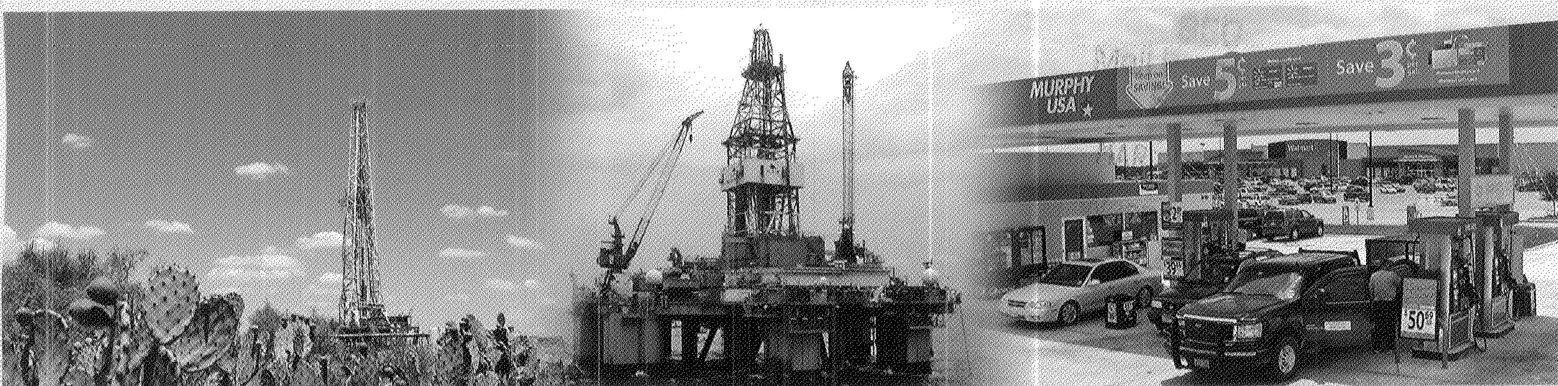
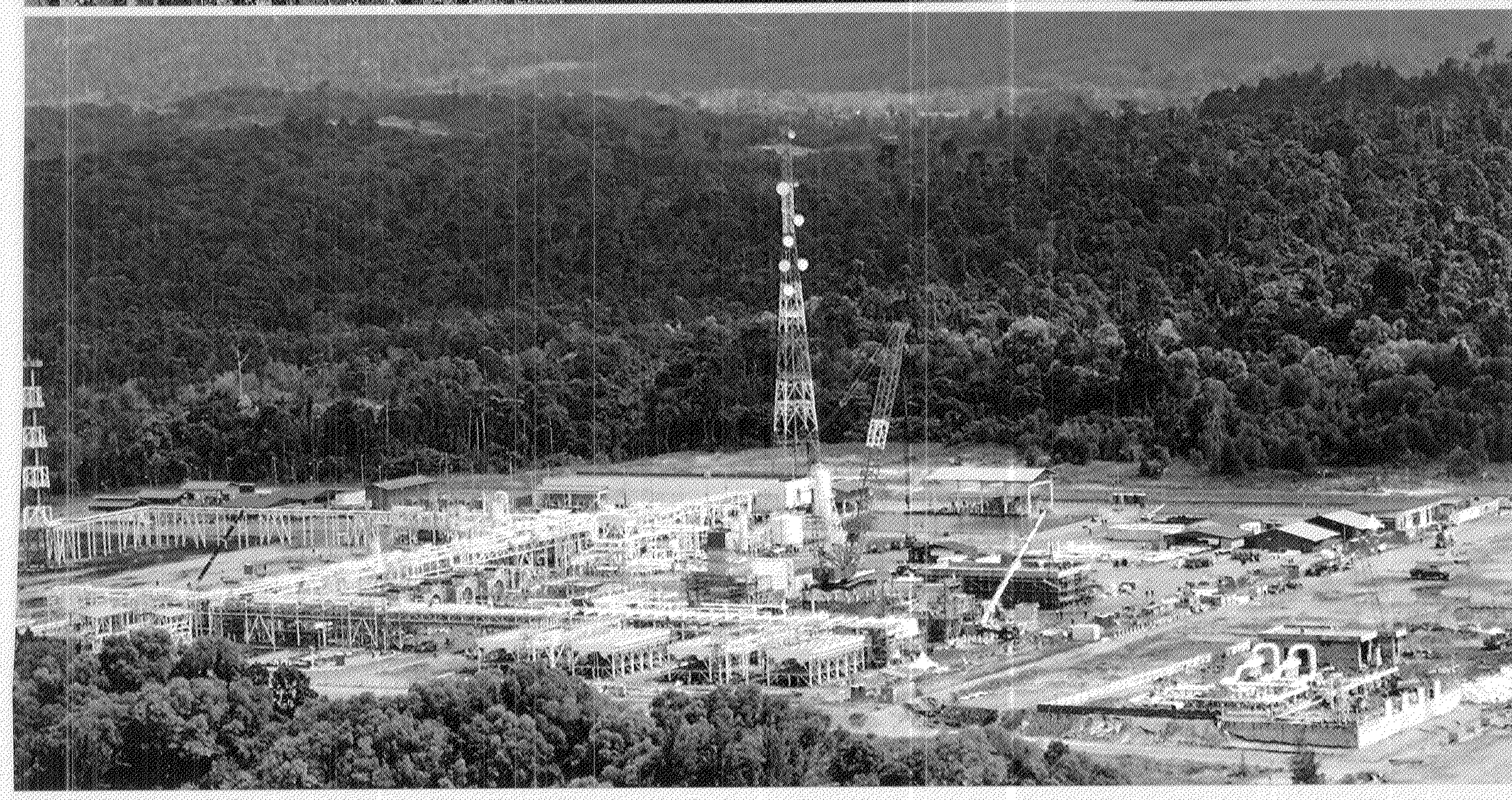
Murphy Oil Corporation

2012 Annual Report





Financial and Operating Highlights

(Thousands of dollars except per share data)	2012	2011	% Change 2012–2011	2010	% Change 2011–2010
For the Year					
Revenues	**$28,626,046**	$27,638,121	**4%**	$20,036,150	38%
Income from continuing operations	**964,046**	729,471	**32%**	749,080	-3%
Net income	**970,876**	872,702	**11%**	798,081	9%
Cash dividends paid – normal	**228,288**	212,752	**7%**	201,405	6%
– special	**486,141**	—	**N/A**	—	N/A
Capital expenditures	**4,383,986**	2,943,812	**49%**	2,448,140	20%
Net cash provided by operating activities	**3,056,281**	2,145,385	**42%**	3,128,558	-31%
Average common shares outstanding – diluted (thousands)	**194,669**	194,512	**0%**	193,158	1%
At End of Year					
Working capital	**$ 699,502**	$ 622,743	**12%**	$ 619,783	0%
Net property, plant and equipment	**13,011,606**	10,475,149	**24%**	10,367,847	1%
Total assets	**17,522,643**	14,138,138	**24%**	14,233,243	-1%
Long-term debt	**2,245,201**	249,553	**800%**	939,350	-73%
Stockholders' equity	**8,942,035**	8,778,397	**2%**	8,199,550	7%
Per Share of Common Stock					
Income from continuing operations – diluted	**$ 4.95**	$ 3.75	**32%**	$ 3.88	-3%
Net income – diluted	**4.99**	4.49	**11%**	4.13	9%
Cash dividends paid – normal	**1.175**	1.10	**7%**	1.05	5%
– special	**2.50**	—	**N/A**	—	N/A
Stockholders' equity	**46.91**	45.31	**4%**	42.52	7%
Net Crude Oil and Gas Liquids Produced – barrels per day	**112,591**	103,160	**9%**	126,927	-19%
United States	**26,090**	17,148	**52%**	20,114	-15%
Canada	**28,302**	30,049	**-6%**	30,801	-2%
Malaysia	**52,663**	48,551	**8%**	66,897	-27%
Other International	**5,536**	7,412	**-25%**	9,115	-19%
Net Natural Gas Sold – thousands of cubic feet per day	**490,124**	457,365	**7%**	356,801	28%
United States	**52,962**	47,212	**12%**	53,037	-11%
Canada	**217,046**	188,787	**15%**	85,563	121%
Malaysia	**216,745**	217,440	**0%**	212,692	2%
United Kingdom	**3,371**	3,926	**-14%**	5,509	-29%
Petroleum Products Sold – barrels per day	**474,949**	556,434	**-15%**	536,757	4%
United States	**337,900**	420,737	**-20%**	450,100	-7%
United Kingdom	**137,049**	135,697	**1%**	86,657	57%
Stockholder and Employee Data at December 31					
Common shares outstanding (thousands)	**190,641**	193,723	**-2%**	192,836	0%
Number of stockholders of record	**2,361**	2,212	**7%**	2,363	-6%
Number of employees	**9,185**	8,610	**7%**	8,994	-4%
Average number of employees for year	**8,879**	8,906	**0%**	8,673	3%

Cover photos: Clockwise from top left. A drilling rig in the Eagle Ford Shale area of South Texas; a deepwater rig drilling in Block H, offshore Sabah, Malaysia; a Company retail station at Floresville, Texas; the Bintulu natural gas processing facility in Sarawak, Malaysia

Murphy Oil at a Glance

Murphy Oil Corporation ("Murphy" or "the Company") is an international oil and gas company that conducts business through various operating subsidiaries. The Company produces oil and/or natural gas in the United States, Canada, Malaysia, the United Kingdom and Republic of the Congo and conducts exploration activities worldwide. Murphy also has an interest in a Canadian synthetic oil operation. The Company operates a growing retail gasoline marketing network on the parking lots of Walmart Supercenters and at stand-alone locations in the United States, and also markets petroleum products under various brand names and to unbranded wholesale customers in the United States. Additionally, the Company owns two ethanol production facilities in the United States. The Company owns a petroleum refinery and markets petroleum products in the United Kingdom. See further comments below regarding the Company's intention to sell its U.K. assets and separate its U.S. downstream operations. Murphy is headquartered in El Dorado, Arkansas, and has over 9,100 employees worldwide. The Company's common stock is traded on the New York Stock Exchange under the ticker symbol "MUR".

Major Subsidiaries of Murphy Oil Corporation

Murphy Exploration & Production Company, through various operating subsidiaries and affiliates, is engaged in crude oil and natural gas production activities in the United States, Malaysia, the U.K. sector of the North Sea and Republic of the Congo, and explores for oil and natural gas worldwide. The subsidiary has its headquarters in Houston, Texas, and conducts business from offices in numerous locations around the world. During 2012, the Company executed purchase and sale agreements to sell all of its U.K. exploration and production assets; these asset sales are expected to be completed in early 2013.

Murphy Oil Company Ltd. is engaged in crude oil and natural gas exploration and production in Western Canada and offshore Eastern Canada as well as the extraction and sale of synthetic crude oil from oil sands. The subsidiary's office is located in Calgary, Alberta, and is operated as a component of the Company's worldwide exploration and production operation directed from Houston.

Murphy Oil USA, Inc. is engaged in retail and wholesale marketing of petroleum products in the United States. It is headquartered in El Dorado, Arkansas. High-volume and low-cost Murphy USA® branded gasoline stations located on-site at Walmart Supercenters and at stand-alone Murphy Express locations provide fuel and merchandise to retail customers in 23 states, primarily in the Southern and Midwestern U.S. Murphy Oil USA also operates a network of seven Company-owned terminals that, along with a number of third-party terminals, supply fuel to the retail network and wholesale and bulk customers in 30 states. Ethanol production facilities in Hankinson, North Dakota, and Hereford, Texas, produce about one-third of ethanol blended into gasoline sold by the Company. The Company has announced its intention to separate this U.S. Downstream business by effecting a spin-off to its shareholders during 2013. After the separation, this business would be an independent publicly held company.

Murco Petroleum Limited is engaged in refining and marketing of petroleum products in the United Kingdom. Headquartered at St. Albans, England, Murco owns a refinery in Milford Haven, Wales, and operates a network of fueling stations in the United Kingdom. The Company has announced its intention to sell these U.K. operations.

Offices

El Dorado, Arkansas
Houston, Texas
Calgary, Alberta, Canada
Kuala Lumpur, Malaysia
St. Albans, Hertfordshire, England
Pointe-Noire, Republic of the Congo
Perth, Western Australia, Australia
Jakarta, Indonesia
Erbil, Kurdistan, Iraq
Ho Chi Minh City, Vietnam

Dear Fellow Shareholders

Steven A. Cossé
President and Chief Executive Officer

As a result of a great deal of smart, hard work and dedication by our employees in 2012, our Company achieved important year-on-year growth in production and proved reserves, in retail station count and sales volume, and in earnings and dividends. Going forward in 2013, we expect to see continued growth – and as the planned spin-off of our U.S. Retail business becomes a reality later this year, we will see it more clearly as two separate, publicly traded companies each pursue their individual growth strategies.

In our exploration and production business, production for 2012 averaged over 194,000 barrels of oil equivalent per day (boepd) with a weighting of 58% to oil and 15% to oil-indexed natural gas. This represents production growth of 8% over 2011 and a leading compound annual growth rate of nearly 14% over the last five years. Increases in production came from steady predictable growth in the Eagle Ford Shale (EFS) in south Texas, stabilized production from our Kikeh field and Sarawak gas development, both offshore Malaysia, and increased working interests in the Gulf of Mexico. Early in the year we made the decision to reduce spending and ultimately production by approximately 5,000 boepd of North American dry gas from our Montney developments in northeast British Columbia. While this resulted in lower production, it was the prudent decision in view of low natural gas prices.

In 2013 we will see another year of production growth with steady development at EFS and the offshore oil projects in Block K and Sarawak in Malaysia coming onstream late in the year.

Activity in our North America onshore business focused on oil development in the EFS and moving forward with plans for Enhanced Oil Recovery (EOR) at Seal in Canada. In the EFS, we ramped up to ten rigs early in the year and held steady at that level, drilling 151 wells for the year bringing our total well count to 213 at year-end 2012. Production from the EFS averaged over 15,000 boepd for the year, up from 3,750 boepd in 2011. We plan to maintain this steady rate of development for the foreseeable future as we target production growth to over 50,000 boepd. Our plans to grow heavy oil production at Seal are centered on EOR development related to polymer flooding and thermal stimulation. We added to our land position and resource base at Seal through an acquisition that fits well with our growth plans.

In our global offshore business, we are on track to bring new Malaysian oil developments onstream late in 2013 at Patricia, Serendah, South Acis and Permas in the Sarawak blocks and Siakap North in Sabah. In addition, the early production system for the Kakap-Gumusut project brought two wells onstream through the Kikeh facility in the fourth quarter of 2012, a year ahead of the main field. In a continuing effort to review and rationalize our portfolio, we signed Purchase and Sale agreements to sell our U.K. upstream fields at Schiehallion, Mungo-Monan and Amethyst.

Our global exploration focus is in four geographic regions on specific play types with a goal to deliver a consistent 10 well program. The 2012 program yielded solid results with seven discoveries from a total of ten wells drilled. We continued our string of success in Block H Malaysia with four discoveries bringing us to seven straight in the field where a third party floating liquefied natural gas (LNG) project is scheduled to be sanctioned in 2013. We participated at a 5% working interest in two smaller discoveries in Block CA-1 offshore Brunei and our final discovery came at our Dalmatian South prospect in the Gulf of Mexico. While not in the "grand slam" category, our steady pace of "singles" and "doubles" has contributed to over 150% production replacement over the last five years as well as a near doubling of production and the addition of 200 million barrels of oil equivalent of proved reserves. We look forward to this year's 10-plus well program where we have sizeable wells to drill in Australia, Cameroon and the Gulf of Mexico in 2013.

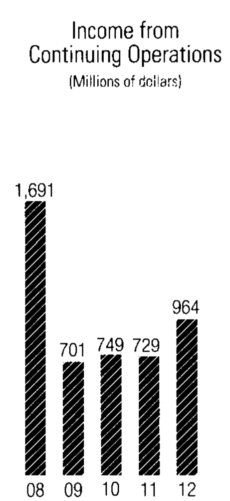
We are fortunate to have Brent as the global benchmark for the majority of our oil-weighted production as it shows continued strength, while West Texas Intermediate (WTI) remained dislocated to global benchmarks as growing domestic production resulted in an oversupply in the U.S. midcontinent. We expect the dislocation of WTI crude pricing against global benchmarks to continue for the midterm. However, with anticipated global economic recovery, we expect the supply/demand balance to remain tight and we are well positioned with our growing oil-weighted portfolio attracting Brent related pricing.

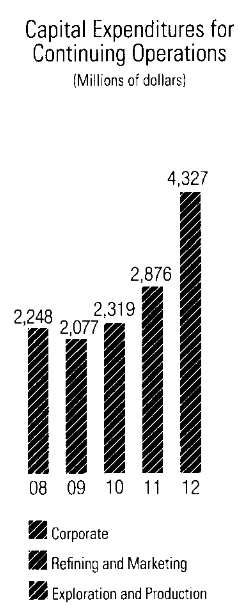
Natural gas prices in North America fell below $2.00 per million British thermal units (mmbtu) during part of 2012 as this market was oversupplied with shale gas. The Henry Hub benchmark recovered to around $3.50 per mmbtu by the end of the year. We are encouraged with recent announced LNG export projects in Canada where we have the majority of our North America dry gas position. In the near term, we will remain disciplined in our investments in North American dry gas until LNG exports for this region mature. Globally, continued strong demand for LNG provides support for solid oil-indexed pricing for our Sarawak, Malaysia gas production and should provide future growth opportunities in the region.

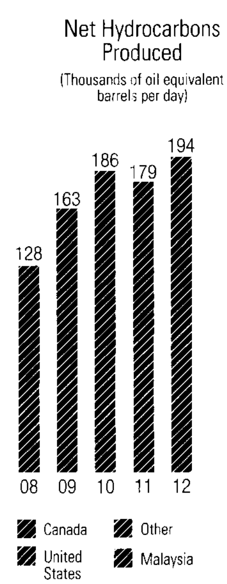
Our downstream business had another solid year turning in income of $197 million, excluding the Hereford ethanol plant impairment, and cash flow of $342 million, with the U.S. Retail business contributing the third highest net income in its history. Expansion of the retail network continued with the addition of 37 new stations in 2012, bringing the total number of retail outlets to 1,165 at year-end. We solidified our relationship with Walmart with an agreement to grow the retail network in core markets accessing over 200 new locations and providing the foundation for growth. In addition, we participated with Walmart on another promotional discount program on gasoline prices from September through December.

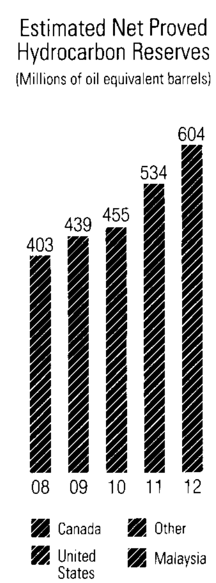
Having divested our two U.S. refineries in late 2011, we continue with the sales process for our U.K. downstream assets. During this protracted sales process, the business has continued to focus on safe reliable operations and has been able to capture margin and contribute net income through the year.

In 2012, our Company moved forward on key initiatives to unlock value for our shareholders with the plan to "spin-off" the U.S. Retail business into a separate entity, declaring a special dividend to shareholders and implementing a share repurchase program.









As a result of the planned "spin-off", scheduled for the second half of 2013, Murphy USA will continue its growth as a low-price, high-volume fuel retailer to the price conscious consumer. This fuel first business will consist of retail marketing of petroleum products and convenience merchandise through a large chain of company owned and operated retail gasoline stations, located primarily on the parking lots of the largest retailer in the world. Murphy USA is poised to become a separate entity with a growth plan in place and an advantaged retail format underpinned by low cost supply to meet the needs of our value-conscious customers.

Murphy Oil Corporation will become an independent exploration and production company with principal activities in the United States, Canada and Malaysia. It will continue its global exploration program and accompanying development projects complemented by predictable growth in our North America oil-weighted onshore business led by the EFS. The EFS is on track to become Murphy's most significant field in terms of net production with reserve potential now in excess of 300 million barrels. In the EFS we have recently cut drilling times by over 30% and continue to reduce completion costs as production maintains its steady ramp up towards 50,000-plus boepd by 2015. In addition, we are on-track with our oil development projects offshore Malaysia that will deliver substantial production growth in 2014-15.

In financial results, net income for 2012 totaled $970.9 million ($4.99 per share), up $98.2 million from 2011 primarily due to lower impairment charges and the benefit of tax deductions related to foreign exploration activity, somewhat offset by lower downstream results for the year. In August, the Board signaled support for our future growth by approving an increase to our regular dividend by 14% to an annual rate of $1.25 per share. We utilized our strong balance sheet to undertake the shareholder initiatives in the fourth quarter leaving the Company adequately capitalized to carry out our exploration and development program, ending the year with a debt-to-capital-employed ratio of 20.1%.

In closing as we look back on the performance and accomplishments of our Company over the past year, we must pause to reflect on the passing of our former Chairman, William C. Nolan, Jr., who died on March 12, 2012. Bill was an insightful leader who provided sage guidance during his 35-year tenure on the Board. He is sadly missed.

In August 2012, the Board added a capable new director in Jeffrey W. Nolan, President and CEO of Loutre Land and Timber Company. We welcome Jeff to the Board and look forward to his contributions.

David M. Wood retired as President and CEO in June 2012 after 17 years with the Company. We thank David for many contributions over his career and wish him well.

I appreciate your continued support as our Company moves forward with the spin-off of the U.S. Retail business and the creation of two strong but distinct businesses, each with a growth plan for the future. We have the team in place and together we look forward to delivering on our plans.

