	79.7	55.8	434.9	46.8	16.4	7.5	727.6
Results of operations	\$ 152.7	173.9	154.1	812.7	11.5	(385.3)	(293.9)	625.7
Year Ended December 31, 2010								
Revenues								
Crude oil and natural gas liquids								
Sales to unaffiliated enterprises	\$ 557.6	346.4	301.9	1,531.1	118.8	156.7	0.0	3,012.5
Transfers to consolidated operations	0.0	42.2	76.7	0.0	0.0	0.0	0.0	118.9
Natural gas								
Sales to unaffiliated enterprises	87.0	132.1	0.0	307.1	14.1	0.0	0.0	540.3
Total oil and gas revenues	644.6	520.7	378.6	1,838.2	132.9	156.7	0.0	3,671.7
Other operating revenues	15.3	(0.2)	0.0	(0.3)	0.7	(1.0)	3.9	18.4
Total revenues	659.9	520.5	378.6	1,837.9	133.6	155.7	3.9	3,690.1
Costs and expenses								
Production expenses								
Production expenses	131.7	97.5	206.4	355.0	26.9	62.0	0.0	879.5
Exploration costs charged to expense	35.7	1.9	0.0	19.8	16.2	56.4	54.3	184.3
Undeveloped lease amortization	68.5	33.7	0.0	0.0	0.0	0.0	5.8	108.0
Depreciation, depletion and amortization	281.1	180.3	45.2	379.0	22.4	95.5	1.5	1,005.0

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Accretion of asset retirement obligations	6.9	4.8	6.4	9.8	2.3	0.4	0.5	31.1
Terra Nova working interest redetermination	0.0	18.6	0.0	0.0	0.0	0.0	0.0	18.6
Selling and general expenses	33.3	10.5	0.9	0.8	2.7	(2.0)	33.6	79.8
Total costs and expenses	557.2	347.3	258.9	764.4	70.5	212.3	95.7	2,306.3
	102.7	173.2	119.7	1,073.5	63.1	(56.6)	(91.8)	1,383.8
Income tax expense	30.0	44.6	34.5	414.1	32.6	20.6	0.5	576.9
Results of operations	\$ 72.7	128.6	85.2	659.4	30.5	(77.2)	(92.3)	806.9

* Results exclude corporate overhead, interest and discontinued operations.

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Table of Contents**Schedule 4 Results of Operations for Oil and Gas Producing Activities (Continued)**

<i>(Millions of dollars)</i>	United States	Canada Conven- tional	Synthetic	Malaysia	United Kingdom	Republic of the Congo	Other	Total
Year Ended December 31, 2009								
Revenues								
Crude oil and natural gas liquids								
Sales to unaffiliated enterprises	\$ 374.8	310.7	258.1	1,478.4	54.7	24.5	0.0	2,501.2
Transfers to consolidated operations	0.0	54.9	30.4	0.0	0.0	0.0	0.0	85.3
Natural gas								
Sales to unaffiliated enterprises	80.6	68.6	0.0	45.4	6.4	0.0	0.0	201.0
Total oil and gas revenues	455.4	434.2	288.5	1,523.8	61.1	24.5	0.0	2,787.5
Other operating revenues ²	253.2	(2.2)	0.0	2.6	0.5	(8.0)	2.4	248.5
Total revenues	708.6	432.0	288.5	1,526.4	61.6	16.5	2.4	3,036.0
Costs and expenses								
Production expenses	101.2	97.9	171.9	248.2	19.9	15.4	0.0	654.5
Exploration costs charged to expense	27.5	10.0	0.0	55.8	0.2	10.8	77.7	182.0
Undeveloped lease amortization	34.7	44.1	0.0	0.0	0.0	0.0	4.4	83.2
Depreciation, depletion and amortization	246.5	171.8	28.1	304.1	12.4	11.5	1.4	775.8
Accretion of asset retirement obligations	6.8	4.3	4.3	7.8	1.6	0.1	0.6	25.5
Impairment of properties	5.2	0.0	0.0	0.0	0.0	0.0	0.0	5.2
Terra Nova working interest redetermination	0.0	83.5	0.0	0.0	0.0	0.0	0.0	83.5
Selling and general expenses	20.3	18.0	.8	(5.5)	3.0	(2.0)	23.8	58.4
Total costs and expenses	442.2	429.6	205.1	610.4	37.1	35.8	107.9	1,868.1
	266.4	2.4	83.4	916.0	24.5	(19.3)	(105.5)	1,167.9
Income tax expense (benefits)	88.4	1.2	19.8	354.1	11.9	1.3	(0.6)	476.1
Results of operations	\$ 178.0	1.2	63.6	561.9	12.6	(20.6)	(104.9)	691.8

¹ Results exclude corporate overhead, interest and discontinued operations.