Steven A Cossé
President and Chief Executive Officer

February 13, 2013
El Dorado, Arkansas

Exploration and Production Statistical Summary

	2012	2011	2010	2009	2008	2007	2006
Net crude oil, condensate and natural gas liquids production – barrels per day							
United States	**26,090**	17,148	20,114	17,053	10,668	12,989	21,112
Canada – light	**245**	83	43	18	46	596	443
heavy	**7,241**	7,264	5,988	6,813	8,484	11,524	12,613
offshore	**6,986**	9,204	11,497	12,357	16,826	18,871	14,896
synthetic	**13,830**	13,498	13,273	12,855	12,546	12,948	11,701
Malaysia	**52,663**	48,551	66,897	76,322	57,403	20,367	11,298
Republic of the Congo	**2,078**	4,989	5,820	1,743	–	–	–
Continuing operations	**109,133**	100,737	123,632	127,161	105,973	77,295	72,063
Discontinued operations	**3,458**	2,423	3,295	4,678	12,281	14,227	15,754
Total liquids produced	**112,591**	103,160	126,927	131,839	118,254	91,522	87,817
Net crude oil, condensate and natural gas liquids sold – barrels per day							
United States	**26,090**	17,148	20,114	17,053	10,668	12,989	21,112
Canada – light	**245**	83	43	18	46	596	443
heavy	**7,241**	7,264	5,988	6,813	8,484	11,524	12,613
offshore	**7,092**	9,079	11,343	12,455	16,690	18,839	15,360
synthetic	**13,830**	13,498	13,273	12,855	12,546	12,948	11,701
Malaysia	**54,286**	48,092	68,975	72,575	61,907	16,018	11,986
Republic of the Congo	**1,468**	3,959	5,428	973	–	–	–
Continuing operations	**110,252**	99,123	125,164	122,742	110,341	72,914	73,215
Discontinued operations	**3,372**	2,299	4,177	3,607	13,513	14,688	17,027
Total liquids sold	**113,624**	101,422	129,341	126,349	123,854	87,602	90,242
Net natural gas sold – thousands of cubic feet per day							
United States	**52,962**	47,212	53,037	54,255	45,785	45,139	56,810
Canada	**217,046**	188,787	85,563	54,857	1,910	9,922	9,752
Malaysia – Sarawak	**174,283**	176,943	154,535	28,070	–	–	–
Kikeh	**42,462**	40,497	58,157	46,583	1,399	–	–
Continuing operations	**486,753**	453,439	351,292	183,765	49,094	55,061	66,562
Discontinued operations	**3,371**	3,926	5,509	3,501	6,424	6,021	8,700
Total natural gas sold	**490,124**	457,365	356,801	187,266	55,518	61,082	75,262
Net hydrocarbons produced – equivalent barrels[1] per day	**194,278**	179,388	186,394	163,050	127,507	101,702	100,361
Estimated net hydrocarbon reserves – million equivalent barrels[1,2]	**604.3**	534.1	455.2	439.2	402.8	405.1	388.3
Weighted average sales prices[3]							
Crude oil, condensate and natural gas liquids – dollars per barrel							
United States	**$ 102.60**	103.92	76.31	60.08	95.74	65.57	57.30
Canada[4] – light	**81.22**	94.28	75.48	64.24	70.37	50.98	50.45
heavy	**46.45**	57.00	49.89	40.45	59.05	32.84	25.87
offshore	**112.08**	110.02	76.87	58.19	96.69	69.83	62.55
synthetic	**91.85**	102.94	77.90	61.49	100.10	74.35	63.23
Malaysia[5]	**97.29**	90.14	60.97	55.51	87.83	74.58	51.78
Republic of the Congo[5]	**107.26**	103.02	74.87	69.04	–	–	–
Natural gas – dollars per thousand cubic feet							
United States	**2.76**	4.13	4.52	4.05	9.67	7.38	7.76
Canada[4]	**2.62**	4.07	4.23	3.09	6.40	6.34	6.49
Malaysia – Sarawak[5]	**7.50**	7.10	5.31	4.05	–	–	–
Kikeh	**0.24**	0.24	0.23	0.23	0.23	–	–

[1] Natural gas converted at a 6:1 ratio.

[2] At December 31.

[3] Includes intracompany transfers at market prices.

[4] U.S. dollar equivalent.

[5] Prices are net of payments under the terms of the respective production sharing contracts.

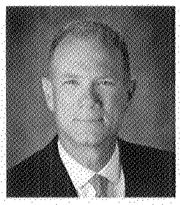
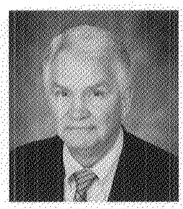
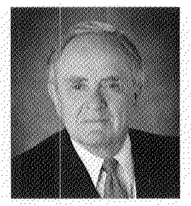
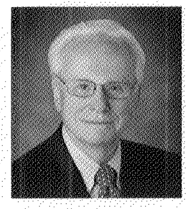
Refining and Marketing Statistical Summary

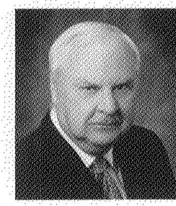
	2012	2011	2010	2009	2008	2007	2006
Branded retail refueling stations[1]							
United States – Murphy USA®	**1,015**	1,003	1,001	996	992	971	987
Murphy Express	**150**	125	98	52	33	2	–
Other	**–**	–	116	121	129	153	177
Total United States	**1,165**	1,128	1,215	1,169	1,154	1,126	1,164
United Kingdom	**452**	459	451	453	454	389	402
United States retail marketing:							
Fuel margin per gallon[2]	**$ 0.129**	0.156	0.114	0.083	0.165	0.103	0.104
Gallons sold per store month	**277,001**	277,715	306,646	312,493	324,223	294,784	285,665
Merchandise sales revenue per store month	**$ 156,429**	158,144	153,530	137,623	110,943	97,523	80,598
Merchandise margin as a percentage of merchandise sales	**13.5%**	12.8%	13.1%	12.5%	13.5%	13.2%	13.3%
United Kingdom refining and marketing –							
Unit margins per barrel	**$ 1.94**	(0.67)	(1.47)	(0.28)	3.41	(1.48)	4.43
Petroleum products sold – barrels per day							
United States – Gasoline	**289,650**	312,945	333,182	319,549	313,827	298,833	266,353
Kerosine	**146**	11,864	11,449	11,928	4,606	1,685	2,269
Diesel and home heating oils	***48,104***	*74,410*	*77,799*	*76,599*	*86,933*	*91,344*	*62,196*
Residuals	**–**	12,618	18,015	15,501	14,837	15,422	11,696
Asphalt, LPG and other	**–**	8,900	9,655	9,123	7,287	9,384	8,087
Total United States	**337,900**	420,737	450,100	432,700	427,490	416,668	350,601
United Kingdom – Gasoline	**47,087**	35,757	23,085	30,007	34,125	14,356	12,425
Kerosine	**17,273**	16,298	11,387	12,954	14,835	4,020	3,619
Diesel and home heating oils	**48,595**	48,893	29,710	35,721	34,560	14,785	11,803
Residuals	**13,744**	14,427	7,885	10,560	12,744	3,728	3,825
LPG and other	**10,350**	20,322	14,590	14,532	15,246	4,213	2,998
Total United Kingdom	**137,049**	135,697	86,657	103,774	111,510	41,102	34,670
Total petroleum products sold	**474,949**	556,434	536,757	536,474	539,000	457,770	385,271
Crude capacity of Milford Haven, Wales refinery[1] – barrels per stream day	**135,000**	135,000	135,000	108,000	108,000	108,000	32,400
Milford Haven, Wales refinery inputs – barrels per day							
Crude	**129,334**	131,959	78,841	96,625	97,521	36,000	30,036
Other feedstocks	**3,279**	3,432	5,322	6,334	15,067	3,756	3,720
Total U.K. refinery inputs	**132,613**	135,391	84,163	102,959	112,588	39,756	33,756
Milford Haven, Wales refinery yields – barrels per day							
Gasoline	**46,100**	34,171	20,889	26,902	32,290	12,397	10,624
Kerosine	**16,941**	17,038	11,374	13,789	15,065	4,500	4,255
Diesel and home heating oils	**46,004**	47,418	25,995	34,619	33,868	14,218	11,308
Residuals	**13,922**	14,185	8,296	10,388	12,585	3,641	3,830
Asphalt, LPG and other	**5,976**	19,448	14,799	13,735	15,750	4,344	2,962
Fuel and loss	**3,670**	3,131	2,810	3,526	3,030	656	777
Total U.K. refining yields	**132,613**	135,391	84,163	102,959	112,588	39,756	33,756

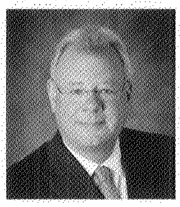
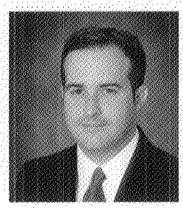
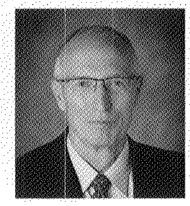
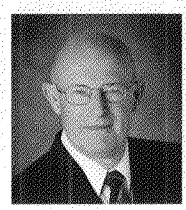
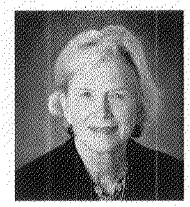
[1] At December 31.

[2] Represents net sales prices for fuel less purchased cost of fuel.

Board of Directors



Top row left to right

Claiborne P. Deming—President and Chief Executive Officer, Retired, Murphy Oil Corporation, El Dorado, Arkansas. Director since 1993. Chairman of the Board since March 2012. Committees: Executive (Chairman); Environmental, Health & Safety

Steven A. Cossé—President and Chief Executive Officer, Murphy Oil Corporation, El Dorado, Arkansas since June 2012. Director since 2011. Committees: Executive; Environmental, Health & Safety

Frank W. Blue—International Legal Advisor/Arbitrator, Santa Barbara, California. Director since 2003. Committees: Audit; Nominating & Governance

Robert A. Hermes—Chairman of the Board, Retired, Purvin & Gertz, Inc., Houston, Texas. Director since 1999. Committees: Executive; Nominating & Governance (Chairman); Environmental, Health & Safety

James V. Kelley—President and Chief Operating Officer, BancorpSouth, Inc., Tupelo, Mississippi. Director since 2006. Committees: Audit; Executive Compensation; Nominating & Governance

Walentin Mirosh—President, Mircan Resources Ltd., Calgary, Alberta, Canada. Director since 2011. Committees: Executive Compensation; Environmental, Health & Safety

Bottom row left to right

R. Madison Murphy—Managing Member, Murphy Family Management, LLC, El Dorado, Arkansas. Director since 1993. Chairman from 1994–2002. Committees: Executive; Audit (Chairman)

Jeffrey W. Nolan—President and Chief Executive Officer, Loutre Land and Timber Company, El Dorado, Arkansas. Director since 2012. Committees: Executive Compensation

Neal E. Schmale—President and Chief Operating Officer, Retired, Sempra Energy, San Diego, California. Director since 2004. Committees: Audit; Executive Compensation

David J. H. Smith—Chief Executive Officer, Retired, Whatman plc, Maidstone, Kent, England. Director since 2001. Committees: Executive Compensation (Chairman); Nominating & Governance

Caroline G. Theus—President, Inglewood Land & Development Co., Alexandria, Louisiana. Director since 1985. Committees: Executive; Environmental, Health & Safety (Chairman)

Principal Subsidiaries

Murphy Exploration & Production Company
Engages in worldwide crude oil and natural gas exploration and production.

16290 Katy Freeway
Suite 600
Houston, Texas 77094
(281) 675-9000

Roger W. Jenkins
President

Eugene T. Coleman
Executive Vice President, Offshore and International Operations

Michael McFadyen
Executive Vice President, North American Onshore Operations

Derek M. Stewart
Senior Vice President, Americas, West Africa and Middle East

Sam Algar
Vice President, Asia Pacific Exploration

Keith S. Caldwell
Vice President, Finance

Daniel R. Hanchera
Vice President, Business Development

Dave B. Perkins
Vice President, Health, Safety, Environment & Security

Walter K. Compton
Vice President and General Counsel

Kevin G. Fitzgerald
Vice President

Mindy K. West
Vice President and Treasurer

John W. Eckart
Vice President

John A. Moore
Secretary

Murphy Oil Company Ltd.
Engages in crude oil and natural gas exploration and production, and extraction and sale of synthetic crude oil in Canada.

4000, 520-3 Avenue SW
Calgary, Alberta T2P 0R3
(403) 294-8000

Mailing Address:
P.O. Box 2721, Station M
Calgary, Alberta T2P 3Y3
Canada

Michael McFadyen
President

Cal Buchanan
Vice President, Business Development

Ronald L. McIlwrick
Vice President, Operations

Dennis Ward
Vice President, Finance

Kevin Fitzgerald
Vice President

Mindy K. West
Treasurer

Paul Christensen
Controller

Linda J. Smorang
Secretary

Murphy Oil USA, Inc.
Engages in marketing of petroleum products and manufacturing of ethanol fuel in the United States.

200 Peach Street
El Dorado, Arkansas 71730
(870) 862-6411

Mailing Address:
P.O. Box 7000
El Dorado, Arkansas 71731-7000

R. Andrew Clyde
President

Marn K. Cheng
Vice President

Jeffery A. Goodwin
Vice President

Stephen F. Hunkus
Vice President

John C. Rudolfs
Vice President

Mindy K. West
Chief Financial Officer

John A. Moore
General Counsel and Secretary

Murco Petroleum Limited
Engages in refining and marketing of petroleum products in the United Kingdom.

4 Beaconsfield Road
St. Albans, Hertfordshire
AL1 3RH, England
44-1727-892-400

Bryan G. Kelly
Managing Director

John E. Ford
Planning & Special Projects Director

Jamie Goodfellow
Marketing Director

Susan Hogg
Supply and Refining Director

Simon V. Rhodes
Financial Director

Patricia E. Haylock
Secretary

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, 2012

OR

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

Commission file number 1-8590

MURPHY OIL CORPORATION
(Exact name of registrant as specified in its charter)

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

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ 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 ☒	Accelerated filer ☐
Non-accelerated filer ☐	Smaller reporting company ☐

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter (as of June 30, 2012) – $9,769,170,000.

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

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 8, 2013 have been incorporated by reference in Part III herein.

MURPHY OIL CORPORATION
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PART I

Item 1. BUSINESS

Summary

Murphy Oil Corporation is a worldwide oil and gas exploration and production company with retail and wholesale gasoline marketing operations in the United States and refining and marketing operations in the United Kingdom. As used in this report, the terms Murphy, Murphy Oil, we, our, its and Company may refer to Murphy Oil Corporation or any one or more of its consolidated subsidiaries.

The Company was originally incorporated in Louisiana in 1950 as Murphy Corporation. It was reincorporated in Delaware in 1964, at which time it adopted the name Murphy Oil Corporation, and was reorganized in 1983 to operate primarily as a holding company of its various businesses. Its operations are classified into two business activities: (1) "Exploration and Production" and (2) "Refining and Marketing." For reporting purposes, Murphy's exploration and production activities are subdivided into five geographic segments, including the United States, Canada, Malaysia, the Republic of the Congo and all other countries. Murphy's refining and marketing activities are subdivided into segments for the United States and the United Kingdom. As described further in this Form 10-K, Murphy has previously announced its intention to separate its U.S. downstream business into an independent company and to sell its U.K. downstream business. Additionally, "Corporate" activities include interest income, interest expense, foreign exchange effects and administrative costs not allocated to the segments.

The information appearing in the 2012 Annual Report to Security Holders (2012 Annual Report) is incorporated in this Form 10-K report as Exhibit 13 and is deemed to be filed as part of this Form 10-K report as indicated under Items 1, 2 and 7.

In addition to the following information about each business activity, data about Murphy's operations, properties and business segments, including revenues by class of products and financial information by geographic area, are provided on pages 27 through 49, F-15 and F-16, F-46 through F-52 and F-54 of this Form 10-K report and on pages 5 and 6 of the 2012 Annual Report.

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

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

Exploration and Production

The Company's exploration and production business explores for and produces crude oil, natural gas and natural gas liquids worldwide. The Company's exploration and production management team in Houston, Texas, directs the Company's worldwide exploration and production activities.

During 2012, Murphy's principal exploration and production activities were conducted in the United States by wholly owned Murphy Exploration & Production Company – USA (Murphy Expro USA), in Malaysia, Republic of the Congo, Indonesia, Suriname, Australia, Brunei, the Kurdistan region of Iraq, Cameroon, Vietnam and Equatorial Guinea by wholly owned Murphy Exploration & Production Company – International (Murphy Expro International) and its subsidiaries, in Western Canada and offshore Eastern Canada by wholly owned Murphy Oil Company Ltd. (MOCL) and its subsidiaries, and in the U.K. North Sea and the Atlantic Margin by wholly owned Murphy Petroleum Limited. Murphy's crude oil and natural gas liquids production in 2012 was in the United States, Canada, Malaysia, the Republic of the Congo and the United Kingdom; its natural gas was produced and sold in the United States, Canada, Malaysia and the United Kingdom. MOCL owns a 5% undivided interest in Syncrude Canada Ltd. in northern Alberta, one of the world's largest producers of synthetic crude oil.

In late 2012 the Company entered into contracts to sell its exploration and production assets in the United Kingdom; these assets sales are expected to be completed in early 2013 and the results for these operations have been reported as discontinued operations in the consolidated financial statements for all periods presented.

Unless otherwise indicated, all references to the Company's oil and gas production volumes and proved oil and gas reserves are net to the Company's working interest excluding applicable royalties.

Murphy's worldwide crude oil, condensate and natural gas liquids production in 2012 averaged 112,591 barrels per day, an increase of 9% compared to 2011. The increase was primarily due to higher 2012 oil production in the Eagle Ford Shale area of South Texas and at the Kikeh field, offshore Sabah Malaysia. The Company's worldwide sales volume of natural gas averaged 490 million cubic feet (MMCF) per day in 2012, up 7% from 2011 levels. The higher natural gas sales volume in 2012 was primarily attributable to increased natural gas production in the Tupper area in Western Canada, where more wells were producing for a longer period in 2012 versus the prior year. Total worldwide 2012 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 194,278 barrels per day, an increase of 8% compared to 2011.

Total production in 2013 is currently expected to average about 200,000 barrels of oil equivalent per day. The projected production increase of approximately 3% in 2013 includes a 17% increase in oil and liquids volumes, partially offset by a 16% decline in natural gas volumes. The overall increase is primarily related to higher oil production in the Eagle Ford Shale area as the Company continues its drilling program in the play. Additionally, Canadian oil production is expected to rise in 2013 at Seal where additional acreage was acquired in late 2012, and at the Terra Nova field, where a maintenance program led to significant field shut-in during the second half of 2012. These higher oil volumes are expected to more than offset production declines in 2013 at other producing fields. Natural gas production will fall in 2013 primarily due to a significant reduction in development drilling activities in the Tupper area in northeast British Columbia during this period of depressed North American natural gas prices.

United States

In the United States, Murphy primarily has production of oil and/or natural gas from fields in the deepwater Gulf of Mexico, in the Eagle Ford Shale area of South Texas and onshore in South Louisiana. The Company produced approximately 26,100 barrels of oil per day and 53 million cubic feet of natural gas per day in the U.S. in 2012. These amounts represented 23% of the Company's total worldwide oil and 11% of worldwide natural gas production volumes. During 2012, approximately 54% of total U.S. hydrocarbon production was produced at fields in the Gulf of Mexico. The largest of these fields in the Gulf of Mexico in 2012 were Medusa and Front Runner. The Company holds a 60% interest at Medusa in Mississippi Canyon Blocks 538/582, which produced total daily oil and natural gas of about 4,300 barrels and 4 MMCF, respectively, in 2012. Production from Medusa is expected to decline in 2013 and should average 3,300 barrels of oil and about 3 MMCF of natural gas on a daily basis. At December 31, 2012, the Medusa field had total proved oil and natural gas reserves of approximately 9.2 million barrels and 9.4 billion cubic feet, respectively. Murphy has a 62.5% working interest in the Front Runner field in Green Canyon Blocks 338/339. Oil and natural gas production at Front Runner averaged about 3,900 barrels of oil per day and 4 MMCF per day in 2012. Production in 2013 at Front Runner is expected to average approximately 6,000 barrels of oil per day and 4 MMCF per day. The higher 2013 production at Front Runner is primarily due to the acquisition of additional working interest in mid-2012. Proved oil and natural gas reserves at Front Runner at year-end 2012 were 11.2 million barrels and 12.2 billion cubic feet, respectively. The Company also acquired additional working interests in the Thunder Hawk field in Mississippi Canyon Block 734 in 2012 and now holds 62.5% of this field. In 2012 oil production from this field averaged 2,800 barrels per day and 1.7 MMCF per day and in 2013 is expected to average approximately 6,000 barrels oil per day and 3.2 MMCF per day due to a new well completed in late 2012 and the higher working interest.

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

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

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

Canada

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

Murphy has a 6.5% working interest in Hibernia, while at Terra Nova the Company's working interest is 10.475%. Oil production in 2012 was about 5,300 barrels of oil per day at Hibernia and 1,700 barrels per day at Terra Nova. Hibernia production decreased slightly in 2012 due to normal field decline, while Terra Nova experienced significant downtime for maintenance during the second half of 2012. Oil production for 2013 at Hibernia and Terra Nova is anticipated to be approximately 5,500 barrels per day and 4,000 barrels per day, respectively. Total proved oil reserves at December 31, 2012 at Hibernia and Terra Nova were approximately 10.6 million barrels and 5.9 million barrels, respectively. The joint agreement between owners of Terra Nova required a one-time redetermination of working interests based on an analysis of reservoir quality among fault separated areas where varying ownership interests exist. The redetermination process was essentially completed in 2010 and the Company's working interest was reduced from 12.0% to 10.475% effective January 1, 2011.

Murphy owns a 5% undivided interest in Syncrude Canada Ltd., a joint venture located about 25 miles north of Fort McMurray, Alberta. Syncrude utilizes its assets, which include three coking units, to extract bitumen from oil sand deposits and to upgrade this bitumen into a high-value synthetic crude oil. Production in 2012 was about 13,800 barrels of synthetic crude oil per day and is expected to average about 14,000 barrels per day in 2013. Total proved reserves for Syncrude at year-end 2012 were 119.1 million barrels.

Daily production in 2012 in the WCSB averaged about 7,500 barrels of mostly heavy oil and about 217 MMCF of natural gas. Through 2012, the Company has acquired approximately 144 thousand net acres of mineral rights in the Montney area, including Tupper and Tupper West. Natural gas production commenced at Tupper in December 2008, while Tupper West production started up in February 2011. Through 2012, the Company has acquired 316 thousand net acres of mineral rights in the Seal area located in the Peace River oil sands area of Northwest Alberta. The Company is also conducting other activities in the WCSB outside the Seal and Tupper areas. Through 2012, the Company has acquired approximately 151 thousand net acres of land in Southern Alberta that is prospective for light oil. The Company began drilling operations on this acreage in early 2011. Several wells were expensed as dry holes during 2011 and 2012. One well was on production test in 2012 and early 2013. Additional wells are planned in 2013 to test various formations within this acreage. Through 2012, the Company has acquired approximately 166 thousand net acres of land in Northwest Alberta that is prospective for light oil and liquids-rich natural gas. The Company began drilling operations on this acreage in 2012. One well was on production test in 2012. Additional wells are planned in 2013 to test various formations within this acreage. Oil and natural gas daily production for 2013 in Western Canada, excluding Syncrude, is expected to be about 10,900 barrels and 151 MMCF, respectively. The increase in oil production in 2013 is primarily due to an acquisition of additional acreage in the Seal heavy oil area in late 2012 and an ongoing drilling program for the Seal property. The decrease in natural gas volumes in 2013 is primarily due to a significant reduction in development drilling at Tupper West and Tupper associated with depressed North American natural gas prices. Natural gas prices in North America have continued to be weak in early 2013. Total Western Canada proved oil and natural gas reserves at December 31, 2012, excluding Syncrude, were 20.3 million barrels and 542.5 billion cubic feet, respectively.

Malaysia

In Malaysia, the Company has majority interests in six separate production sharing contracts (PSCs). The Company serves as the operator of all these areas other than the Kakap field. The production sharing contracts cover approximately 2.79 million gross acres. Murphy has an 85% interest in discoveries made in two shallow-water blocks, SK 309 and SK 311, offshore Sarawak. In January 2010, Murphy relinquished all other acreage in Blocks SK 309 and SK 311, while retaining the acreage surrounding its producing oil and gas fields as well as areas surrounding its other discoveries, where development projects are ongoing or planned in the future. At four of these discoveries, Serendah, Patricia, South Acis and Permas, production is scheduled to start up in the second half of 2013 through a series of new offshore platforms and pipelines tying back to the Company's existing West Patricia infrastructure. About 7,400 barrels of oil per day were produced in 2012 at Blocks SK 309/311, with almost 75% of this at the West Patricia field and the remainder mostly associated with gas liquids produced at other Sarawak fields. Oil production in 2013 at fields in Blocks SK 309/311 is anticipated to total about 8,500 barrels of oil per day, including the new fields mentioned above. The Company has a gas sales contract for the Sarawak area with PETRONAS, the Malaysian state-owned oil company, and has an ongoing multi-phase development plan for several natural gas discoveries on these blocks. Production from one of these discoveries, Belum, is scheduled to start in 2014. The gas sales contract allows for gross sales volumes of up to 250 MMCF per day through 2014, with an option to continue this production level for an additional seven years. In December 2012, Murphy exercised its option to extend the gas sales agreement, effectively lengthening Murphy's contract duration until September 2021. Total net natural gas sales volume offshore Sarawak was about 174 MMCF per day during 2012 (gross 243 MMCF per day). Sarawak net natural gas sales volumes are anticipated to be approximately 158 MMCF per day in 2013, with the reduction versus 2012 caused by higher planned downtime for maintenance and changes in entitlement in both blocks. Total proved reserves of oil and natural gas at December 31, 2012 for Blocks SK 309/311 were 10.3 million barrels and 284.7 billion cubic feet, respectively.

The Company made a major discovery at the Kikeh field in deepwater Block K, offshore Sabah, Malaysia, in 2002 and added another important discovery at Kakap in 2004. An additional discovery was made in Block K at Siakap. In 2006, the Company relinquished a portion of Block K and was granted a 60% interest in an extension of a portion of Block K. In 2011, the Company relinquished the remainder of Block K except for the discovered fields, which include Kikeh, Kakap and Siakap. Total gross acreage held by the Company in Block K as of December 31, 2012 was 80,000 acres. Production volumes at Kikeh averaged 44,900 barrels of oil per day during 2012. Kikeh oil production increased in 2012 compared to the prior year due to new wells brought on production in the second half of 2012. Oil production at Kikeh is anticipated to average approximately 40,500 barrels per day in 2013. In February 2007, the Company signed a Kikeh field natural gas sales contract with PETRONAS that calls for gross sales volumes of up to 120 MMCF per day through June 2012. Gas production at Kikeh is slated to continue after 2012 until the earlier of lack of available commercial quantities of Kikeh associated gas reserves or expiry of the Block K production sharing contract. Natural gas production at Kikeh began in late 2008, and 2012 production totaled approximately 42 MMCF per day in 2012. Daily gas production in 2013 at Kikeh is expected to average about 47 MMCF per day. The Kakap field in Block K is operated by another company. This field is being jointly developed with the Gumusut field owned by others and Murphy holds a 14% working interest in the unitized development. Kakap development activities continued during 2012 and early production occurred in late 2012, via a temporary tie-back to the Kikeh production facility. The primary Kakap production facility is expected to be completed in 2014, whereby oil production can be ramped up to a significantly higher volume. Kakap oil production in 2013 is anticipated to average 2,300 net barrels of oil per day. The Siakap oil discovery was made in 2009; the field will be a unitized development operated by Murphy. The field is presently under development as a tie-back to the Kikeh field and first oil production is currently anticipated in late 2013, with an average oil production volume of 1,000 barrels per day during the year. Associated gas produced at the Kakap and Siakap fields will be sold under separately negotiated contracts with PETRONAS. Total proved reserves booked in Block K as of year-end 2012 were 85.4 million barrels of oil and 72.9 billion cubic feet of natural gas.

The Company also has an interest in deepwater Block H offshore Sabah. In early 2007, the Company announced a significant natural gas discovery at the Rotan well in Block H. Since 2007, the Company has followed up Rotan with several other nearby discoveries. In March 2008, the Company renewed the contract for Block H at a 60% interest while retaining 80% interest in the Rotan and Biris discoveries. In 2011, the Company relinquished 30% of Block H, but retained all discovered fields. The Company is in the process of having unproved reserves certified by a third party reservoir engineering company. Total gross acreage held by the Company at year-end 2012 in Block H was 1.40 million acres. In early 2006, the Company added a 60% interest in a PSC covering Block P, which includes 1.05 million gross acres of the previously relinquished Block K area, offshore Sabah. To date, exploratory drilling in Block P has been unsuccessful. Block P was relinquished in January 2013 except for a gas holding area of approximately 2,000 gross acres surrounding the Rempah well which can be retained until January 2018.

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

Republic of the Congo

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

Australia

The Company holds six exploration permits in Australia and serves as operator of four of them. A number of exploration wells will be drilled on the permits between 2013 and 2015. A 40% interest in Block AC/P36 in the Browse Basin offshore northwestern Australia was acquired in 2007 and one unsuccessful well has been drilled. The Company renewed the exploration permit for an additional five years and in that process relinquished 50% of the gross acreage; the license now covers 482 thousand gross acres. Murphy increased its working interest in this block to 100% in 2012 and subsequently farmed out a 50% working interest and operatorship.
Block WA-423-P, also in the Browse Basin, was acquired in November 2008. The permit covers approximately 1.42 million gross acres with the Company holding a 40% working interest. The Company drilled an unsuccessful exploration well in late 2012 and anticipates relinquishing the entire permit in 2013. Block NT/P80 in the Bonaparte Basin, offshore northwestern Australia, was acquired in June 2009 and covers approximately 1.20 million gross acres. The Company will acquire 3D seismic data over this block on which its working interest has increased from 40% to 70%. In May 2012, Murphy was awarded permit WA-476-P in the Carnarvon Basin, offshore Western Australia. The Company holds 100% working interest in the permit which covers 177,000 gross acres. The work commitment includes seismic data reprocessing and geophysical work. In August 2012, Murphy was awarded permit WA-481-P in the Perth Basin, offshore Western Australia. The permit covers approximately 4.30 million gross acres, with water depths ranging from 20 to 300 meters. The Company holds a 40% working interest. The work commitment calls for 2D and 3D seismic acquisition and processing, geophysical work and three exploration wells. In November 2012, Murphy acquired a 20% non-operated working interest in permit WA-408-P in the Browse Basin. This block is adjacent to AC/P36 and is in the midst of a two-well exploration campaign. The permit comprises approximately 417,000 gross acres.

Indonesia

The Company currently has interests in four exploration licenses in Indonesia and serves as operator of all these concessions. In May 2008, the Company entered into a production sharing contract at a 100% interest, in the South Barito block in south Kalimantan on the island of Borneo. Following contractually mandated acreage relinquishment in 2012, the block now covers approximately 745 thousand gross acres. The contract permits a six-year exploration term with an optional four-year extension. The work commitment calls for geophysical work, 2D seismic acquisition and processing, and two exploration wells. In November 2008, Murphy entered into a production sharing contract in the Semai II block offshore West Papua. The Company has a 28.3% interest in the block which covers about 543 thousand gross acres after a required partial relinquishment of acreage during 2012. The permit calls for a 3D seismic program and three exploration wells. The 3D seismic was acquired in 2010, while the first exploration well in the Semai II block was drilled in early 2011 and was unsuccessful. Multiple additional drilling prospects are currently being evaluated. In December 2010, Murphy entered into a production sharing contract in the Wokam II block offshore West Papua, Moluccas and Papua. Murphy has a 100% interest in the block which covers 1.22 million gross acres. The three-year work commitment calls for seismic acquisition and processing, which the Company expects to begin in 2013. In November 2011, the Company acquired a 100% interest in a production sharing contract in the Semai IV block offshore West Papua. The concession includes 873 thousand gross acres. The agreement calls for work commitments of seismic acquisition and processing.

Brunei

In late 2010, the Company entered into two production sharing agreements for properties offshore Brunei. The Company has a 5% working interest in Block CA-1 and a 30% working interest in Block CA-2. The CA-1 and CA-2 blocks cover 1.44 million and 1.49 million gross acres, respectively. The first two exploration wells in Block CA-2 and the initial well in Block CA-1 were unsuccessful. Three successful wells were drilled in Block CA-1 in 2012. One exploratory well was drilling in Block CA-2 in early 2013 and an additional well is planned in the block later in the year.

Vietnam

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

In late 2012, the Company was granted Vietnam's government approval to acquire a 60% working interest and operatorship of Block 11-2/11. The Company is awaiting signing of this production sharing contract, which is expected in early 2013. The Company plans to make 3D seismic purchases and perform other geological and geophysical studies in this block in 2013.

Iraq

In late 2010, the Company finalized an agreement with the Kurdistan Regional Government (KRG) in Iraq to acquire an interest in the Central Dohuk block. The Company operates and holds a 50% interest in the block. The Central Dohuk block covers approximately 153 thousand gross acres and is located in the Dohuk area of the Kurdistan region in Iraq. The Company shot seismic in 2011 and drilled an unsuccessful exploration well in 2012. The Company's 20% non-operated interest in the Baranan block expired in 2012 and efforts to renew the license were unsuccessful.

Suriname

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

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

Cameroon

In October 2011, Murphy was granted government approval to acquire a 50% working interest and operatorship of the NTEM concession. The working interest was acquired from Sterling Cameroon Limited (Sterling) via a farm-out agreement of the existing production sharing contract. Sterling retained a 50% non-operated interest in the block. The NTEM block, situated in the Douala Basin offshore Cameroon, encompasses 573 thousand gross acres, with water depths ranging from 300 to 1,900 meters. The concession is currently in force majeure, pending the resolution of a border dispute with neighboring Equatorial Guinea. When force majeure is lifted, there will be 15 months of the first renewal period remaining which can be extended for a further two years under the second renewal period option in the contract. Each of the renewal periods requires a minimum work obligation involving the drilling of exploratory wells.

In October 2012, Murphy signed an agreement with Perenco Cameroon to acquire a 50% interest in the Elombo production sharing contract, immediately adjacent to the NTEM concession. The Company received government approval to acquire the acreage in December 2012. Perenco retained a 50% operating interest in the block. The Elombo block, situated in the Douala Basin offshore Cameroon, between the shoreline and the NTEM block, encompasses 594 thousand gross acres with water depths ranging up to 1,100 meters. The initial exploration period is for three years and commenced in March 2010. Prior to the end of the initial period the Company must drill a well, which is currently planned in early 2013. The initial exploration period may be extended two times for two years each, with a one well obligation for each extension. As "technical operator" for deepwater drilling, Murphy plans to drill a deepwater well in the block in 2013 as part of the obligations under the agreement.

Equatorial Guinea

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

United Kingdom – Discontinued Operations

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

Ecuador – Discontinued Operations

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

Proved Reserves

Total proved oil and natural gas reserves as of December 31, 2012 are presented in the following table.

	Proved Reserves		
	Oil	Synthetic Oil	Natural Gas
	(millions of barrels)		(billions of cubic feet)
Proved Developed Reserves:			
United States	48.0	–	78.8
Canada	29.5	119.1	415.8
Malaysia	67.0	–	197.3
Republic of the Congo	–	–	–
United Kingdom – discontinued operations	4.1	–	14.1
Total proved developed reserves	148.6	119.1	706.0
Proved Undeveloped Reserves:			
United States	94.6	–	130.9
Canada	7.3	–	134.6
Malaysia	28.7	–	160.3
Republic of the Congo	–	–	–
United Kingdom – discontinued operations	16.5	–	5.2
Total proved undeveloped reserves	147.1	–	431.0
Total proved reserves	295.7	119.1	1,137.0

Murphy's total proved undeveloped reserves at December 31, 2012 increased 42.0 million barrels of oil equivalent (MMBOE) from a year earlier. Approximately 44.0 MMBOE of proved undeveloped reserves were converted to proved developed reserves during 2012. The majority of the proved undeveloped reserves migration to the proved developed category occurred at the Tupper, Tupper West and Eagle Ford Shale areas, as these areas had active development work ongoing during the year. The conversion of non-proved reserves to newly reported proved undeveloped reserves occurred at several areas including, but not limited to, the Tupper, Tupper West and Eagle Ford Shale areas and the Kikeh field. During 2012, there were 26.6 MMBOE of positive revisions for proved undeveloped reserves. The majority of proved undeveloped reserves additions associated with revisions of previous estimates were the result of development drilling and well performance at the Kikeh field in Malaysia and the Eagle Ford Shale in South Texas. The Company spent approximately $2.2 billion in 2012 to convert proved undeveloped reserves to proved developed reserves. The Company expects to spend about $2.2 billion in 2013, $1.9 billion in 2014 and $1.5 billion in 2015 to move currently undeveloped proved reserves to the developed category. The anticipated level of spend in 2013 includes significant drilling in several locations, including the Kikeh field and the Eagle Ford Shale area. In computing MMBOE, natural gas is converted to equivalent barrels of oil using a ratio of six thousand cubic feet (MCF) to one barrel of oil.

At December 31, 2012, proved reserves are included for several development projects that are ongoing, including natural gas developments at the Tupper West area in British Columbia and offshore Sarawak Malaysia, and an oil development at Kakap, offshore Sabah Malaysia. Total proved undeveloped reserves associated with various development projects at December 31, 2012 were approximately 219 MMBOE, which is 36% of the Company's total proved reserves. Certain of these development projects have proved undeveloped reserves that will take more than five years to bring to production. Three such projects have significant levels of such proved undeveloped reserves. The Company operates a deepwater field in the Gulf of Mexico that has two undeveloped locations that exceed this five-year window. Total reserves associated with the two wells amount to less than 1% of the Company's total proved reserves at year-end 2012. The development of certain of this field's reserves stretches beyond five years due to limited well slots available on the production platform, thus making it necessary to wait for depletion of other wells prior to initiating further development of these two locations. The

Kakap field oil development project has undeveloped proved reserves that make up less than 3% of the Company's total proved reserves at year-end 2012. This non-operated project will take longer than five years to develop due to long lead-time equipment required to complete the development process in the deep waters offshore Sabah Malaysia. The third project that will take more than five years to develop is offshore Malaysia and makes up approximately 3% of the Company's total proved reserves at year-end 2012. This project is an extension of the Sarawak natural gas project and should be on production in 2014 once current project production volumes decline.

Murphy Oil's Reserves Processes and Policies

The Company employs a Manager of Corporate Reserves (Manager) who is independent of the Company's oil and gas management. The Manager reports to an Executive Vice President of Murphy Oil Corporation, who in turn reports directly to the President and Chief Executive Officer of Murphy Oil. The Manager makes presentations to the Board of Directors periodically about the Company's reserves. The Manager reviews and discusses reserves estimates directly with the Company's reservoir engineering staff in order to make every effort to ensure compliance with the rules and regulations of the SEC and industry. The Manager coordinates and oversees reserves audits. These audits are performed annually and target coverage of approximately one-third of Company reserves each year. The audits are performed by the Manager and qualified engineering staff from areas of the Company other than the area being audited. The Manager may also utilize qualified independent reserves consultants to assist with the internal audits or to perform separate audits as considered appropriate. The Company may also use independent reserves consultants to determine a portion of its proved reserves reported in this Form 10-K. At December 31, 2012, the Company used McDaniel & Associates Consultants Ltd., an independent petroleum engineering company, to prepare estimated proved oil reserves for its synthetic oil operations, which represented 29% of Murphy's total oil proved reserves. At December 31, 2012 and 2011, the Company utilized Ryder Scott Company, L.P., an independent petroleum engineering company, to prepare estimated proved oil and natural gas reserves for certain geographic areas. The total estimated proved reserves at December 31, 2012 prepared by Ryder Scott represented 4% and 1% of the Company's total proved oil and proved natural gas reserves, respectively, while at December 31, 2011, these amounts for proved oil and proved natural gas reserves were 16% and 5%, respectively. McDaniel & Associates' and Ryder Scott's reports are included as Exhibits 99.9 through 99.11 to this Annual Report on Form 10-K.

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

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

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

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

Qualifications of Manager of Corporate Reserves

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

More information regarding Murphy's estimated quantities of proved oil and gas reserves for the last three years are presented by geographic area on pages F-48 and F-49 of this Form 10-K report. Murphy has not filed and is not required to file any estimates of its total proved oil or gas reserves on a recurring basis with any federal or foreign governmental regulatory authority or agency other than the U.S. Securities and Exchange Commission. Annually, Murphy reports gross reserves of properties operated in the United States to the U.S. Department of Energy; such reserves are derived from the same data from which estimated proved reserves of such properties are determined.

Crude oil, condensate and gas liquids production and sales, and natural gas sales by geographic area with weighted average sales prices for each of the seven years ended December 31, 2012 are shown on page 5 of the 2012 Annual Report. In 2012, the Company's production of oil and natural gas represented approximately 0.1% of worldwide totals.

Production expenses for the last three years in U.S. dollars per equivalent barrel are discussed beginning on page 35 of this Form 10-K report. For purposes of these computations, natural gas sales volumes are converted to equivalent barrels of oil using a ratio of six MCF of natural gas to one barrel of oil.

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

At December 31, 2012, Murphy held leases, concessions, contracts or permits on developed and undeveloped acreage as shown by geographic area in the following table. Gross acres are those in which all or part of the working interest is owned by Murphy. Net acres are the portions of the gross acres attributable to Murphy's interest.

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

Certain acreage held by the Company will expire in the next three years. Scheduled expirations in 2013 include 36 thousand net acres in Block PM 311 in Malaysia; 626 thousand net acres in Block P Malaysia; 306 thousand net acres in Wokam II Indonesia; 323 thousand net acres consisting of Block MPS other than the Azurite field, offshore Republic of the Congo; 119 thousand net acres in the United States; 51 thousand net acres in Western Canada; and 19 thousand net acres in the Kurdistan region of Iraq. In 2014, 497 thousand net acres expire in South Barito Indonesia; 106 thousand net acres expire in Semai II Indonesia; 218 thousand net acres expire in Semai IV Indonesia; 569 thousand net acres expire in WA-423-P Australia; 179 thousand net acres expire in the United States; and 39 thousand net acres expire in Western Canada. In 2015, scheduled expiring acreage includes 67 thousand net acres in SK Blocks 309 and 311 in Malaysia; 420 thousand net acres in NT/P80 Australia; 42 thousand net acres in WA-408-P Australia; 57 thousand net acres in the Kurdistan region of Iraq; 280 thousand net acres in Western Canada; and 59 thousand net acres in the United States.

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

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

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

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

	United States		Canada		Malaysia		United Kingdom		Other		Totals	
	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry
2012												
Exploratory	**15.2**	**0.1**	**–**	**1.0**	**2.8**	**0.8**	**–**	**–**	**–**	**2.9**	**18.0**	**4.8**
Development	**92.2**	**–**	**106.5**	**21.5**	**20.5**	**–**	**–**	**–**	**–**	**–**	**219.2**	**21.5**
2011												
Exploratory	17.9	–	1.0	4.9	0.9	–	–	–	–	2.3	19.8	7.2
Development	14.3	0.8	117.5	6.0	12.8	–	–	–	0.5	–	145.1	6.8
2010												
Exploratory	9.2	–	–	–	6.8	0.8	–	0.1	1.0	2.5	17.0	3.4
Development	–	–	87.0	5.0	23.6	–	–	–	2.5	–	113.1	5.0

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

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

Refining and Marketing

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

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

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

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

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

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

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

The Company owns land underlying 908 of the Company stations on Walmart parking lots. No rent is payable to Walmart for the owned locations. For the remaining 104 Company stations located on Walmart property that are not owned, Murphy has master agreements that allow the Company to rent land from Walmart. The master agreements contain general terms applicable to all rental sites on Walmart property in the United States. The terms of the agreements range from 10-15 years at each station, with Murphy holding two successive five-year extension options at each site. The agreements permit Walmart to terminate the agreements in their entirety, or only as to affected sites, at its option for the following reasons: Murphy vacates or abandons the property; Murphy improperly transfers the rights under this agreement to another party; an agreement or a premises is taken upon execution or by process of law; Murphy files a petition in bankruptcy or becomes insolvent; Murphy fails to pay its debts as they become due; Murphy fails to pay rent or other sums required to be paid within 90 days after written notice; or Murphy fails to perform in any material way as required by the agreements. The Company also has three Murphy USA locations located near Walmart locations that are leased from other landowners. Of the 150 Murphy Express stations, 145 are on land owned by Murphy and five are leased properties.