² Other operating revenues in the U.S. included \$244.4 million for recovery of federal royalties paid on certain properties in the Gulf of Mexico. These royalties related to production for the years 2003 through 2009.

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

<i>(Millions of dollars)</i>	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Total
December 31, 2011						
Future cash inflows	\$ 6,105.4	18,835.5	14,110.9	2,509.5	248.6	41,809.9
Future development costs	(1,283.5)	(1,929.5)	(1,559.8)	(356.2)	(0.0)	(5,129.0)
Future production and abandonment costs	(1,417.9)	(7,199.7)	(6,161.2)	(763.0)	(183.8)	(15,725.6)
Future income taxes	(807.2)	(2,806.8)	(2,129.7)	(869.0)	(39.7)	(6,652.4)
Future net cash flows	2,596.8	6,899.5	4,260.2	521.3	25.1	14,302.9
10% annual discount for estimated timing of cash flows	(912.0)	(3,658.7)	(1,507.4)	(304.4)	2.8	(6,379.7)
Standardized measure of discounted future net cash flows	\$ 1,684.8	3,240.8	2,752.8	216.9	27.9	7,923.2
December 31, 2010						
Future cash inflows	\$ 2,472.8	13,440.2	8,118.9	1,005.1	758.9	25,795.9
Future development costs	(379.7)	(1,244.5)	(756.3)	(14.0)	(69.6)	(2,464.1)
Future production and abandonment costs	(631.3)	(6,923.3)	(2,379.0)	(305.6)	(330.7)	(10,569.9)
Future income taxes	(335.0)	(1,509.8)	(1,659.4)	(329.0)	(82.4)	(3,915.6)
Future net cash flows	1,126.8	3,762.6	3,324.2	356.5	276.2	8,846.3
10% annual discount for estimated timing of cash flows	(254.2)	(1,818.0)	(922.2)	(123.5)	(34.4)	(3,152.3)
Standardized measure of discounted future net cash flows	\$ 872.6	1,944.6	2,402.0	233.0	241.8	5,694.0
December 31, 2009						
Future cash inflows	\$ 1,908.1	9,571.1	7,496.1	831.2	467.7	20,274.2
Future development costs	(245.7)	(191.3)	(726.3)	(9.7)	(99.7)	(1,272.7)
Future production and abandonment costs	(523.6)	(5,450.6)	(1,976.1)	(330.4)	(176.5)	(8,457.2)
Future income taxes	(264.8)	(952.3)	(1,531.3)	(250.2)	(83.2)	(3,081.8)
Future net cash flows	874.0	2,976.9	3,262.4	240.9	108.3	7,462.5
10% annual discount for estimated timing of cash flows	(174.8)	(1,521.4)	(838.0)	(64.7)	(7.2)	(2,606.1)
Standardized measure of discounted future net cash flows	\$ 699.2	1,455.5	2,424.4	176.2	101.1	4,856.4

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

<i>(Millions of dollars)</i>	2011	2010	2009
Inclusion of synthetic oil reserves beginning in 2009*	\$ 0.0	0.0	378.9
Net changes in prices, production costs and development costs	(370.5)	240.1	675.1
Sales and transfers of oil and gas produced, net of production costs	(3,273.5)	(2,792.2)	(2,381.5)
Net change due to extensions and discoveries	3,300.9	1,022.2	1,976.2
Net change due to purchases and sales of proved reserves	0.0	48.7	(36.7)
Development costs incurred	1,881.5	1,271.3	1,344.1
Accretion of discount	827.7	698.9	422.1

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Revisions of previous quantity estimates	892.5	798.8	267.8
Net change in income taxes	(1,029.4)	(450.2)	(454.8)
Net increase	2,229.2	837.6	2,191.2
Standardized measure at January 1	5,694.0	4,856.4	2,665.2
Standardized measure at December 31	\$ 7,923.2	5,694.0	4,856.4

* Prior to 2009, discounted future net cash flows from synthetic oil operations were excluded from this report. With the SEC's change in the definition of proved reserves to include synthetic oil as proved reserves, the Company has included synthetic oil reserves in this table beginning in 2009.