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

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

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

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

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

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

Murco Petroleum Limited (Murco), a wholly owned U.K. subsidiary, owns 100% interest in a refinery at Milford Haven, Pembrokeshire, Wales. The refinery is located on a 938 acre site owned by the Company; 430 acres are used by the refinery and the remainder is rented for agricultural use. The Milford Haven refinery was shut down for a plant-wide turnaround in early 2010. During the downtime, the Company completed an expansion project that increased the plant's crude oil throughput capacity from 108,000 barrels per day to 135,000 barrels per day. The refinery consistently performed near nameplate capacity during 2012. Murphy has announced its intention to sell the Milford Haven refinery and U.K. marketing assets.

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

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

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

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

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

Environmental

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

Further information on environmental matters and their impact on Murphy are contained in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 45 through 49.

Web site Access to SEC Reports

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

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

Item 1A. RISK FACTORS

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

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

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

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

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

Proved oil and natural gas reserves included in this report on pages F-48 and F-49 have been prepared by qualified Company personnel or qualified independent engineers based on an unweighted average of oil and natural gas prices in effect at the beginning of each month during the years 2010 through 2012 as well as other conditions and information available at the time the estimates were prepared. Estimation of reserves is a subjective process that involves professional judgment by engineers about volumes to be recovered in future periods from underground crude oil and natural gas reservoirs. Estimates of economically recoverable crude oil and natural gas reserves and future net cash flows depend upon a number of variable factors and assumptions, and consequently, different engineers could arrive at different estimates of reserves and future net cash flows based on the same available data and using industry accepted engineering practices and scientific methods. Under existing SEC rules, reported proved reserves must be reasonably certain of recovery in future periods.

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

- Oil and natural gas prices which are materially different than prices used to compute proved reserves
- Operating and/or capital costs which are materially different than those assumed to compute proved reserves
- Future reservoir performance which is materially different from models used to compute proved reserves, and
- Governmental regulations or actions which materially change operations of a field.

The Company's proved undeveloped reserves represent significant portions of total proved reserves. As of December 31, 2012, approximately 35% of the Company's proved oil reserves and 38% of proved natural gas reserves are undeveloped. The ability of the Company to reclassify these undeveloped proved reserves to the proved developed classification is generally dependent on the successful completion of one or more operations, which might include further development drilling, construction of facilities or pipelines, and well workovers.

The discounted future net revenues from our proved reserves as reported on page F-53 should not be considered as the market value of the reserves attributable to our properties. As required by generally accepted accounting principles, the estimated discounted future net revenues from our proved reserves are based on an unweighted average of the oil and natural gas prices in effect at the beginning of each month during the year. Actual future prices and costs may be materially higher or lower than those used in the reserves computations. In addition, the 10 percent discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under generally accepted accounting principles is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the crude oil and natural gas business in general.

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

Among the most significant variables affecting the Company's results of operations are the sales prices for crude oil and natural gas that it produces. West Texas Intermediate (WTI) crude oil prices averaged about $94 per barrel in 2012, compared to $95 per barrel in 2011 and $80 per barrel in 2010. As an example of the impacts that oil and gas prices have on the Company's results of operations, the significant increase in oil prices in 2011 compared to the prior year favorably impacted earnings for the exploration and production business in that year. The average NYMEX natural gas sales prices were $2.83 per thousand cubic feet (MCF) in 2012, down from $4.03 per MCF in 2011 and $4.38 per MCF in 2010. This lower price for natural gas hurt the Company's profits in North America in 2012. The Company's net income is also significantly affected by changes in the margins on refining and marketing operations. As demonstrated in 2012 and 2011, the sales prices for oil and natural gas can be significantly different in U.S. markets compared to markets in foreign locations. Certain of the Company's crude oil production is heavy and more sour than WTI quality crude; therefore, this crude oil usually sells at a discount to WTI and other light and sweet crude oils. In addition, the sales prices for heavy and sour crude oils do not always move in relation to price changes for WTI and lighter/sweeter crude oils. Certain crude oils produced outside North America generally price off different oil indices (Malaysia – Kikeh or Tapis and U.K. – Brent), and these indices are influenced by different supply and demand forces than those that affect the U.S. WTI prices. Certain natural gas production, particularly in Sarawak Malaysia and the U.K., have been sold in recent years at a premium to average North American natural gas prices due to different pricing structures for gas in these regions. The Company cannot predict how changes in the sales prices of oil and natural gas and changes in refining and marketing margins will affect its results of operations in future periods. Except in limited cases, the Company typically does not seek to hedge any significant portion of its exposure to the effects of changing prices of crude oil, natural gas and refined products.

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

The Company generally drills numerous wildcat wells each year which subjects its exploration and production operating results to significant exposure to dry holes expense, which have adverse effects on, and create volatility for, the Company's net income. In 2012, significant wildcat wells were primarily drilled offshore Republic of the Congo, Malaysia, Brunei and Australia, and onshore in Kurdistan. The Company's 2013 planned exploratory drilling program includes wells offshore in the Gulf of Mexico, Cameroon, Brunei, Australia, Malaysia and Indonesia, and onshore in Western Canada.

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

Murphy usually must spend and risk a significant amount of capital to find and develop reserves before revenue is generated from production. Although most capital needs are funded from operating cash flow, the timing of cash flows from operations and capital funding needs may not always coincide, and the levels of cash flow may not fully cover capital funding requirements. Therefore, the Company maintains financing arrangements with lending institutions to meet certain funding needs. The Company must periodically renew these financing arrangements based on foreseeable financing needs or as they expire. The Company's primary bank financing facility was renewed in 2011 and now expires in June 2016. Although not considered likely, there is the possibility that financing arrangements may not always be available at sufficient levels required to fund the Company's activities in future periods. The Company has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities through October 2015. Outstanding notes of $350 million matured in May 2012 and were replaced with $500 million of notes that mature in May 2022. Additionally, in November 2012, the Company sold $1.5 billion of notes that mature between 2017 and 2042. Although not considered likely, the Company may not be able in the future to sell notes at reasonable rates in the marketplace.

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

The ability of the Company to successfully manage development and operating costs is important because virtually all of the products it sells are energy commodities such as crude oil, natural gas and refined products, for which the Company has little or no influence on the sales prices or regional and worldwide consumer demand for these products. As an example, an economic slowdown in 2009 had a detrimental effect on the worldwide demand for these energy commodities, which effectively led to reduced prices for oil, natural gas and refined products for a period of time. Lower prices for crude oil and natural gas inevitably lead to lower earnings in the Company's exploration and production operations. Murphy is a net purchaser of crude oil and other refinery feedstocks in the U.K., and also purchases refined products, particularly gasoline, needed to supply its U.S. retail marketing stations. Therefore, its most significant costs are subject to volatility of prices for these commodities. The Company also often experiences pressure on its operating and capital expenditures in periods of strong crude oil, natural gas and refined product prices because an increase in exploration and production activities due to high oil and gas sales prices generally leads to higher demand for, and consequently higher costs for, goods and services in the oil and gas industry.

Many of the Company's major oil and natural gas producing properties are operated by others. Therefore, Murphy does not fully control all activities at certain of its significant revenue generating properties. During 2012, approximately 17% of the Company's total production was at fields operated by others, while at December 31, 2012, approximately 31% of the Company's total proved reserves were at fields operated by others.

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

Many governments, including those that are members of the Organization of Petroleum Exporting Countries (OPEC), unilaterally intervene at times in the orderly market of crude oil and natural gas produced in their countries through such actions as setting prices, determining rates of production, and controlling who may buy and sell the production. As of December 31, 2012, approximately 26% of proved reserves, as defined by the U.S. Securities and Exchange Commission, were located in countries other than the U.S., Canada and the U.K. Certain of the reserves held outside these three countries could be considered to have more political risk. In addition, prices and availability of crude oil, natural gas and refined products could be influenced by political unrest and by various governmental policies to restrict or increase petroleum usage and supply. Other governmental actions that could affect Murphy's operations and earnings include expropriation, tax changes, royalty increases, redefinition of international boundaries and regulations concerning: currency fluctuations, protection and remediation of the environment, concerns over the possibility of global warming being affected by human activity including the production and use of hydrocarbon energy, preferential and discriminatory awarding of oil and gas leases, restrictions on drilling and/or production, restraints and controls on imports and exports, safety, and relationships between employers and employees. Additionally, because of the numerous countries in which the Company operates, certain other risks exist, including the application of the U.S. Foreign Corrupt Practices Act, the U.K. Bribery Act, and similar anti-corruption compliance statutes. Because these and other factors too numerous to list are subject to changes caused by governmental and political considerations and are often made in response to changing internal and worldwide economic conditions and to actions of other governments or specific events, it is not practical to attempt to predict the effects of such factors on Murphy's future operations and earnings.

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

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

In April 2010, a drilling accident and subsequent oil spill occurred in the Gulf of Mexico at the Macondo well owned by other companies. Impacts of the accident and oil spill include added delays in deepwater Gulf of Mexico drilling activities, additional regulations covering offshore drilling operations, and expected higher costs for future drilling operations and offshore insurance. Additional regulations, possible permitting delays and other restrictions associated with drilling and similar operations in the Gulf of Mexico are expected to have an adverse affect on the Company's, and likely many other companies', volume and costs of oil and natural gas produced in this area.

The location of many of Murphy's key assets causes the Company to be vulnerable to severe weather, including hurricanes and tropical storms. A number of significant oil and natural gas fields lie in offshore waters around the world. Probably the most vulnerable of the Company's offshore fields are in the U.S. Gulf of Mexico, where severe hurricanes and tropical storms have often led to shutdowns and damages. The U.S. hurricane season runs from June through November, but the most severe storm activities usually occur in late summer, such as with Hurricanes Katrina and Rita in 2005. Other assets such as gasoline terminals and certain retail gasoline stations also lie near the Gulf of Mexico coastline and are vulnerable to storm damages. Although the Company maintains insurance for such risks as described below, due to policy deductibles and possible coverage limits, weather-related risks are not fully insured.

Murphy may be unable to complete its announced reorganization plan.

The Company has announced a series of transactions, including the intended sale of its U.K. downstream business, separation of its U.S. downstream company, and up to a $1 billion share buyback program. Factors that could cause one or more of these events not to occur include, but are not limited to, a failure to obtain necessary regulatory approvals, a failure to obtain assurances of anticipated tax treatment, a deterioration in the business or prospects of Murphy or its subsidiaries, adverse developments in Murphy or its subsidiaries' markets, adverse developments in the U.S. or global capital markets, credit markets or economies generally or a failure to execute a sale of the U.K. downstream operations on acceptable terms.

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

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

Murphy's U.K. downstream operations is completed, the Company will no longer have the income generated from these assets to service its debt. If Murphy's remaining business is not successful as a stand-alone company, the Company may not have sufficient income to make interest payments on outstanding notes, repay the notes at maturity or refinance the notes on acceptable terms, if at all.

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

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

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

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

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

Although Murphy limits its credit risk by selling its products to numerous entities worldwide, it still, at times, carries substantial credit risk from its customers. For certain oil and gas properties operated by the Company, other companies which own partial interests may not be able to meet their financial obligation to pay for their share of capital and operating costs as they come due.

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

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

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

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

Item 1B. UNRESOLVED STAFF COMMENTS

The Company had no unresolved comments from the staff of the U.S. Securities and Exchange Commission as of December 31, 2012.

Item 2. PROPERTIES

Descriptions of the Company's oil and natural gas and refining and marketing properties are included in Item 1 of this Form 10-K report beginning on page 1. Information required by the Securities Exchange Act Industry Guide No. 2 can be found in the Supplemental Oil and Gas Information section of this Annual Report on Form 10-K on pages F-46 to F-54 and in Note D – Property, Plant and Equipment beginning on page F-15.

Executive Officers of the Registrant

The age at January 1, 2013, present corporate office and length of service in office of each of the Company's executive officers are reported in the following listing. Executive officers are elected annually but may be removed from office at any time by the Board of Directors.

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

Roger W. Jenkins – Age 51; Chief Operating Officer since June 2012. Mr. Jenkins has been Executive Vice President Exploration and Production since August 2009 and has served as President of the Company's exploration and production subsidiary since January 2009. He was Senior Vice President, North America for this subsidiary from September 2007 to December 2008, and prior to that time, held various positions, including General Manager of the Company's exploration and production operations in Sabah, Malaysia.

Kevin G. Fitzgerald – Age 57; Executive Vice President and Chief Financial Officer since December 2011. Mr. Fitzgerald was Senior Vice President and CFO from January 2007 to November 2011. He served as Treasurer from July 2001 through December 2006.

Thomas McKinlay – Age 49; Executive Vice President, U.K. Downstream since January 2013. Mr. McKinlay was Executive Vice President, Worldwide Downstream from January 2011 to January 2013 and Vice President, U.S. Manufacturing from August 2009 to January 2011. Mr. McKinlay was President of the Company's U.S. refining and marketing subsidiary from January 2011 to January 2013, and was Vice President, Supply and Transportation of this subsidiary from April 2009 to January 2011. From August 2008 to March 2009, Mr. McKinlay was General Manager, Supply and Transportation of this U.S. subsidiary, and from January 2007 to August 2008 was Supply Director for the Company's U.K. refining and marketing subsidiary.

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

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

John W. Eckart – Age 54; Senior Vice President and Controller since December 2011. Mr. Eckart was Vice President and Controller from January 2007 to November 2011, and has served as Controller since March 2000.

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

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

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

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

Item 3. LEGAL PROCEEDINGS

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

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

The Company's Common Stock is traded on the New York Stock Exchange using "MUR" as the trading symbol. There were 2,361 stockholders of record as of December 31, 2012. Information as to high and low market prices per share and dividends per share by quarter for 2012 and 2011 are reported on page F-55 of this Form 10-K report.

Murphy Oil Corporation
Issuer Purchases of Equity Securities

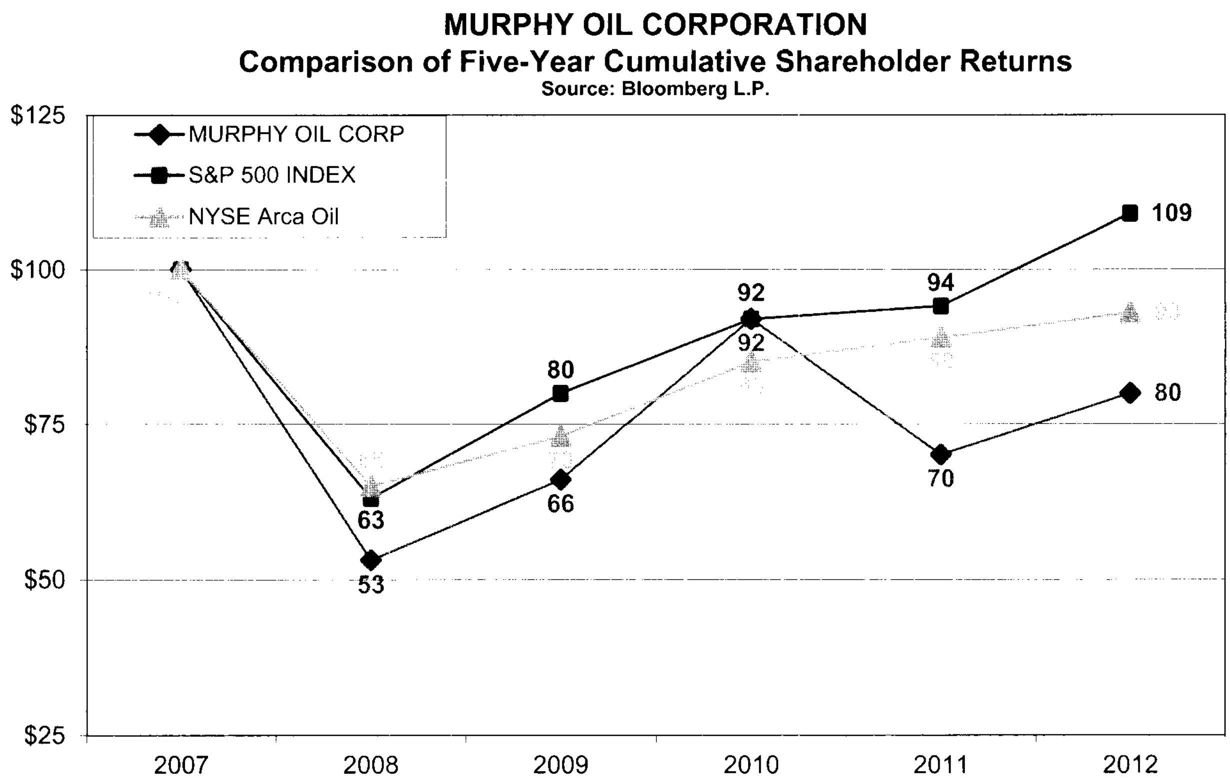
Period	Total Number of Shares Purchased[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[1]
October 1, 2012 to October 31, 2012	–	–	–	–
November 1, 2012 to November 30, 2012	–	–	–	–
December 1, 2012 to December 31, 2012	3,867,550	$64.64[2]	3,867,550	$750,000,000
Total October 1, 2012 to December 31, 2012	**3,867,550**	**$64.64**	**3,867,550**	**$750,000,000**

1 On October 16, 2012, the Company announced that its Board of Directors had authorized a buyback of up to $1.0 billion of the Company's Common stock. On December 10, 2012, the Company announced that it had entered into a variable term, capped accelerated share repurchase transaction (ASR) with a major financial institution to repurchase an aggregate of $250 million of the Company's Common stock. The total aggregate number of shares repurchased pursuant to this ASR will be determined by reference to the Rule 10b-18 volume-weighted price of the Company's Common stock, less a fixed discount, over the term of the ASR, subject to a minimum number of shares. The ASR is expected to be completed no later than May 2013. Through December 31, 2012, the minimum amount of Common stock totaling 3,867,550 shares had been delivered to the Company pursuant to the ASR. Any remaining shares will be delivered to the Company upon the completion of the ASR program.

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

SHAREHOLDER RETURN PERFORMANCE PRESENTATION

The following graph presents a comparison of cumulative five-year shareholder returns (including the reinvestment of dividends) as if a $100 investment was made on December 31, 2007 for the Company, the Standard & Poor's 500 Stock Index (S&P 500 Index) and the NYSE ARCA Oil Index. This performance information is "furnished" by the Company and is not considered as "filed" with this Form 10-K and it is not incorporated into any document that incorporates this Form 10-K by reference.



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

Item 6. SELECTED FINANCIAL DATA

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

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

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

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

- Percentage return on average stockholders' equity – net income for the year (as per the consolidated statement of income) divided by a 12-month average for January to December of total stockholders' equity.
- Percentage return on average borrowed and invested capital – the sum of net income for the year (as per the consolidated statement of income) plus after-tax interest expense for the year divided by a 12-month average for January to December of the sum of total long-term debt plus total stockholders' equity.
- Percentage return on average total assets – net income for the year (as per the consolidated statement of income) divided by a 12-month average for January to December of total consolidated assets.
- Long-term debt – percent of capital employed – total long-term debt at the balance sheet date (as per the consolidated balance sheet) divided by the sum of total long-term debt plus total stockholders' equity at that date (as per the consolidated balance sheet).

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

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

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

Murphy Oil Corporation is a worldwide oil and gas exploration and production company with petroleum marketing operations in the United States and refining and marketing operations in the United Kingdom. A more detailed description of the Company's significant assets can be found in Item 1 of this Form 10-K report.

Murphy generates revenue by selling oil and natural gas production to customers in the United States, Canada, Malaysia and other countries. Additionally, the Company generates revenue by selling refined petroleum and ethanol products at hundreds of locations in the United States and the United Kingdom. The Company's revenue is highly affected by the prices of oil, natural gas and refined petroleum products that it sells. Also, because crude oil is purchased by the Company for U.K. refinery feedstocks, natural gas is purchased for fuel at its U.K. refinery, U.S. ethanol plants and at worldwide oil production facilities, and gasoline is purchased to supply its retail gasoline stations in the U.S. that are primarily located at Walmart Supercenters, the purchase prices for these commodities also have a significant effect on the Company's costs. In order to make a profit and generate cash in its exploration and production business, revenue generated from the sales of oil and natural gas produced must exceed the combined costs of producing these products, amortization of capital expenditures and expenses related to exploration and administration. Profits and generation of cash in the Company's refining and marketing operations are dependent upon achieving adequate margins, which are determined by the sales prices for refined petroleum products less the costs of purchased refinery feedstocks and gasoline and expenses associated with manufacturing, transporting and marketing these products. Murphy also incurs certain costs for general company administration and for capital borrowed from lending institutions and note holders.

Changes in the price of crude oil and natural gas have a significant impact on the profitability of the Company, especially the price of crude oil as oil represented approximately 58% of the total hydrocarbons produced on an energy equivalent basis (one barrel of crude oil equals six thousand cubic feet of natural gas) by the Company in 2012. In 2013, the Company's ratio of hydrocarbon production represented by oil is expected to be approximately two-thirds oil, one-third gas, due to a combination of growing oil production and declining North American natural gas production. If the prices for crude oil and natural gas should weaken in 2013 or beyond, the Company would expect this to have an unfavorable impact on operating profits for its exploration and production business. Such lower oil and gas prices could, but may not, have a favorable impact on the Company's refining and marketing operating profits.

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

Results of Operations

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

(Millions of dollars, except EPS)	Years Ended December 31		
	2012	2011	2010
Net income	**$970.9**	872.7	798.1
Diluted EPS	**4.99**	4.49	4.13
Income from continuing operations	**$964.1**	729.5	749.1
Diluted EPS	**4.95**	3.75	3.88
Income from discontinued operations	**$ 6.8**	143.2	49.0
Diluted EPS	**0.04**	0.74	0.25

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

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

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

2012 vs. 2011 – Net income in 2012 was $970.9 million ($4.99 per diluted share) compared to $872.7 million ($4.49 per diluted share) in 2011. Income from continuing operations was $964.1 million ($4.95 per diluted share) in 2012, up from $729.5 million ($3.75 per diluted share) in 2011. Earnings for 2012 increased primarily due to a combination of lower impairment charges, income tax benefits, higher crude oil sales volumes, lower exploration expenses and higher U.K. R&M earnings. These were partially offset by lower North American natural gas sales prices, lower U.S. retail marketing margins, and unfavorable effects of foreign exchange compared to the prior year. Net income in 2012 and 2011 included income from discontinued operations of $6.8 million ($0.04 per diluted share) and $143.2 million ($0.74 per diluted share), respectively. The stronger results for discontinued operations in 2011 were primarily associated with operating income and a net gain on disposal of two U.S. refineries (Meraux, Louisiana and Superior, Wisconsin) and associated marketing assets which were sold in 2011.

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

Sales and other operating revenues grew $1.0 billion in 2012 compared to 2011 due to higher crude oil sales volumes for the E&P business, plus slightly larger sales volumes for both the U.S. and U.K. R&M continuing operations. Gain (loss) on sale of assets was $23.9 million less in 2012 than 2011 because the earlier year included a $23.1 million gain on sale of natural gas storage assets in Spain. Interest and other operating income was unfavorable by $22.0 million in 2012 compared to 2011 mostly due to an $18.4 million unfavorable pretax variance from the effects of transactions denominated in foreign currencies, plus interest income in 2011 of $2.7 million associated with a recovery of Federal royalties for certain deepwater Gulf of Mexico fields. The expense associated with crude oil and product purchases increased by $574.0 million in 2012 compared to 2011 primarily due to higher costs for wholesale gasoline and other motor fuels which were purchased for resale at the Company's retail fueling stations in the U.S. and U.K. Operating expenses were $162.6 million more in 2012 than 2011 due to a combination of higher oil and natural gas production costs and higher costs for U.S. retail gasoline station operations. Exploration expenses were $108.4 million lower in 2012 compared to 2011 due to more drilling success in 2012, plus lower geophysical expense in the Gulf of Mexico, Malaysia, Brunei and the Kurdistan region of Iraq. Selling and general expenses were $57.0 million more in 2012 than in 2011 primarily due to higher employee compensation and professional services costs. Depreciation, depletion and amortization expense rose $295.8 million in 2012 versus 2011 due to higher crude oil and natural gas sales volumes in 2012 and higher E&P per-unit depreciation rates. Impairment of properties was $107.6 million lower in 2012 than in 2011, primarily due to a smaller impairment charge in Republic of the Congo in 2012, partially offset by a writedown in the current year of the Hereford, Texas, ethanol production facility. Accretion of asset retirement obligations was $4.6 million more in 2012 than 2011 primarily due to higher discounted abandonment liabilities for wells drilled in 2012 in Malaysia, higher estimated abandonment costs for wells in the Gulf of Mexico, and higher future reclamation costs for synthetic oil operations at Syncrude. Redetermination of working interest at the Terra Nova field was a $5.4 million benefit in 2011 due to nonrecurring income achieved upon final settlement of the redetermination process in early 2011. Interest expense in 2012 was $1.7 million less than 2011 primarily due to lower average interest rates paid on borrowed funds in the later year, partially offset by the effects of higher average outstanding debt levels in the most recent year. The benefit from capitalized interest was $24.0 million higher in 2012 than the prior year due to larger levels of financing costs allocated to ongoing oil development projects in the later year. Income tax expense in 2012 was $104.2 million less than 2011 primarily due to U.S. income tax benefits of $108.3 million in 2012 associated with exploration activities in Republic of the Congo and Suriname. The consolidated effective tax rate was 40.6% in 2012 compared to 51.1% in 2011, with the lower rate in the later year caused by the U.S. tax benefits for Republic of the Congo and Suriname, a lower percentage of earnings in higher tax jurisdictions in 2012, and lower current year exploration and other expenses in foreign jurisdictions where no income tax benefit can presently be recognized due to no assurance that these expenses will be realized in 2012 or future years to reduce taxes owed. The tax rates in both 2012 and 2011 were higher than the U.S. federal statutory tax rate of 35.0% due to a combination of U.S. state income taxes, certain foreign tax rates that exceeded the U.S. federal tax rate, and certain exploration and other expenses in foreign taxing jurisdictions for which no income tax benefit is currently being recognized because of the Company's uncertain ability to obtain tax benefits for these costs in 2012 or future years. Income from discontinued operations was $6.8 million ($0.04 per diluted share) in 2012 and $143.2 million ($0.74 per diluted share) in 2011. Income from discontinued operations in both years included operating results for oil and gas production operations in the U.K., but discontinued operations in 2011 included operating profits of $113.1 million associated with the two U.S. petroleum refineries sold in late 2011, plus an $18.7 million after-tax gain on sale of these refineries.

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

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

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

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

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

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

Income for E&P continuing operations in 2012 was $290.8 million more than in 2011. The increase was primarily attributable to lower impairment charges of $168.6 million in Republic of the Congo in 2012, favorable tax benefits of $108.3 million in the current year for exploration activities in Republic of the Congo and Suriname, plus higher crude oil and natural gas sales volumes and stronger crude oil sales prices in the current year. The Company's average realized sales price for crude oil, condensate and gas liquids in 2012 for continuing operations increased $1.40 per barrel over 2011. The Company's average natural gas sales prices in Sarawak Malaysia were also higher in 2012 than 2011, but natural gas sales prices in 2012 in North America were significantly below 2011 levels. Crude oil and liquids sales volumes increased 12% in 2012 while natural gas sales volumes rose 7%. The increase in hydrocarbon sales volumes in 2012 led to higher expenses for production and depreciation of $104.5 million and $288.4 million, respectively. The 2012 year had less exploration expenses of $108.5 million compared to 2011, essentially due to lower expenses related to unsuccessful exploratory drilling and geophysical activities. Crude oil sales volumes increased in 2012 in the U.S. primarily due to higher volumes produced in the Eagle Ford Shale area of South Texas. Conventional oil sales volumes in Canada in 2012 were less than 2011 primarily due to lower gross production at the Terra Nova field, where more downtime for maintenance occurred in the current year. Synthetic oil sales volumes at Syncrude increased in 2012 due to higher gross production compared to 2011. Sales volumes for crude oil produced in Malaysia were higher in

2012 primarily due to new wells brought on production at the Kikeh field offshore Sabah. Crude oil sales volumes decreased in 2012 in Republic of the Congo due to field decline and a well failure at the Azurite field. Natural gas sales volumes in 2012 increased compared to the prior year principally due to more wells producing for a longer period in the Tupper area in Western Canada and higher gas volumes produced in the Eagle Ford Shale.

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

The results of operations for oil and gas producing activities for each of the last three years are shown by major operating areas on pages F-51 and F-52 of this Form 10-K report. Average daily production and sales rates and weighted average sales prices are shown on page 5 of the 2012 Annual Report.

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

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

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

United States crude oil production averaged 26,090 barrels per day in 2012, an annual record for the Company in the U.S., and an increase from 17,148 barrels per day in 2011. The U.S. increase was primarily attributable to an ongoing development drilling program in the Eagle Ford Shale area in South Texas. Heavy oil production in the Western Canada Sedimentary Basin of 7,241 barrels per day in 2012 was about flat with 2011. Crude oil production offshore Canada fell from 9,204 barrels per day in 2011 to 6,986 barrels per day in 2012 essentially due to more downtime for maintenance at the Terra Nova field and well decline at the Hibernia field. Synthetic oil production of 13,830 barrels per day in 2012 slightly exceeded 2011 volumes of 13,498 per day. Crude oil and liquids production in Malaysia averaged 52,663 barrels per day in 2012, up from 48,551 barrels per day in 2011, with the increase mainly due to additional wells brought on production at the Kikeh field. Oil production in Republic of the Congo fell to 2,078 barrels per day in 2012 after averaging 4,989 barrels per day in 2011, with the reduction due to a well that went off production during 2012 and normal decline at other wells in the field. Crude oil production in the U.K. was 3,458 barrels per day in 2012 compared to 2,423 barrels per day in 2011. The U.K. increase in 2012 was primarily at Schiehallion, where better overall performance more than offset lower volumes at Mungo/Monan. Expected sales of all U.K. oil and natural gas operations in early 2013 led the Company to report these U.K. E&P activities as discontinued operations for all periods presented in the consolidated financial statements.

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

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

Natural gas sales volumes in the U.S. were 53.0 MMCF per day in 2012, up from 2011 production of 47.2 MMCF per day as higher production in the Eagle Ford Shale area more than offset declines at fields in the Gulf of Mexico. Natural gas volumes in Western Canada increased from 188.8 MMCF per day in 2011 to 217.0 MMCF per day in 2012 essentially due to higher gas volumes produced at the Tupper area, as more wells were on production at Tupper West during 2012. Natural gas sales volumes offshore Sarawak, Malaysia, averaged 174.3 MMCF per day in 2012 following volumes of 177.0 MMCF per day in 2011. Gas sales at the Kikeh field averaged 42.4 MMCF per day in 2012, up from 40.5 MMCF per day the prior year. Natural gas sales volumes in the U.K. reported as discontinued operations fell from 3.9 MMCF per day in 2011 to 3.4 MMCF per day in 2012 due to well decline at the Mungo/Monan field during the later year.

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

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

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

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

The Company's average realized oil sales price of $94.18 in 2011 for continuing operations was an increase of 41% compared to 2010. The average price of 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 in 2011. Dated Brent prices, for example, rose 40% during 2011. 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; and crude oil in Republic of the Congo sold at $103.02 per barrel in 2011, an increase of 38% from 2010.

The Company's North American natural gas prices retracted in 2012 compared to 2011, while prices in other areas were a bit stronger in 2012. North American natural gas sales prices were hurt by an oversupply of gas caused by both a growing profile of unconventional gas production on the continent and an unusually warm winter season in the primary gas consuming markets in the U.S. during 2012. The Company's average sales prices for natural gas in North America decreased 35% to $2.65 per thousand cubic feet (MCF) in 2012, which was composed of a 34% decline to $2.76 per MCF in the U.S. and a 36% decline to $2.62 per MCF in Canada. Natural gas produced offshore Sarawak sold for 6% more in 2012 than in 2011 and averaged $7.50 per MCF in the later year.

Natural gas sales prices in North America in 2011 did not generally increase in concert with crude oil prices during that year. A growing gas supply from unconventional sources such as shale operations kept gas prices in check during 2011. The Company's average realized North American natural gas sales price was $4.08 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.

Based on 2012 sales volumes and deducting taxes at marginal rates, each $1.00 per barrel and $0.10 per MCF fluctuation in prices would have affected 2012 earnings from exploration and production continuing operations by $26.4 million and $12.2 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.

Production expenses for continuing operations were $1,114.8 million in 2012, $1,010.3 million in 2011 and $852.6 million in 2010. 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.

(Dollars per equivalent barrel)	**2012**	2011	2010
United States	**$19.75**	18.05	12.46
Canada			
Excluding synthetic oil	**9.00**	8.65	8.45
Synthetic oil	**44.27**	47.91	42.61
Malaysia	**12.78**	13.66	9.31
Republic of the Congo	**90.08**	26.04	31.30
Worldwide – excluding synthetic oil	**13.71**	13.16	10.39

Production expense per equivalent barrel in the U.S. increased in 2012 compared to 2011 due to a significantly larger proportion of production in the later year coming from the Eagle Ford Shale in South Texas, where the average per-barrel cost exceeded the U.S. average. In 2013 and beyond, the Company anticipates the per-barrel cost for Eagle Ford Shale production to be below the 2012 U.S. average cost. Cost per barrel for Canada conventional oil and gas operations, excluding synthetic oil, was higher in 2012 than 2011 due to additional maintenance costs in the current year at the Terra Nova field. This Canadian cost increase was tempered by higher natural gas production at the lower than average cost Tupper area. Lower future Tupper area production, attributable to reduced drilling levels caused by depressed sales prices, is expected to lead to increases in per-unit production expense at Tupper as well as for overall conventional Canada production in 2013. The reduction in production costs per barrel for synthetic oil operations in 2012 compared to 2011 was attributable to lower natural gas power costs in the current year. Due to anticipated additional government emission and other environmental requirements in 2013 and beyond, the Company expects synthetic oil production expense to be higher on a per-barrel basis in future years. Production expense in Malaysia declined in 2012 compared to 2011 due to less well maintenance and workover costs at the Kikeh field. Per-barrel production expense in 2012 in Republic of the Congo was significantly higher than 2011 due to lower production levels and unsuccessful workover costs at a well in the Azurite field.

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, with the increase 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. Production expense in Republic of the Congo was lower on a per-unit basis in 2011 compared to 2010 due to a reduction in gross costs incurred at the Azurite field in the later year.

Exploration expenses for continuing operations for each of the last three years are shown in total in the following table, and amounts are reported by major operating area on pages F-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.

(Millions of dollars)	**2012**	2011	2010
Dry holes	**$181.9**	251.0	74.9
Geological and geophysical	**32.2**	79.3	64.4
Other	**37.0**	40.9	28.8
	251.1	371.2	168.1
Undeveloped lease amortization	**129.8**	118.2	108.0
Total exploration expenses	**$380.9**	489.4	276.1

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

Dry hole expense was $176.1 million higher in 2011 than 2010 due to more unsuccessful exploratory drilling results in 2011, with the most significant areas including Brunei, Indonesia, Southern Alberta and Suriname. Lower dry hole costs in 2011 in Malaysia and Republic of the Congo somewhat offset these higher costs. G&G expenses were $14.9 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 2011 included lower seismic spending in Republic of the Congo. Other exploration costs were $12.1 million more in 2011 than 2010 mostly due to higher office costs for exploration activities in Brunei, Indonesia and Kurdistan region of 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 both Eagle Ford Shale leases in South Texas and the Montney area leases in Western Canada.

The Company's E&P operations recorded an impairment charge of $200.0 million in 2012 for oil production operations at the Azurite field, offshore Republic of the Congo, compared to an impairment charge of $368.6 million for Azurite in 2011. The current year charge was required due to the removal of all proved reserves at year-end 2012 following the Company's decision to cease redrilling operations on a well that went off production during the year. The reserves associated with the remaining producing wells were insufficient to allow for booking as proved reserves due to uneconomic results. The 2011 impairment charge to reduce the carrying value of Azurite to fair value was necessitated by a reduction in the field's proved oil reserves at year-end 2011 due to poor performance for certain wells.

Depreciation, depletion and amortization expense for continuing exploration and production operations totaled $1,244.4 million in 2012, $956.0 million in 2011 and $982.6 million in 2010. The $288.4 million increase in 2012 compared to 2011 was primarily caused by higher overall volumes of oil and natural gas sold during the current year. Additionally, the average per-unit depreciation rate increased in 2012, primarily due to a higher mix of production from the Eagle Ford Shale and a higher unit rate at Kikeh due to development drilling activities at the field. The $26.6 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 exploration and production business recorded expenses of $38.4 million in 2012, $33.8 million in 2011 and $28.8 million in 2010 for accretion on discounted abandonment liabilities. Because the liability for future abandonment of wells and other facilities is carried on the balance sheet at a discounted fair value, accretion must be recorded annually so that the liability will be recorded at full value at the projected time of abandonment. The $4.6 million increase in accretion expense in 2012 compared to 2011 was due to additional wells drilled during the later year in Malaysia and higher estimated abandonment costs for wells in the Gulf of Mexico and for synthetic oil operations at Syncrude. The $5.0 million increase in accretion costs in 2011 compared to 2010 was attributable to a higher number of wells drilled in 2011 in the Eagle Ford Shale and Montney areas and higher overall future estimated abandonment cost liabilities for Gulf of Mexico wells and synthetic oil operations at Syncrude.

The effective income tax rate for exploration and production continuing operations was 40.1% in 2012, 52.6% in 2011 and 41.2% in 2010. The overall effective income tax rate was significantly lower in 2012 than 2011 mostly due to tax benefits of $108.3 million recorded in 2012 associated with exploration activities in Republic of the Congo and Suriname. Additionally, 2012 had lower exploration expenses in foreign jurisdictions where no tax benefit is available at the present time due to lack of available revenue needed to realize a current or future benefit. The effective tax rate was significantly higher in 2011 than 2010 due to no tax benefit recorded on the $368.6 million 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 Block P expenses are deductible against taxable income generated in Block K Malaysia. The effective tax rates in all three years exceeded the U.S. statutory tax rate of 35.0% due to higher overall foreign tax rates and exploration and other expenses in areas where current tax benefits cannot be recorded by the Company. Tax jurisdictions with no current tax benefit on expenses primarily include certain non-revenue generating areas in Malaysia as well as 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 Peninsular Malaysia.

At December 31, 2012, 94.6 million barrels of the Company's U.S. proved oil reserves and 130.9 billion cubic feet of U.S. proved natural gas reserves were undeveloped. Approximately 82% 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 134.6 billion cubic feet, with the migration of these reserves, primarily in the Tupper and Tupper West areas, dependent on both development drilling and completion of processing and transportation facilities. In Block K Malaysia, oil reserves of 12.6 million barrels for the Kakap field are undeveloped pending completion of the main facilities and additional development drilling directed by another company. Additionally, the Kikeh field had undeveloped oil reserves of 8.0 million barrels, which are subject to further drilling before being moved to developed. Also in Malaysia, there were 145.9 billion cubic feet of undeveloped natural gas reserves at various fields offshore Sarawak at year-end 2012, which were held under the undeveloped 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 20.6 million and 17.4 million equivalent barrels of oil, respectively, at December 31, 2012. On a worldwide basis, the Company spent approximately $3.30 billion in 2012, $1.88 billion in 2011 and $1.27 billion in 2010 to develop proved reserves.

Refining and Marketing – The Company's refining and marketing (R&M) operations generated earnings from continuing operations of $157.6 million in 2012, $190.3 million in 2011 and $130.6 million in 2010. The R&M earnings reduction of $32.7 million in 2012 compared to 2011 was driven primarily by a weaker U.S. retail marketing sales margin of $0.027 per gallon, and lower earnings and an impairment charge for U.S. ethanol production operations. These unfavorable results in the U.S. were partially offset by improved refining and marketing margins in the U.K. in 2012 compared to the prior year. 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 Company has announced its intention to separate its U.S. downstream business into a separate publicly owned company as well as its intention to divest its U.K. refining and marketing operations. The Meraux, Louisiana and Superior, Wisconsin refineries were sold in 2011 and have been reported as discontinued operations for all periods presented.

The Company's United States R&M operations generated earnings from continuing operations of $105.4 million in 2012, down from $223.6 million in 2011 and $165.3 million in 2010. U.S. R&M operations include retail and wholesale fuel marketing operations, along with two ethanol production facilities. U.S. R&M profits decreased $118.2 million in 2012 compared to 2011. Margins for retail fuel marketing operations declined from $0.156 per gallon in 2011 to $0.129 per gallon in 2012. The margin decline in the current year was primarily attributable to generally rising wholesale gasoline prices which were not fully recovered from customers at the pump. Fuel volumes sold by the retail marketing business in 2012 on a per store basis were lower than the prior year by 0.3%. Also, the U.S. retail business was adversely affected in 2012 by higher allocated administrative expense. The U.S. retail operating results benefited from stronger profits on merchandise sales in 2012 as margins as a percent of sales improved by 5% in the current year. U.S. ethanol production operations experienced significantly weaker margins in 2012 compared to 2011. Based on these squeezed margins and an expectation of weak results in future periods, the Company recorded an after-tax impairment charge of $39.6 million in 2012 to write down the carrying value of its Hereford, Texas ethanol production facility.

The $58.3 million increase in U.S. income from continuing operations 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 2010. 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 later year.

United States refined product sales volumes (including discontinued operations) averaged 337,900 barrels per day in 2012, compared to 420,737 barrels per day in 2011 and 450,100 barrels per day in 2010. The decreases in 2012 and 2011 versus each prior year were primarily due to the sale of the two U.S. refineries near the end of September 2011. Sales volume in 2011 included nine months of finished products made prior to the sale of the refineries near the end of September 2011. A full year of ethanol production in 2012 from the Hereford facility, which commenced operation in early 2011, partially offset the reduced sales volume due to the sale of the refineries in 2011. The retail marketing business added 37 stations in 2012, 29 stations in 2011 and 51 stations in 2010. The U.S. retail marketing network included 1,165 stations at year-end 2012. As previously announced, the Company entered into an agreement with Wal-Mart Stores near year-end 2012 that will allow the Company to obtain sites to build additional fueling stations at more than 200 Walmart supercenter stores. These store additions are expected to be phased in over approximately the next three years.

United Kingdom R&M operations generated a profit of $52.2 million in 2012 compared to losses of $33.3 million in 2011 and $34.7 million in 2010. Results in 2012 were $85.5 million better than 2011 for U.K. R&M operations primarily due to much stronger margins at the Milford Haven, Wales, refinery in the latest year. During the two-year period of 2011 and 2010, U.K. refining margins were hurt by weak demand, leading to an oversupply of motor fuel products in the U.K. and Western Europe. Additionally, in 2012 the U.K. marketing operations generated stronger margins on sale of fuel products compared to 2011. In 2011, operating results for U.K. R&M operations improved by $1.4 million compared to 2010, primarily caused by slightly better refining margins and higher throughput volumes in 2011 due to a two-month plant wide turnaround at the Milford Haven refinery in 2010.

Unit margins in the United Kingdom averaged $1.94 per barrel in 2012, $(0.67) per barrel in 2011 and $(1.47) per barrel in 2010. Overall refined product sales volumes in the U.K. averaged 137,049 barrels per day in 2012, up 1% compared to 2011. Sales volumes of refined products in the U.K. increased 57% in 2011 compared to 2010 and averaged 135,697 barrels per day. The significant volume increase in 2011 was essentially due to downtime for a 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 $98.5 million in 2012, $75.0 million in 2011 and $157.9 million in 2010.

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

The net cost of corporate activities in 2011 was $82.9 million lower than in 2010, primarily due to more favorable effects of foreign currency exchange. The effect of foreign currency 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 2010. The corporate area also benefited in 2011 from higher interest income of $3.2 million compared to 2010, principally due to interest received in 2011 on a U.S. Federal royalty refund. 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 2011, 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 employee compensation and professional services.