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Table of Contents**Schedule 6 Capitalized Costs Relating to Oil and Gas Producing Activities**

<i>(Millions of dollars)</i>	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Other	Subtotal	Synthetic Oil Canada	Total
December 31, 2011									
Unproved oil and gas properties	\$ 868.0	539.9	372.8	0.0	37.4	84.2	1,902.3	0.0	1,902.3
Proved oil and gas properties	2,276.3	3,756.4	4,252.5	556.6	715.3	0.0	11,557.1	1,230.6	12,787.7
Gross capitalized costs	3,144.3	4,296.3	4,625.3	556.6	752.7	84.2	13,459.4	1,230.6	14,690.0
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	(188.2)	(223.5)	(0.0)	(0.0)	(6.1)	(41.0)	(458.8)	(0.0)	(458.8)
Proved oil and gas properties	(1,255.1)	(1,493.4)	(1,474.3)	(361.9)	(613.2)	(0.0)	(5,197.9)	(324.3)	(5,522.2)
Net capitalized costs	\$ 1,701.0	2,579.4	3,151.0	194.7	133.4	43.2	7,802.7	906.3	8,709.0
December 31, 2010									
Unproved oil and gas properties	\$ 564.7	729.0	322.4	0.0	57.9	79.6	1,753.6	0.0	1,753.6
Proved oil and gas properties	1,869.1	2,861.1	3,596.0	526.1	657.0	3.3	9,512.6	1,171.6	10,684.2
Gross capitalized costs	2,433.8	3,590.1	3,918.4	526.1	714.9	82.9	11,266.2	1,171.6	12,437.8
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	(126.5)	(200.5)	(0.0)	(0.0)	(6.0)	(13.8)	(346.8)	(0.0)	(346.8)
Proved oil and gas properties	(1,074.6)	(1,258.4)	(1,115.3)	(347.9)	(129.8)	(3.3)	(3,929.3)	(280.3)	(4,209.6)
Net capitalized costs	\$ 1,232.7	2,131.2	2,803.1	178.2	579.1	65.8	6,990.1	891.3	7,881.4

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

Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****SUPPLEMENTAL QUARTERLY INFORMATION (UNAUDITED)**

<i>(Millions of dollars except per share amounts)</i>	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Year Ended December 31, 2011					
Sales and other operating revenues	\$ 6,271.7	7,415.9	7,240.4	6,761.3	27,689.3
Income from continuing operations before income taxes	411.4	505.2	534.4	100.0	1,551.0
Income (loss) from continuing operations	238.5	280.0	335.7	(113.3)	740.9
Net income (loss)	268.9	311.6	406.1	(113.9)	872.7
Income (loss) from continuing operations per Common share					
Basic	1.23	1.45	1.74	(0.59)	3.83
Diluted	1.22	1.44	1.73	(0.59)	3.81
Net income (loss) per Common share					
Basic	1.39	1.61	2.10	(0.59)	4.51
Diluted	1.38	1.60	2.09	(0.59)	4.49
Cash dividend per Common share	0.275	0.275	0.275	0.275	1.10
Market price of Common Stock*					
High	76.11	77.48	69.71	58.67	77.48
Low	65.74	62.53	44.05	42.10	42.10
Year Ended December 31, 2010					
Sales and other operating revenues	\$ 4,699.3	4,754.9	5,209.0	5,562.6	20,225.8
Income from continuing operations before income taxes	316.2	433.6	352.7	286.2	1,388.7
Income from continuing operations	169.5	263.2	197.4	149.5	779.6
Net income	148.9	272.3	202.8	174.1	798.1
Income from continuing operations per Common share					
Basic	0.89	1.37	1.03	0.77	4.06
Diluted	0.88	1.36	1.02	0.77	4.03
Net income per Common share					
Basic	0.78	1.42	1.06	0.90	4.16
Diluted	0.77	1.41	1.05	0.90	4.13
Cash dividend per Common share	0.25	0.25	0.275	0.275	1.05
Market price of Common Stock*					
High	59.71	61.82	61.92	75.37	75.37
Low	50.13	49.55	48.44	61.01	48.44

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

Table of Contents**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****SCHEDULE II VALUATION ACCOUNTS AND RESERVES**

<i>(Millions of dollars)</i>	Balance at January 1	Charged (Credited) to Expense	Deductions	Other*	Balance at December 31
2011					
Deducted from asset accounts:					
Allowance for doubtful accounts	\$ 8.0	0.2	(0.3)	0.0	7.9
Deferred tax asset valuation allowance	305.3	140.5	0.0	0.0	445.8
2010					
Deducted from asset accounts:					
Allowance for doubtful accounts	\$ 7.8	0.5	(0.2)	(0.1)	8.0
Deferred tax asset valuation allowance	290.2	15.1	0.0	0.0	305.3
2009					
Deducted from asset accounts:					
Allowance for doubtful accounts	\$ 7.3	0.9	(0.2)	(0.2)	7.8
Deferred tax asset valuation allowance	266.8	23.4	0.0	0.0	290.2

*Amounts primarily represent changes in foreign currency exchange rates.

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GLOSSARY OF TERMS

3D seismic

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

bitumen or oil sands

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

deepwater

offshore location in greater than 1,000 feet of water

downstream

refining and marketing operations

dry hole

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

exploratory

wildcat and delineation, e.g., exploratory wells

hydrocarbons

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

synthetic oil

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

throughput

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

upstream

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

wildcat

well drilled to target an untested or unproved geologic formation