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 has accounted for the Superior, Wisconsin and Meraux, Louisiana refineries and associated marketing assets as discontinued operations in all periods presented.

The Company also entered into contracts in late 2012 to sell its U.K. oil and gas operations. The sales are expected to be completed in the first quarter of 2013. The results of the U.K. oil and gas operations for all periods have been presented as discontinued operations in the Consolidated Statements of Income. The assets and liabilities related to these operations to be sold have been reported as held for sale in the December 31, 2012 Consolidated Balance Sheet.

Income from discontinued operations totaled $6.8 million in 2012, $143.2 million in 2011 and $49.0 million in 2010. Income from discontinued operations in 2012 included profitable results of U.K. oil and gas operations, which were partially offset by net costs for tax adjustments and other matters related to U.S. refineries sold in 2011. The primary reason for the $136.4 million decline in 2012 income from discontinued operations compared to the prior year was a sizable operating profit of $113.1 million in the first nine months of 2011 for the two U.S. refineries sold. Results in 2011 also included an after-tax gain on disposal of the refineries of $18.7 million. In July 2012, the United Kingdom enacted tax changes that limited tax relief on oil and gas decommissioning costs to 50%, a reduction from the 62% tax relief previously allowed for these costs. This tax rate change led to a net reduction of income from discontinued operations of $5.5 million in 2012. The prior year results included a larger unfavorable effect from tax rate changes in the U.K., which is further described in the following paragraph.

Income from discontinued operations was $143.2 million in 2011. This 2011 income included U.S. refinery operating profits of $113.1 million, an after-tax gain on sale of the two U.S. refineries of $18.7 million, and operating profits of $11.5 million from U.K. oil and gas operations. U.S. refinery 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. The after-tax gain from disposal of the two refineries included a gain on sale of the Superior refinery and associated inventories of $77.6 million and a loss on sale of the Meraux refinery and associated inventories of $58.9 million. The net gain on disposal was based on the selling prices of the refineries, plus the sales of all associated inventories. These inventories were sold at fair value, which was significantly above the last-in, first-out carrying value of these assets. In 2011, the U.K. government enacted a 12% supplemental tax on oil and gas company profits in that country. This tax increase reduced income from discontinued operations in 2011 by $14.5 million, primarily to increase the recorded balance for deferred income taxes that will be paid in future years at the new higher rate. The rate change increased the effective tax rate to 62% in the U.K.

Capital Expenditures

As shown in the selected financial data on page 26 of this Form 10-K report, capital expenditures from continuing operations, including exploration expenditures, were $4.33 billion in 2012, compared to $2.88 billion in 2011 and $2.32 billion in 2010. These amounts excluded capital expenditures of $57.2 million in 2012, $68.3 million in 2011 and $128.8 million in 2010 related to discontinued operations, which were associated with two U.S. petroleum refineries sold during 2011 and U.K. oil and gas assets expected to be sold in early 2013. Capital expenditures included $251.1 million, $371.2 million and $168.1 million, respectively, in 2012, 2011 and 2010 for exploration costs that were expensed.

Capital expenditures for exploration and production continuing operations totaled $4.19 billion in 2012, $2.75 billion in 2011 and $2.02 billion in 2010, representing 97%, 96% and 87%, respectively, of the Company's total capital expenditures from continuing operations for these years. E&P capital expenditures in 2012 included $132.5 million for acquisition of undeveloped leases, which primarily included leases acquired in the Gulf of Mexico, the Eagle Ford Shale area of South Texas and in Northwest Alberta, Canada, $450.6 million for exploration activities, $3.29 billion for development projects and $311.5 million for acquisition of proved properties in Canada and the Gulf of Mexico. Exploration activities primarily included exploratory drilling in the

United States, Southern Alberta in Canada, Block H in Malaysia, Republic of the Congo, the Kurdistan region of Iraq and Brunei. Other primary exploration activities were associated with geophysical data acquisitions in the U.S. and various foreign countries. Development expenditures included $1.11 billion in the Eagle Ford Shale; $157.3 million at the Tupper and Tupper West areas; $200.1 million for deepwater fields in the Gulf of Mexico; $627.8 million for Kikeh; $558.6 million for oil and natural gas development activities in SK Blocks 309/311; $107.0 million and $83.9 million for the Kakap and Siakap developments, respectively, in Block K, Malaysia; $125.1 million for Syncrude; $222.4 million for Western Canada heavy oil projects; and $73.1 million for the Terra Nova and Hibernia oil fields, offshore Newfoundland.

Capital expenditures in 2011 from E&P continuing operations included $279.3 million for undeveloped lease acquisitions, $23.5 million associated with a contract revision at the Azurite field, $559.7 million of exploration activities and $1.89 billion for development programs. Lease acquisitions were primarily associated with activities in the Eagle Ford Shale area of South Texas and exploration concessions in the Kurdistan region of Iraq. Exploration costs principally related to exploratory drilling at resource plays in North America, including the Eagle Ford Shale in South Texas and new areas in Southern Alberta, plus wildcat drilling activities in Brunei, Indonesia and Suriname. Development projects in 2011 primarily included spend of $572.2 million at the Tupper 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. 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 $133.7 million in 2012, $122.3 million in 2011 and $290.1 million in 2010. These amounts represented 3%, 4% and 13% of capital expenditures of the Company in 2012, 2011 and 2010, respectively. Total refining and marketing capital expenditures above excluded $48.1 million and $117.3 million in 2011 and 2010, respectively, for U.S. refineries sold in 2011, which are classified as discontinued operations. Marketing expenditures amounted to $110.7 million in 2012, $84.9 million in 2011 and $185.4 million in 2010. Marketing capital spending in all three years was principally related to new station construction in the U.S. market. The Company added 37 stations within its U.S. retail gasoline network in 2012, after adding 29 in 2011 and 51 in 2010. Refining capital spend within continuing operations totaled $14.5 million in 2012, $14.7 million in 2011 and $59.8 million in 2010. These expenditures related to the Milford Haven, Wales refinery, and in 2012 and 2011 principally included minor capital improvements, while the majority of 2010 spend related to costs to complete expansion of the crude oil throughput capacity at Milford Haven to 135,000 barrels per day. Refining capital spending for discontinued operations during 2011 and 2010 primarily included costs at Meraux to reduce benzene production and construct a new laboratory, and at Superior to meet compliance with ultra-low sulfur diesel and Mobile Source Air Toxic requirements. Capital expenditures related to ethanol operations in the U.S. totaled $8.5 million in 2012, $22.7 million in 2011 and $44.9 million in 2010. 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.

Cash Flows

Operating activities – Cash provided by operating activities was $3.06 billion in 2012, $2.15 billion in 2011 and $3.13 billion in 2010. Cash flows associated with formerly owned U.S. refineries and the held for sale U.K. oil and gas production business have been classified as discontinued operations in the Company's consolidated financial statements. Cash provided by operating activities included cash from these discontinued operations of $61.1 million in 2012, $185.5 million in 2011 and $159.5 million in 2010. Cash provided by continuing operations in 2012 was $1.04 billion more than 2011 primarily due to a lower use of cash to build working capital other than cash, higher income from continuing operations in the current year, and higher non-cash expenses for depreciation and deferred taxes in 2012. Cash provided by continuing operations in 2011 was

$1.01 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 in 2011 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 flow from continuing operations in 2010 included cash receipts of $286.4 million related to recovery of U.S. Federal royalties and associated interest income. The 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 $40.4 million in 2012, $21.5 million in 2011 and $36.5 million in 2010. Operating cash flows were reduced by payments of income taxes of $567.0 million in 2012, $938.9 million in 2011 and $585.8 million in 2010. The total reductions of operating cash flows for interest paid during the three years ended December 31, 2012, 2011 and 2010 were $48.7 million, $53.3 million and $53.9 million, respectively.

Investing activities – Cash proceeds from property sales classified as continuing operations were $0.6 million in 2012, $27.8 million in 2011 and $2.2 million in 2010. 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. Other investing activities for discontinued operations included cash payments for capital expenditures of $58.2 million in 2012, $68.4 million in 2011 and $127.9 million in 2010. Additionally, the two U.S. refineries which were sold used cash of $1.5 million in 2011 and $37.5 million in 2010 for maintenance turnarounds. Property additions and dry hole costs for continuing operations used cash of $3.67 billion in 2012, $2.60 billion in 2011 and $2.19 billion in 2010. 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 $1.62 billion, $1.69 billion and $2.39 billion was spent in 2012, 2011 and 2010, 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 $2.04 billion in 2012, $1.77 billion in 2011 and $2.55 billion in 2010. Cash of $12.8 million in 2012, $5.4 million in 2011 and $61.4 million in 2010 was used for turnarounds at the Milford Haven refinery, at Syncrude and at U.S. ethanol plants. The high spend in 2010 was attributable to a plant-wide turnaround at Milford Haven.

Financing activities – During 2012, the Company sold $2.0 billion of long-term notes. The proceeds of these notes were primarily used to repay $350.0 million of notes that matured in 2012, to repay other debt, to fund a special dividend totaling $486.1 million, to fund $250.0 million of an announced stock buyback program of up to $1.0 billion, and to fund a portion of the Company's development capital expenditures. Through December 31, 2012, the Company had paid $250.0 million to acquire 3.87 million of its Common shares under an accelerated stock repurchase program (ASR) with a major financial institution. Additional shares may be delivered to the Company upon completion of the ASR in 2013. During 2011 and 2010, the Company used available cash flow to repay $340.0 million and $414.0 million, respectively, of debt. The debt reduction in 2011 was accomplished with proceeds from sale of the two U.S. refineries. The 2010 debt reduction included a full repayment of the nonrecourse loan used to partially finance the acquisition of the Hankinson, North Dakota ethanol plant. Cash proceeds from stock option exercises and employee stock purchase plans, including income tax benefits on stock options, amounted to $15.0 million in 2012, $20.4 million in 2011 and $54.7 million in 2010. In 2012, the Company paid $7.0 million of fees associated with sales of the $2.0 billion of long-term notes. In 2011, the Company used cash of $7.9 million for fees and other expenses associated with renewing its primary $1.5 billion committed credit facility that expires in June 2016. In 2012, 2011 and 2010, cash of $3.3 million, $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 $714.4 million in 2012, $212.8 million in 2011 and $201.4 million in 2010. The Company increased its normal dividend rate by 14% in 2012 as the annualized dividend was raised from $1.10 per share to $1.25 per share effective in the third quarter 2012. The Company had previously raised its annualized dividend rate from $1.00 per share to $1.10 per share beginning in the third quarter of 2010. Additionally, in December 2012, the Company paid a special dividend of $2.50 per share.

Financial Condition

Year-end working capital (total current assets less total current liabilities) amounted to $699.5 million in 2012 and $622.7 million in 2011. 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 $571.2 million below fair value at December 31, 2012. Cash and cash equivalents at the end of 2012 totaled $947.3 million compared to $513.9 million at year-end 2011. In addition, the Company had short-term investments in Canadian government treasury securities of $115.6 million at year-end 2012. These short-term investments could quickly be converted to cash if a need for funds in Canada arose.

Long-term debt increased by $1,995.6 million in 2012. A portion of the increase in long-term debt in 2012 was associated with issuance of $500.0 million of long-term notes in May 2012. The proceeds from these notes were used to repay $350.0 million of notes that matured in May 2012 and which were classified as a current liability at December 31, 2011. In late 2012, the Company sold $1.5 billion of long-term notes in the market. Part of the proceeds of these notes were used to pay a $2.50 per share special dividend that totaled $486.1 million and to fund a $250.0 million stock buyback through an accelerated stock repurchase plan with a major financial institution. The remainder of the note proceeds were used to repay debt that was then outstanding under the Company's committed credit facility and to fund capital expenditures. At December 31, 2012, long-term debt was 20.1% of total capital employed. During 2011, long-term debt decreased by $689.8 million 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 due in 2012 to a current liability. Stockholders' equity was $8.94 billion at the end of 2012 compared to $8.78 billion at the end of 2011 and $8.20 billion at the end of 2010. 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 2012 balance sheet compared to 2011 included a $416.5 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 $115.6 million at year-end 2012 and $532.1 million at year-end 2011. These short-term investments were reduced in late 2012, with the proceeds partially used to fund a purchase of Seal heavy oil field properties in Western Canada. The remainder of the investment proceeds was used to fund other capital investments in Canada and for an intercompany loan to the U.K. business which was repaid in early 2013. These slightly longer-term Canadian investments were purchased in each year because of a tight supply of shorter-term securities available for purchase in Canada. A $299.2 million increase in accounts receivable in 2012 was primarily caused by higher sales prices for crude oil and finished products, and higher natural gas sales volumes sold on credit terms by the Company. Inventory values were $85.7 million more at year-end 2012 than in 2011 mostly due to larger levels of crude oil held in storage within U.K. downstream operations, plus more drilling equipment inventory held within the E&P business in the later year. Prepaid expenses increased $242.4 million in 2012 primarily due to prepaid income taxes in the U.S. and Canada, plus higher levels of prepaid insurance costs at year-end 2012. Short-term deferred income tax assets were $1.6 million higher at year-end 2012 compared to 2011. Current assets held for sale of $15.1 million at December 31, 2012 primarily represent accounts receivable and crude oil and other inventory costs associated with U.K. oil and gas producing assets to be sold in early 2013. Net property, plant and equipment increased by $2.54 billion in 2012 as the level of property additions during the year exceeded the amounts of depreciation, amortization and impairment expenses recorded during the year. Goodwill increased $1.2 million in 2012 due to a stronger Canadian dollar exchange rate versus the U.S. dollar. Deferred charges and other assets decreased $22.3 million due to amortization of deferred turnaround costs associated with the Milford Haven refinery and transfer to Property, Plant and Equipment of long-lead equipment that was placed in service. These were somewhat offset by higher deferred financing costs associated with sale of $2.0 billion of notes during 2012. Assets held for sale-noncurrent of $208.2 million at year-end 2012 represents primarily property and equipment associated with U.K. oil and gas producing assets to be sold in early 2013. Current maturities of long-term debt at year-end 2012 was $350.0 million lower than at the prior year-end due to repayment of $350.0 million of notes payable that matured during 2012 and replacement of these notes with $500.0 million of 10-year notes that mature in 2022 and which have been classified as long-term debt at December 31, 2012. Accounts payable increased by $862.3 million at year-end 2012 compared to 2011 primarily due to higher capital and operating expenses owed to vendors in the U.S., Malaysia and Republic of the Congo at year-end 2012, partially offset by lower amounts owed for purchased crude oil feedstocks at the Milford Haven refinery in 2012. Income taxes payable was $18.1 million higher at year-end 2012 than at the end of 2011, primarily due to higher levels of taxes owed in 2012 for Malaysian operations. Other taxes payable at year-end 2012 was $3.4 million higher than in 2011 mostly due to higher excise taxes owed by U.S. downstream operations, partially offset by lower withholding taxes owed by Canadian operations. Other accrued liabilities increased by $22.9 million at year-end 2012 mostly due to higher amounts owed for compensation, retirement and asset dismantlement and reclamation costs. The current portion of deferred income tax liabilities decreased $20.0 million in 2012 due to lower short-term temporary differences for tax deductions in Canada in the current year. Liabilities associated with assets held for sale-current of $47.5 million at December 31, 2012 primarily represent U.K. oil and gas operations payables to vendors and tax authorities. Noncurrent deferred income tax liabilities were $314.2 million higher at year-end 2012 mostly due to accelerated tax depreciation associated with the Company's 2012 capital expenditures, primarily in the U.S., Canada and Malaysia. The liability associated with future asset retirement obligations increased by $108.7 million at year-end 2012 mostly due to higher estimated future costs to abandon oil and gas properties in the U.S., Canada and Malaysia. Deferred credits and other liabilities were $76.9 million more in 2012 compared to 2011 primarily due to higher noncurrent retirement plan liabilities and other long-term obligations at year-end 2012. Liabilities associated with assets held for sale-noncurrent of $141.2 million primarily represents abandonment and deferred tax obligations associated with U.K. oil and gas assets to be sold in early 2013. Total stockholders' equity of the Company increased by $163.6 million in 2012. The components of this increase in stockholders' equity are reflected in the Consolidated Statement of Stockholders' Equity on page F-8 of the consolidated financial statements.

Murphy had commitments for future capital projects of approximately $2.42 billion at December 31, 2012, including $977.8 million for field development and future work commitments in Malaysia, $242.0 million for costs to develop deepwater Gulf of Mexico fields, $474.1 million for work in the Eagle Ford Shale, and $146.8 million and $124.1 million for future work commitments offshore Brunei and Cameroon, respectively.

The primary sources of the Company's liquidity are internally generated funds, access to outside financing and working capital. The Company uses its internally generated funds to finance the major portion of its capital and other expenditures, but it also maintains lines of credit with banks and borrows as necessary to meet spending requirements. At December 31, 2012, 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 2012. The most restrictive covenants under this committed credit facility limit the Company's long-term debt to capital ratio (as defined in the agreements) to 60%. The committed credit facility expires in June 2016. At December 31, 2012, the Company had uncommitted bank credit lines of approximately $320.0 million, but no borrowings were outstanding under these lines. The Company's ratio of long-term debt to total capital was 20.1% at year-end 2012. In October 2012, the Company filed a Form S-3 registration statement with the U.S. Securities and Exchange Commission which permits the offer and sale of debt and/or equity securities. The Company used this shelf registration and a former one in 2012 to sell long-term notes totaling $2.0 billion. The current shelf registration will expire in October 2015. Current financing arrangements are set forth more fully in Note E to the consolidated financial statements. Based on the anticipated level of capital expenditures the Company has budgeted during 2013, the Company anticipates that it will need to borrow under its long-term credit facility during 2013. The Company's ratio of earnings to fixed charges was 16.6 to 1 in 2012, 15.1 to 1 in 2011 and 14.0 to 1 in 2010.

Cash and invested cash are maintained in several operating locations outside the United States. At December 31, 2012, cash, cash equivalents and cash temporarily invested in Canadian government securities held outside the U.S. included $184.2 million in Canada, $580.2 million in Malaysia and $78.0 million in the U.K. In certain cases, the Company could incur taxes or other costs should these cash balances be repatriated to the U.S. in future periods. This could occur due to withholding taxes and/or potential additional U.S. tax burden when less than the U.S. tax rate of 35% has been paid for cash taxes in foreign locations. A lower cash tax rate is often paid in the U.S. and foreign countries in the early years of operations when accelerated tax deductions exist to incent oil and gas investments; cash tax rates are generally higher in later years after accelerated tax deductions in early years are exhausted. Canada collects a 5% withholding tax on any cash repatriated to the U.S. See Note H of the consolidated financial statements for further information regarding potential tax expense that could be incurred upon distribution of foreign earnings back to the United States.

Environmental Matters

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

Murphy allocates a portion of its capital expenditure program to comply with environmental laws and regulations, and such capital expenditures were $81.8 million in 2012 and are projected to be $86.9 million in 2013.

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

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

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

Murphy's 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. The Board has 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 two Superfund sites. At one site, the Company has thus far been unable to ascertain any association with the superfund site; Murphy intends to request further information as to the Company's connection to the site. The potential total cost to all parties to perform necessary remedial work at these sites 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 sites 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 these sites or other Superfund sites. The Company believes that its share of the ultimate costs to remediate these Superfund sites 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, 2012.

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

Water

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

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

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

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

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.

The European Union has adopted an Emissions Trading Scheme in response to the Kyoto Protocol in order to achieve reductions in greenhouse gas emissions. Murphy's refinery at Milford Haven, Wales, currently has the most exposure to these requirements and may require purchase of emission allowances to maintain compliance with environmental permit requirements. These environmental expenditures are expensed as incurred. In 2011, Murphy was notified by the Environment Agency (EA) that it failed to surrender proper emission allowances, which Murphy self-reported to the EA in 2010. The EA has recommended a civil penalty of $1.7 million for this matter. The Company has not yet paid the proposed civil penalty and is pursuing legal means 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.

Environmental Stewardship

The Company recognizes the importance of environmental stewardship as a core component of its mission as a responsible international energy company and has implemented sufficient disclosure controls and procedures to capture and process environmental, safety and climate-change related information. As a companion to Murphy's worldwide EHS Policy, the Company's Web site also contains a statement on climate change. Not only does this statement on climate change include Murphy's goal of reducing greenhouse gas emissions on an absolute basis while growing its upstream 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 in a strong oil price environment. As noted elsewhere, oil and natural gas prices have been extremely volatile over the last several years. Oil prices have been strong in the last few years, while North American natural gas prices have been generally weakening due to oversupply of natural gas in this market. Oil prices in the current range of $90 per barrel and above generally lead to strong demand for oil field services. The prices for oil field goods and services generally rise in periods of higher oil prices and do not usually decline as significantly when oil and gas prices retreat. Should oil prices rise further in future periods, the Company anticipates that prices for certain oil field equipment and services could rise sharply. Due to the volatility of oil and natural gas prices, it is not possible to determine what effect these prices will have on the future cost of oil field goods and services.

Accounting changes and recent accounting pronouncements – In September 2011, the Financial Accounting Standards Board (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 was effective for goodwill impairment tests beginning in 2012. The adoption of this standard in 2012 did not have a significant effect on Murphy's 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 was effective for the Company beginning in the first quarter of 2012. The adoption of this guidance in 2012 did not have a significant effect on the Company's consolidated financial statements.

In February 2013, FASB issued a new rule that requires additional disclosures for reclassification adjustments from Accumulated other comprehensive income (AOCI). These additional disclosures include changes in AOCI balances by component and significant items reclassified out of AOCI. These disclosures must be presented either on the face of the affected financial statement or in the notes to the financial statements. The disclosures are effective for Murphy beginning in the first quarter of 2013 and are to be provided on a prospective basis.

The United States Congress passed the Dodd-Frank Act (the Act) in 2010. As mandated by the Act, the U.S. Securities and Exchange Commission (SEC) has recently issued rules regarding annual disclosures for purchases of "conflict minerals" and payments made to the U.S. Federal and all foreign governments by extractive industries, including oil and gas companies. These two rules are described below.

- "Conflict minerals" are defined as tin, tantalum, tungsten and gold which originate from the Democratic Republic of Congo or an adjoining country. The Company is currently investigating whether its activities will require an annual "conflict minerals" filing. If applicable, the first annual report for conflict minerals must be filed by May 31, 2014 for the calendar year of 2013.
- Due to its activities as a worldwide exploration company and a producer of oil and natural gas in several countries, the Company will be required to report annual payments made to the U.S. Federal and all foreign governments. The recent SEC rules require disclosures of (a) the type and total amount of payments made for each project associated with extraction activities, and (b) the type and total amount of payments made to each government. The types of payments covered by the rules include taxes, royalties, fees, production entitlements, bonuses and other material benefits that are part of the commonly recognized revenue stream

for oil and gas companies. The annual disclosure filing must be made within 150 days of the fiscal year-end (May 30, 2014 for the 2013 filing) and will first be required for fiscal years ending after September 30, 2013. The transition rules for 2013 allow Murphy's first filing to disclose payments for the period from October 1 to December 31, 2013. The oil and gas industry has challenged in U.S. Federal court the rules set forth by the SEC. The Company cannot predict the outcome of this court challenge.

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

- *Proved oil and gas reserves* – Proved oil and gas reserves are defined by the SEC as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether a deterministic method or probabilistic method is used for the estimation. Proved developed oil and gas reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well, or through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Although the Company's engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. SEC rules require the Company to use an unweighted average of the oil and gas prices in effect at the beginning of each month of the year for determining quantities of proved reserves. These historical prices often do not approximate the average price that the Company expects to receive for its oil and natural gas production in the future. The Company often uses significantly different oil and natural gas price and reserve assumptions when making its own internal economic property evaluations. Estimated reserves are subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserves quantities. Reserves revisions inherently lead to adjustments of the Company's depreciation rates and the timing of settlement of asset retirement obligations. Downward reserves revisions can also lead to significant impairment expense. The Company cannot predict the type of oil and natural gas reserves revisions that will be required in future periods. The Company's proved reserves of oil and natural gas are presented on pages F-48 and F-49 of this Form 10-K.

  Murphy has utilized reliable geologic and engineering technology in 2011 and 2012 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 reserves 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 reasonably certain results.

  Oil proved reserves revisions

  Proved oil reserves in the U.S. had positive revisions in 2012 which arose from improved performance in the Eagle Ford Shale area and at the Medusa field in the Gulf of Mexico. Negative conventional proved oil reserves revisions in Canada in 2012 occurred due to a lower recovery assessment for certain wells drilled in the Seal heavy oil area in Western Canada. Negative synthetic oil reserves revisions in 2012 at Syncrude were related to a change in entitlement that increased government royalties based on a recent projection for future operating and capital spending. The negative proved oil reserves revision in Republic of the Congo was associated with poor well performance, a well that prematurely went off production, and generally uneconomic remaining future production levels. In 2011, positive proved oil reserves revisions in the U.S. were primarily associated with better production at the Medusa field in the Gulf of Mexico. Positive 2011 revisions for oil reserves of conventional operations in Canada were mostly attributable to better well performance at the Hibernia field, offshore Eastern Canada. Synthetic oil operations had positive reserves revisions in 2011 due to a change in royalty rate. Positive oil reserves revisions in 2011 in Malaysia were primarily attributable to better production performance at the Kikeh field. Positive oil reserves revisions in the U.K. in 2011 were associated with the Schiehallion field which is being redeveloped by its owners. The negative revision in oil reserves in Republic of the Congo in 2011 was attributable to poor production results for wells in the field. In 2010, a positive revision in U.S. proved oil reserves 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 reserves 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 reserves revision in Malaysia in 2010 primarily related to better well performance at the Kikeh field. A positive proved oil reserves 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.

Natural gas proved reserves revisions

Proved natural gas reserves in the U.S. had positive revisions during 2012 due to improved well performance at several fields in the Gulf of Mexico, plus better well performance in the Eagle Ford Shale area. Proved natural gas reserves in Canada were revised downward in 2012 due to weaker average monthly natural gas prices in the current year that adversely affected certain areas in the Montney formation of Western Canada. Proved natural gas reserves in Malaysia in 2012 had positive revisions due to better well performance and favorable entitlement effects for gas operations offshore Sarawak. In 2011, proved natural gas reserves in the U.S. had negative revisions due to well performance being less than expected in early wells drilled in the gas-prone regions of the Eagle Ford Shale in South Texas. Positive gas reserves revisions in Canada in 2011 were primarily at the Tupper and Tupper West areas based on better than anticipated well performance. Negative gas reserves revisions in Malaysia in 2011 were primarily due to higher sales prices which effectively reduced the entitlement percentage for future production at the Sarawak gas fields. Negative gas reserves revisions in the U.K. in 2011 were essentially caused by revised estimate of gas-cap volumes at the Mungo/Monan field. In 2010, proved natural gas reserves in the U.S. had positive revisions due to better well performance at the Thunder Hawk and Mondo fields in the Gulf of Mexico. The positive gas reserves 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 reserves revisions in the U.K. in 2010 were attributable to better well performance at all gas producing fields.

- *Successful efforts accounting* – The Company utilizes the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration wells are expensed and can have a significant effect on net income. Successful exploration drilling costs and all development capital expenditures are capitalized and systematically charged to expense using the units of production method based on proved developed oil and natural gas reserves as estimated by the Company's engineers.

  In some cases, a determination of whether a drilled well has found proved reserves cannot be made immediately. This is generally due to the need for a major capital expenditure to produce and/or evacuate the hydrocarbon(s) found. The determination of whether to make such a capital expenditure is, in turn, usually dependent on whether additional exploratory wells find a sufficient quantity of additional reserves. Under current accounting rules, the Company holds well costs in Property, Plant and Equipment in the

Consolidated Balance Sheet when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

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

- *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 or ethanol products produced and sold, and future inflation levels. The need to test a long-lived asset for impairment can be based on several factors, including but not limited to a significant reduction in sales prices for oil and/or natural gas, unfavorable revisions of oil or natural gas reserves, expected deterioration of future margins for refining, marketing or ethanol production operations, or other changes to contracts, environmental regulations or tax laws. All of these same factors must be considered when evaluating a property's carrying value for possible impairment. In making its impairment assessments involving exploration and production property and equipment, the Company must make a number of projections involving future oil and natural gas sales prices, future production volumes, and future capital and operating costs. Due to the volatility of world oil and gas markets, the actual sales prices for oil and natural gas have often been quite different from the Company's projections. Estimates of future oil and gas production and sales volumes are based on a combination of proved and risked probable and possible reserves. Although the estimation of reserves and future production is uncertain, the Company believes that its estimates are reasonable; however, there have been cases where actual production volumes were higher or lower than projected and the timing was different than the original projection. The Company adjusts reserves and production estimates as new information becomes available. The Company generally projects future costs by using historical costs adjusted for both assumed long-term inflation rates and known or expected changes in future operations. Although the projected future costs are considered to be reasonable, at times, costs have been higher or lower than originally estimated. In assessing potential impairment involving refining, marketing and ethanol production assets, the Company evaluates its properties when circumstances indicate that the carrying value of an asset may not be recoverable from future cash flows. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events, which include projections of future margins, future capital expenditures and future operating expenses. Future marketing or operating decisions, such as closing or selling certain assets, and future regulatory or tax changes could also impact the Company's conclusion about potential asset impairment. The Company recorded impairment expense in 2012 of $200.0 million for the Azurite field, offshore Republic of the Congo, and $61.0 million for the Hereford, Texas ethanol production facility. The Congo impairment was necessitated by removal of all proved oil reserves at Azurite following an unsuccessful redrill of a well; this result led to uneconomic future oil production operations for the field. The Hereford impairment was based on an expectation of continued weak future ethanol margins at the production facility. The Hereford impairment was determined using available years of futures prices for corn and ethanol, plus a terminal value based on a reasonable multiple of the final year's cash flow. Impairment expense of $368.6 million was recognized in 2011 to reduce the carrying value of the Azurite oil field, offshore Republic of the Congo, to fair value. The expense was necessitated by a significant year-end 2011 reduction of proved oil reserves at this field which was caused by poor well performance. Based on an evaluation of expected future cash flows from properties at year-end 2012, 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 2012. 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 and ethanol 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, 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. During 2012, the Company recognized U.S. tax benefits related to exploration activities in Republic of the Congo and Suriname that totaled $108.3 million. These U.S. benefits arose due to tax deductions for worthless stock investments in these countries. The Company occasionally is challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in its various income tax returns. Although the Company believes that it has adequate accruals for matters not resolved with various taxing authorities, gains or losses could occur in future years from changes in estimates or resolution of outstanding matters.
- *Accounting for retirement and postretirement benefit plans* – Murphy Oil and certain of its subsidiaries maintain defined benefit retirement plans covering most of its full-time employees. The Company also sponsors health care and life insurance benefit plans covering most retired U.S. employees. The expense associated with these plans is determined by management based on a number of assumptions and with consultation assistance from qualified third-party actuaries. The most important of these assumptions for the retirement plans involve the discount rate used to measure future plan obligations and the expected long-term rate of return on plan assets. For the retiree medical and insurance plans, the most important assumptions are the discount rate for future plan obligations and the health care cost trend rate. Discount rates are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate which is the basis for selecting the discount rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Anticipated health care cost trend rates are determined based on prior experience of the Company and an assessment of near-term and long-term trends for medical and drug costs.

Based on bond yields at December 31, 2012, the Company has used a discount rate of 4.18% at year-end 2012 and beyond for the primary U.S. plans. The year-end 2012 discount rate is 0.69% lower than a year earlier; this reduced rate led to an increase in the Company's recorded liabilities for retirement plans compared to a year ago. Although the Company presently assumes a return on plan assets of 6.50% for the primary U.S. plan, it periodically reconsiders the appropriateness of this and other key assumptions. The smoothing effect of current accounting regulations tends to buffer the current year's retirement plan expenses from wide swings in liabilities and asset valuations. The Company's normal annual retirement and postretirement plan expenses, excluding special termination benefits, are expected to increase slightly in 2013 compared to 2012 based on the effects of a growing employee base. In 2012, the Company paid $42.2 million into various retirement plans and $4.7 million into postretirement plans. In 2013, the Company is expecting to fund payments of approximately $42.9 million into various retirement plans and $5.6 million for postretirement plans. The Company could be required to make additional and more significant funding payments to retirement plans in future years. Future required payments and the amount of liabilities recorded on the balance sheet associated with the plans could be unfavorably affected if the discount rate declines, the actual return on plan assets falls below the assumed return, or the health care cost trend rate increase is higher than expected. Although Congress recently passed the Moving Ahead for Progress in the 21st Century Act that permits certain companies to reduce retirement plan contributions in the near term, this Act does not reduce the Company's overall funding requirements in the long-term. As described above, the Company's retirement and postretirement expenses are sensitive to certain assumptions, primarily related to discount rates and assumed return on plan assets. A 0.5% decline in the discount rate would increase 2013 annual retirement and postretirement expenses by $8.1 million and $1.0 million, respectively, and a 0.5% decline in the assumed rate of return on plan assets would increase 2013 retirement expense by $2.3 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.

	Amount of Obligations				
(Millions of dollars)	Total	2013	2014-2015	2016-2017	After 2017
Total debt including current maturities	$ 2,245.2	0.1	0.1	550.0	1,695.0
Operating and other lease obligations	1,764.1	225.8	425.1	264.1	849.1
Purchase obligations	3,826.1	2,489.6	1,153.9	162.6	20.0
Other long-term liabilities, including debt interest	2,311.7	143.8	308.3	285.1	1,574.5
Total	$10,147.1	2,859.3	1,887.4	1,261.8	4,138.6

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, 2012 that expire in future periods are shown below.

	Amount of Commitments				
(Millions of dollars)	Total	2013	2014-2015	2016-2017	After 2017
Financial guarantees	$ 7.8	–	3.2	1.2	3.4
Letters of credit	299.0	296.0	3.0	–	–
Total	$306.8	296.0	6.2	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 2012 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., drilling contracts for onshore and offshore rigs in various countries, and oil and/or natural gas transportation contracts in the U.S. and Western Canada. The leases call for future monthly net lease payments through 2014 at Thunder Hawk, through 2016 at West Patricia and Azurite and through 2023 at Kikeh. The U.K. and U.S. fueling stations require monthly payments mostly over the next 20 years. The U.S. and Western Canada transportation contracts require minimum monthly payments through 2023. Future required minimum annual payments under these arrangements are included in the contractual obligation table shown on the preceding page.

In November 2012, the field's operator executed a 25 year lease for a semi-floating production system at the Kakap-Gumusut field offshore Sabah, Malaysia. This lease will become effective when the construction of the system is certified as complete, which is expected to occur in 2013. Although not legally liable under the lease until completion of construction and sail away, the Company has included the expected lease obligations for this production system 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 2013, West Texas Intermediate crude oil traded in a band between $92 and $98 per barrel. NYMEX natural gas traded in a band of $3.10 to $3.55 per MMBTU during this same time. U.S. retail marketing margins in January 2012 were squeezed by higher wholesale gasoline prices and weaker seasonal driver demand for motor fuel products 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 2013 was prepared during the fall of 2012 and based on this budget capital expenditures in 2013 are expected to be comparable to 2012 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 2013 budget, but North American natural gas prices have generally trailed the budgeted prices. Capital expenditures in 2013 are projected to total approximately $4.3 billion. Of this amount, $4.1 billion or about 95%, is allocated for the exploration and production program. Geographically, E&P capital is spread approximately as follows: 41% for the United States, 38% for Malaysia, 13% for Canada and 8% for all other areas. Spending in the U.S. is primarily associated with development and exploration programs in the Eagle Ford Shale area of South Texas. In Malaysia, the majority of the spending is for continued development of the Kikeh, Kakap and Siakap fields in Block K and oil development projects offshore Sarawak in Blocks SK 309 and SK 311. Canadian spending is primarily related to continued development of the Seal heavy oil area and Syncrude. Refining and marketing expenditures in 2013 are budgeted at about $220 million, or 5% of the Company total, with the bulk of this spending allocated to construction of additional U.S. retail gasoline stations. Capital and other expenditures will be routinely reviewed during 2013 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 2013 using operating cash flow, but will supplement funding where necessary using borrowings under available credit facilities. The Company's 2013 budget calls for borrowings of long-term debt during the year to fund a portion of the capital program. If oil and/or natural gas prices weaken, actual cash flow generated from operations could be reduced such that higher than anticipated borrowings might be required during the year to maintain funding of the Company's ongoing development projects. Additionally, the 2013 budget assumes further share repurchases under the previously announced share buyback program of up to $1.0 billion. The level of these share repurchases is expected to influence the amount of borrowings under credit facilities during 2013.

The Company currently expects production in 2013 to average about 200,000 barrels of oil equivalent per day, a 3% increase compared to 2012. A key assumption in projecting the level of 2013 Company production is the anticipated ramp up of crude oil and natural gas production in the Eagle Ford Shale area of South Texas, where a major drilling and completion operation is ongoing with ten rigs in use. Another key factor in meeting 2013 production targets is the rate of decline of natural gas wells at the Tupper area in Western Canada. The Company significantly reduced development drilling operations in this area in 2012 and early 2013 due to depressed prices for Canadian natural gas production. Due to the drilling cut back, natural gas production in the Tupper area will decline in 2013. Other key assumptions necessary to achieve the anticipated 2013 production levels include continued reliability of production at significant operations such as Kikeh, Syncrude, Hibernia and Terra Nova and the continued demand for natural gas from our offshore Malaysia fields.

The Company's 2013 budget anticipates an increase for overall hydrocarbon extraction costs by about $5.00 on a barrel of oil equivalent basis. Production costs in 2013 are projected to increase due to expected higher costs for synthetic oil operations at Syncrude caused by more spend on environmental and other regulatory matters, plus an unfavorable effect from a lower mix of Tupper area gas production, which is historically near the lowest cost per barrel equivalent produced by the Company. The overall per-unit depreciation rate for oil and gas operations is anticipated to rise in 2013 due to ongoing capital development costs at Kikeh, the Seal heavy oil area and Terra Nova. Additionally, there is an unfavorable effect on the overall depreciation rate in 2013 from a lower mix of natural gas production in the Tupper area of Canada.

The Company has announced that it plans to exit the U.K. refining and marketing business. The sale process for this U.K. R&M business continues to progress in early 2013. In 2012, the Company announced its intention to separate its U.S. downstream operations into a stand-alone publicly owned company. At the present time, this separation is expected to be completed in 2013. The Company also announced in 2012 that it would sell its U.K. oil and gas production assets; the sales are expected to be completed in early 2013. Further, the Company announced a stock repurchase program of up to $1.0 billion. Through year-end 2012, the Company had funded a $250 million accelerated share repurchase program with a major financial institution.

After the anticipated separation of the U.S. downstream subsidiary from Murphy Oil Corporation during 2013, and the desired sale of the U.K. downstream business, the Company is expected to be fundamentally different. The Company will have significantly lower sales revenue as the U.S. and U.K. downstream businesses generated about 84% of Murphy's consolidated revenue in 2012. For the year of 2012, the combined U.S. and U.K. downstream businesses generated about 15% of operating income from continuing operations before considering unallocated corporate net costs. Also, the two downstream businesses made up about 85% of the Company's workforce at year-end 2012. The Company also anticipates that without these downstream operations, it may no longer qualify as a member of the Fortune 500 group of companies. Murphy Oil is anticipated to be an independent oil and gas company in the future and will not have a significant refining and marketing business as a diversification to its oil and gas business. This decrease in size and change in diversification could impact its credit rating, and could, although not expected to, impact its ability to repay long-term debt obligations when due.

Forward-Looking Statements

This Form 10-K contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. These statements, which express management's current views concerning future events or results, are subject to inherent risks and uncertainties. Factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements include, but are not limited to, the volatility and level of crude oil and natural gas prices, the level and success rate of our exploration programs, our ability to maintain production rates and replace reserves, customer demand for our products, adverse foreign exchange movements, political and regulatory instability, and uncontrollable natural hazards. Factors that could cause the forecasted separation of its U.S. downstream business, as discussed in this Form 10-K, not to occur include, but are not limited to, a failure to obtain necessary regulatory approvals, a failure to obtain assurances of anticipated tax treatment, a deterioration in the business or prospects of Murphy or its U.S. downstream subsidiary, adverse developments in Murphy or its U.S. downstream subsidiary's markets, and adverse developments in the U.S. or global capital markets, credit markets or economies generally. Additionally, the Company may be unable to sell its U.K. downstream business as it desires to do because it may fail to execute a sale of these operations on acceptable terms. For further discussion of risk factors, see Item 1A. Risk Factors, which begins on page 17 of this Annual Report on Form 10-K. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

As described in Note K to the consolidated financial statements, there were short-term commodity derivative contracts in place at December 31, 2012 to hedge the purchase price of corn and the sales prices of wet and dried distillers grain at the Company's ethanol production facilities in Hankinson, North Dakota, and Hereford, Texas. A 10% increase in the respective benchmark price of the commodities underlying these derivative contracts would have decreased the recorded net asset associated with these derivative contracts by approximately $0.5 million, while a 10% decrease would have increased the recorded net asset 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.

Also as described in Note K, there were short-term derivative foreign exchange contracts in place at December 31, 2012 to hedge the value of U.S. dollar based receivables against the Canadian dollar. A 10% strengthening of the U.S. dollar against the Canadian dollar would have increased the recorded net liability associated with these contracts by approximately $14.0 million, while a 10% weakening of the U.S. dollar would have reduced the recorded net liability by approximately $17.1 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.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages F-1 through F-55, which follow page 64 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, 2012, the principal executive officer and principal financial officer of Murphy Oil Corporation have concluded that the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective to ensure that the information required to be disclosed by Murphy Oil Corporation in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Murphy's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Management has conducted an evaluation of the effectiveness of the Company's internal control over financial reporting based on the criteria set forth in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2012. Management's report is included on page F-1 of this Form 10-K report. KPMG LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2012 and their report is included on page F-3 of this Form 10-K report.

There were no changes in the Company's internal controls over financial reporting that occurred during the fourth quarter of 2012 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. OTHER INFORMATION

None

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Certain information regarding executive officers of the Company is included on pages 22 and 23 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 8, 2013 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 8, 2013 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 8, 2013 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 8, 2013 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 8, 2013 under the caption "Audit Committee Report."

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.
Report of Management – Consolidated Financial Statements	F-1
Report of Management – Internal Control Over Financial Reporting	F-1
Report of Independent Registered Public Accounting Firm	F-2
Report of Independent Registered Public Accounting Firm	F-3
Consolidated Balance Sheets	F-4
Consolidated Statements of Income	F-5
Consolidated Statements of Comprehensive Income	F-6
Consolidated Statements of Cash Flows	F-7
Consolidated Statements of Stockholders' Equity	F-8
Notes to Consolidated Financial Statements	F-9
Supplemental Oil and Gas Information (unaudited)	F-46
Supplemental Quarterly Information (unaudited)	F-55

2. Financial Statement Schedules

Schedule II – Valuation Accounts and Reserves	F-56

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 April 3, 2012	Exhibit 3.2 of Murphy's Form 8-K report filed April 5, 2012
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.	

Exhibit No.		Incorporated by Reference to
4.1	Form of Indenture and Form of Supplemental Indenture between Murphy Oil Corporation and SunTrust Bank as Trustee	Exhibit 4.2 of Murphy's Form 10-K report for the year ended December 31, 2009
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	
10.4	2008 Stock Plan for Non-Employee Directors, as approved by shareholders on May 14, 2008	Form S-8 report filed February 5, 2009
10.5	2012 Long-Term Incentive Plan	Exhibit A of Murphy's definitive proxy statement (Definitive 14A) dated March 29, 2012
10.6	Letter Agreement dated as of June 20, 2012 between the Company and David M. Wood	Exhibit 10.1 of Murphy's Form 8-K report filed June 21, 2012
*12.1	Computation of Ratio of Earnings to Fixed Charges	
*13	2012 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.	
*23.3	Consent of McDaniel & Associates Consultants Ltd.	
*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 63
99.1	Form of employee stock option	Exhibits 99.1 and 99.2 of Murphy's Form 10-Q report filed August 6, 2012
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 unit award	Exhibit 99.5 of Murphy's Form 10-K report for the year ended December 31, 2008
99.5	Form of phantom unit award	Exhibit 99.1 of Murphy's Form 10-Q report filed November 6, 2012

Exhibit No.		Incorporated by Reference to
*99.6	Form of stock appreciation right ("SAR")	
*99.7	Form of performance-based restricted stock unit-cash grant agreement	
*99.8	Form of performance-based units grant agreement	
*99.9	Report of McDaniel & Associates Consultants Ltd.	
*99.10	Report of Ryder Scott Company, L.P.	
99.11	Report of Ryder Scott Company, L.P.	Exhibit 99.6 of Murphy's Form 10-K report for the year ended December 31, 2011
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.

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 STEVEN A. COSSÉ Date: February 28, 2013

Steven A. Cossé, President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 28, 2013 by the following persons on behalf of the registrant and in the capacities indicated.

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

REPORT OF MANAGEMENT – CONSOLIDATED FINANCIAL STATEMENTS

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

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

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

REPORT OF MANAGEMENT – INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Management has conducted an evaluation of the effectiveness of the Company's internal control over financial reporting based on the criteria set forth in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2012.

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

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, 2012 and 2011, 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, 2012. 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, 2012 and 2011, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2012, 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, 2012, 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, 2013 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 28, 2013

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, 2012, 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, 2012, 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, 2012 and 2011, 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, 2012, and our report dated February 28, 2013 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 28, 2013

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

December 31 *(Thousands of dollars)*	**2012**	2011
Assets		
Current assets		
Cash and cash equivalents	**$ 947,316**	513,873
Canadian government securities with maturities greater than 90 days at the date of acquisition	**115,603**	532,093
Accounts receivable, less allowance for doubtful accounts of $6,697 in 2012 and $7,892 in 2011	**1,853,364**	1,554,184
Inventories, at lower of cost or market		
Crude oil and blend stocks	**226,541**	189,320
Finished products	**266,307**	254,880
Materials and supplies	**259,462**	222,438
Prepaid expenses	**335,831**	93,397
Deferred income taxes	**89,040**	87,486
Assets held for sale	**15,119**	0
Total current assets	**4,108,583**	3,447,671
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $8,138,587 in 2012 and $6,861,494 in 2011	**13,011,606**	10,475,149
Goodwill	**43,103**	41,863
Deferred charges and other assets	**151,183**	173,455
Assets held for sale	**208,168**	0
Total assets	**$17,522,643**	14,138,138
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long-term debt	**$ 46**	350,005
Accounts payable	**2,803,268**	1,941,008
Income taxes payable	**219,847**	201,784
Other taxes payable	**172,962**	169,535
Other accrued liabilities	**162,876**	140,024
Deferred income taxes	**2,611**	22,572
Liabilities associated with assets held for sale	**47,471**	0
Total current liabilities	**3,409,081**	2,824,928
Long-term debt	**2,245,201**	249,553
Deferred income taxes	**1,544,336**	1,230,111
Asset retirement obligations	**724,273**	615,545
Deferred credits and other liabilities	**516,540**	439,604
Liabilities associated with assets held for sale	**141,177**	0
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, 2012 and 2011, issued 194,616,470 shares at December 31, 2012 and 193,909,200 shares at December 31, 2011	**194,616**	193,909
Capital in excess of par value	**873,934**	817,974
Retained earnings	**7,717,389**	7,460,942
Accumulated other comprehensive income	**408,901**	310,420
Treasury stock	**(252,805)**	(4,848)
Total stockholders' equity	**8,942,035**	8,778,397
Total liabilities and stockholders' equity	**$17,522,643**	14,138,138

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(Thousands of dollars except per share amounts)*	**2012**	2011*	2010*
Revenues			
Sales and other operating revenues	**$ 28,616,331**	27,582,423	20,092,836
Gain (loss) on sale of assets	**(1,258)**	22,679	884
Interest and other income (loss)	**10,973**	33,019	(57,570)
Total revenues	**28,626,046**	27,638,121	20,036,150
Costs and Expenses			
Crude oil and product purchases	**22,449,306**	21,875,297	15,351,318
Operating expenses	**2,127,503**	1,964,891	1,651,623
Exploration expenses, including undeveloped lease amortization	**380,924**	489,346	276,089
Selling and general expenses	**354,493**	297,520	256,471
Depreciation, depletion and amortization	**1,375,577**	1,079,750	1,092,107
Impairment of properties	**260,988**	368,600	0
Accretion of asset retirement obligations	**39,341**	34,724	29,580
Redetermination of Terra Nova working interest	**0**	(5,351)	18,582
Interest expense	**54,105**	55,831	53,172
Interest capitalized	**(39,173)**	(15,131)	(18,444)
Total costs and expenses	**27,003,064**	26,145,477	18,710,498
Income from continuing operations before income taxes	**1,622,982**	1,492,644	1,325,652
Income tax expense	**658,936**	763,173	576,572
Income from continuing operations	**964,046**	729,471	749,080
Income from discontinued operations, net of income taxes	**6,830**	143,231	49,001
Net Income	**$ 970,876**	872,702	798,081
Income per Common Share – Basic			
Income from continuing operations	**$ 4.97**	3.77	3.90
Income from discontinued operations	**0.04**	0.74	0.26
Net Income – Basic	**$ 5.01**	4.51	4.16
Income per Common Share – Diluted			
Income from continuing operations	**$ 4.95**	3.75	3.88
Income from discontinued operations	**0.04**	0.74	0.25
Net Income – Diluted	**$ 4.99**	4.49	4.13
Average Common shares outstanding – basic	**193,902,335**	193,409,621	191,830,357
Average Common shares outstanding – diluted	**194,668,737**	194,512,402	193,157,814

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

* Reclassified to conform to current presentation.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(Thousands of dollars)*	**2012**	2011	2010
Net income	**$ 970,876**	872,702	798,081
Other comprehensive income (loss), net of tax			
Net gain (loss) from foreign currency translation	**117,331**	(91,247)	165,940
Retirement and postretirement benefit plan adjustments	**(17,650)**	(30,909)	(3,699)
Deferred loss on interest rate hedges:			
Increase in deferred loss associated with contract revaluation and settlement	**(2,407)**	(16,852)	0
Amount of loss reclassified to interest expense in consolidated statements of income	**1,207**	0	0
Other comprehensive income (loss)	**98,481**	(139,008)	162,241
Comprehensive Income	**$1,069,357**	733,694	960,322

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(Thousands of dollars)*	2012	2011[1]	2010[1]
Operating Activities			
Net income	**$ 970,876**	872,702	798,081
Adjustments to reconcile net income to net cash provided by operating activities			
Income from discontinued operations	**(6,830)**	(143,231)	(49,001)
Depreciation, depletion and amortization	**1,375,577**	1,079,750	1,092,107
Impairment of long-lived assets	**260,988**	368,600	0
Amortization of deferred major repair costs	**22,818**	23,076	15,561
Expenditures for asset retirements	**(40,434)**	(21,490)	(36,496)
Dry hole costs	**181,924**	250,954	74,891
Amortization of undeveloped leases	**129,750**	118,211	108,026
Accretion of asset retirement obligations	**39,341**	34,724	29,580
Deferred and noncurrent income tax charges	**316,587**	156,983	146,583
Pretax (gains) losses from disposition of assets	**1,258**	(22,679)	(884)
Net decrease (increase) in noncash operating working capital	**(401,103)**	(825,705)	639,612
Other operating activities – net	**144,388**	67,955	151,012
Net cash provided by continuing operations	**2,995,140**	1,959,850	2,969,072
Net cash provided by discontinued operations	**61,141**	185,535	159,486
Net cash provided by operating activities	**3,056,281**	2,145,385	3,128,558
Investing Activities			
Property additions and dry hole costs	**(3,674,621)**	(2,603,158)	(2,188,517)
Acquisition of ethanol plant	**0**	0	(40,000)
Proceeds from sale of property, plant and equipment	**569**	27,776	2,189
Expenditures for major repairs	**(12,790)**	(5,409)	(61,387)
Purchase of investment securities[2]	**(1,619,308)**	(1,689,087)	(2,388,720)
Proceeds from maturity of investment securities[2]	**2,035,798**	1,773,552	2,551,187
Other investing activities – net	**11,086**	8,014	(38,157)
Investing activities of discontinued operations			
Sales proceeds	**0**	950,010	0
Other	**(58,156)**	(76,052)	(165,407)
Net cash required by investing activities	**(3,317,422)**	(1,614,354)	(2,328,812)
Financing Activities			
Additions to long-term debt	**1,995,467**	0	0
Repayments of debt	**(350,000)**	(340,041)	(332,038)
Repayment of nonrecourse debt of a subsidiary	**0**	0	(82,000)
Purchase of treasury stock	**(250,000)**	0	0
Proceeds from exercise of stock options and employee stock purchase plans	**12,324**	15,551	42,995
Excess tax benefits related to exercise of stock options	**2,647**	4,838	11,672
Withholding tax on stock-based incentive awards	**(3,341)**	(8,014)	(5,170)
Issue cost of debt facility	**(6,959)**	(7,905)	0
Cash dividends paid	**(714,429)**	(212,752)	(201,405)
Net cash provided (required) by financing activities	**685,709**	(548,323)	(565,946)
Effect of exchange rate changes on cash and cash equivalents	**8,875**	(4,660)	881
Net increase (decrease) in cash and cash equivalents	**433,443**	(21,952)	234,681
Cash and cash equivalents at January 1	**513,873**	535,825	301,144
Cash and cash equivalents at December 31	**$ 947,316**	513,873	535,825

1 Reclassified to conform to current presentation.

2 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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

Years Ended December 31 *(Thousands of dollars)*	**2012**	2011	2010
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	**0**	0	0
Common Stock – par $1.00, authorized 450,000,000 shares at December 31, 2012, 2011 and 2010, issued 194,616,470 shares at December 31, 2012, 193,909,200 shares at December 31, 2011 and 193,293,526 shares at December 31, 2010			
Balance at beginning of year	**$ 193,909**	193,294	191,798
Exercise of stock options	**483**	615	1,496
Awarded restricted stock	**224**	0	0
Balance at end of year	**194,616**	193,909	193,294
Capital in Excess of Par Value			
Balance at beginning of year	**817,974**	767,762	680,509
Exercise of stock options, including income tax benefits	**12,717**	21,774	54,887
Restricted stock transactions and other	**(5,257)**	(15,119)	(9,688)
Stock-based compensation	**46,584**	42,492	40,842
Sale of stock under employee stock purchase plans	**1,916**	1,065	1,212
Balance at end of year	**873,934**	817,974	767,762
Retained Earnings			
Balance at beginning of year	**7,460,942**	6,800,992	6,204,316
Net income for the year	**970,876**	872,702	798,081
Cash dividends – $3.675 per share in 2012, $1.10 per share in 2011 and $1.05 per share in 2010	**(714,429)**	(212,752)	(201,405)
Balance at end of year	**7,717,389**	7,460,942	6,800,992
Accumulated Other Comprehensive Income			
Balance at beginning of year	**310,420**	449,428	287,187
Foreign currency translation gains (losses), net of income taxes	**117,331**	(91,247)	165,940
Retirement and postretirement benefit plan adjustments, net of income taxes	**(17,650)**	(30,909)	(3,699)
Change in deferred loss on interest rate hedges, net of income taxes	**(1,200)**	(16,852)	0
Balance at end of year	**408,901**	310,420	449,428
Treasury Stock			
Balance at beginning of year	**(4,848)**	(11,926)	(17,784)
Purchase of treasury shares	**(250,000)**	0	0
Sale of stock under employee stock purchase plans	**2,043**	870	1,295
Awarded restricted stock, net of forfeitures	**0**	6,208	4,563
Balance at end of year – 3,975,153 shares of Common Stock in 2012, 185,992 shares of Common Stock in 2011 and 457,518 shares in 2010	**(252,805)**	(4,848)	(11,926)
Total Stockholders' Equity	**$8,942,035**	8,778,397	8,199,550

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

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 and to separate its U.S. downstream subsidiary into an independent publicly held company. The Company has also announced that it has entered into agreements to sell its U.K. oil and gas 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. Title transfer for bulk motor fuel products generally occurs at pipeline custody points or upon truck loading at product terminals. Merchandise revenues are recorded at the point of sale. Rebates from vendors are recognized as a reduction of cost of goods sold when the initiating transaction occurs. Revenues from the production of oil and natural gas properties in which Murphy shares an undivided interest with other producers are recognized based on the actual volumes sold by the Company during the period. Natural gas imbalances occur when the Company's actual gas sales volumes differ from its entitlement under existing working interests. The Company records a liability for gas imbalances when it has sold more than its working interest of gas production and the estimated remaining reserves make it doubtful that partners can recoup their share of production from the field. At December 31, 2012 and 2011, 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 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, 2012, the Company owned Canadian government securities with maturities greater than 90 days at date of acquisition that had a carrying value of $115,603,000.

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.

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 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 the Milford Haven, Wales refinery are scheduled at four to five year intervals. Turnarounds for coking units at Syncrude Canada Ltd. are scheduled at intervals of two to three years. Turnaround work associated with various other less significant units at Milford Haven and Syncrude varies depending on operating requirements and events. Murphy defers turnaround costs incurred and amortizes such costs 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 2012 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, 2012. 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 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. oil and gas 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 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 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 units and other stock-based compensation 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 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 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.

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

In September 2011, the Financial Accounting Standards Board (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 was effective for annual and interim goodwill impairment tests performed in fiscal years beginning in 2012. The adoption of this standard in 2012 did not have a significant effect on the Company's 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 was effective for the Company beginning in the first quarter of 2012. The adoption of this guidance in 2012 did not 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.

Recent Accounting and Reporting Rules

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

Note C – Discontinued Operations

During the third quarter 2012, Murphy's Board of Directors authorized management to sell the Company's exploration and production (upstream) operations in the United Kingdom. Beginning in 2012, the Company has accounted for U.K. upstream operations as discontinued operations for all periods presented, including a reclassification of all prior years' results for these operations to discontinued operations. The U.K. upstream operations were formerly reported as a separate segment within the Company's exploration and production business. The Company currently expects to complete the sale of these U.K. operations in early 2013.

Assets and liabilities presented in the December 31, 2012 Consolidated Balance Sheet as held for sale related to the U.K. exploration and production operations were as follows:

(Thousands of dollars)	
Current Assets:	
Accounts receivable	$ 10,143
Inventories and other	4,976
	$ 15,119
Noncurrent Assets:	
Property, plant and equipment – net	$205,746
Other	2,422
	$208,168
Current liabilities:	
Accounts payable	$ 27,578
Income taxes payable	19,893
	$ 47,471
Noncurrent liabilities:	
Deferred income taxes payable	$ 87,893
Asset retirement obligation	53,284
	$141,177

In July 2010, the Company announced that it planned to exit the U.S. refining business. On September 30, 2011, the Company sold the Superior, Wisconsin refinery and related assets for $214,000,000, plus certain capital expenditures between July 25, 2011, and the date of closing and the fair value of all associated hydrocarbon inventories at these locations. On October 1, 2011, the Company sold its Meraux, Louisiana refinery and related assets for $325,000,000, plus the fair value of associated hydrocarbon inventories. The Company has accounted for the results of the Superior, Wisconsin and Meraux, Louisiana refineries and associated marketing assets as discontinued operations. The after-tax gain in 2011 from disposal of the two refineries netted to $18,724,000, made up of a gain on the Superior refinery (including associated inventories) of $77,585,000 and a loss on the Meraux refinery (including associated inventories) of $58,861,000. The gain on disposal 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 primarily under the last-in, first-out cost method. The U.S. refineries sold were formerly reported in the U.S. manufacturing segment.

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

(Thousands of dollars)	**2012**	2011	2010
Revenues	**$150,304**	3,808,217	3,308,921
Income from operations before income taxes	**$ 75,074**	246,570	88,579
Gain on sale before income taxes	**0**	12,684	0
Total income from discontinued operations before taxes	**75,074**	259,254	88,579
Provision for income taxes	**68,244**	116,023	39,578
Income from discontinued operations	**$ 6,830**	143,231	49,001

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

Note D – Property, Plant and Equipment

(Thousands of dollars)	**December 31, 2012**		December 31, 2011	
	Cost	**Net**	Cost	Net
Exploration and production[1]	**$18,408,904**	**11,294,933[2]**	14,766,637	8,730,124[2]
Refining and marketing	**2,619,844**	**1,661,081**	2,456,822	1,688,709
Corporate and other	**121,445**	**55,592**	113,184	56,316
	$21,150,193	**13,011,606**	17,336,643	10,475,149
[1] Includes mineral rights as follows:	**$ 1,051,153**	**556,399**	1,078,770	619,950

[2] Includes $26,611 in 2012 and $21,154 in 2011 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, 2012, 2011 and 2010, the Company had total capitalized drilling costs pending the determination of proved reserves of $445,697,000, $556,412,000 and $497,765,000, respectively. The following table reflects the net changes in capitalized exploratory well costs during the three-year period ended December 31, 2012.

(Thousands of dollars)	**2012**	2011	2010
Beginning balance at January 1	**$ 556,412**	497,765	369,862
Additions to capitalized exploratory well costs pending the determination of proved reserves	**135,849**	86,035	137,403
Reclassifications to proved properties based on the determination of proved reserves	**(165,377)**	0	0
Capitalized exploratory well costs charged to expense or sold	**(81,187)**	(27,388)	(9,500)
Ending balance at December 31	**$ 445,697**	556,412	497,765

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.

	2012			**2011**			**2010**		
(Thousands of dollars)	**Amount**	**No. of Wells**	**No. of Projects**	Amount	No. of Wells	No. of Projects	Amount	No. of Wells	No. of Projects
Aging of capitalized well costs:									
Zero to one year	**$ 59,833**	**7**	**2**	$ 69,757	11	5	$135,494	15	4
One to two years	**18,335**	**2**	**3**	143,611	15	3	115,418	10	4
Two to three years	**83,314**	**9**	**4**	101,696	9	2	42,571	3	3
Three years or more	**284,215**	**26**	**6**	241,348	33	6	204,282	31	4
	$445,697	**44**	**15**	$556,412	68	16	$497,765	59	15

Of the $385,864,000 of exploratory well costs capitalized more than one year at December 31, 2012, $270,093,000 is in Malaysia and $115,771,000 is in the U.S. 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. The capitalized well costs charged to expense in 2012 included a suspended well in the northern block of the Republic of the Congo that was written off following unsuccessful wildcat drilling in 2012 at a nearby prospect, two suspended wells offshore Sarawak Malaysia that were written off following a government denial of a request to delay the timing of an oil development project, and a well drilled in the Gulf of Mexico in 2010 that the owners decided not to develop. The capitalized well costs expensed in 2011 related to exploration costs offshore Republic of the Congo and Brunei. The costs in Republic of the Congo were written off following an impairment charge at the nearby Azurite field, and the Brunei costs were written off based on unsuccessful wells drilled in the area in late 2011.

At year-end 2012, Murphy determined that the Azurite field, offshore Republic of the Congo, was impaired due to removal of all proved oil reserves after an unsuccessful redrill of a key well in the field. The impairment charge in 2012 totaled $200,000,000 and included a write-off of the remaining book value of the Azurite field plus other anticipated losses related to operations of the field. At year-end 2011, an impairment charge of $368,600,000 was recorded to reduce the carrying value of the Azurite field to fair value. The Company determined that a downward revision of proved oil reserves for Azurite was necessary at year-end 2011. 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. Fair value was determined each year at Azurite using a discounted cash flow model based on certain key assumptions, including future estimated net production levels, future estimated oil prices for the field based on year-end futures prices, and future estimated operating and capital expenditures. The 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.

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

In 2012, the Company announced that its Board of Directors had approved a plan to separate its U.S. downstream subsidiary into a separate publicly owned company. 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.S. and U.K. refining and marketing segments in Note T. The separation of the U.S. downstream subsidiary is expected to be completed during 2013. The sale process for the U.K. downstream assets continues in 2013. Based on current market conditions, it is possible that the Company could incur a loss when the U.K. downstream assets are sold. If the separation of the U.S. downstream subsidiary and the sale of the U.K. downstream assets continue to progress, the results of these operations are likely to be presented as discontinued operations in future periods when the operations no longer qualify as continuing operations under U.S. generally accepted accounting principles.

Note E – Financing Arrangements

At December 31, 2012, the Company had a $1.5 billion committed credit facility with a major banking consortium that expires in June 2016. Borrowings under this facility bear interest at 1.25% above LIBOR based on the Company's current credit rating as of December 31, 2012. In addition, facility fees of 0.25% are charged on the full $1.5 billion commitment. At December 31, 2012, the Company had no borrowings under this committed facility. At December 31, 2012, the Company also had no borrowings under uncommitted credit lines that had estimated total borrowing capacity of approximately $320,000,000. 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 October 2015.

Note F – Long-term Debt

(Thousands of dollars)	December 31 2012	December 31 2011
Notes payable		
2.50% notes, due 2017, net of unamortized discount of $76 at December 31, 2012	**$ 549,924**	0
3.70% notes, due 2022, net of unamortized discount of $2,415 at December 31, 2012	**597,585**	0
4.00% notes, due 2022, net of unamortized discount of $1,004 at December 31, 2012	**498,996**	0
7.05% notes, due 2029, net of unamortized discount of $1,523 at December 31, 2012	**248,477**	248,384
5.125% notes, due 2042, net of unamortized discount of $904 at December 31, 2012	**349,096**	0
6.375% notes, due 2012, net of unamortized discount of $38 at December 31, 2011	**0**	349,962
Other, 6%, due through 2028	**1,169**	1,212
Total debt including current maturities	**2,245,247**	599,558
Current maturities	**(46)**	(350,005)
Total long-term debt	**$2,245,201**	249,553

Future amounts repayable under debt agreements are: $46,000 in 2013, $48,000 in 2014, $51,000 in 2015, $55,000 in 2016, $549,982,000 in 2017 and $1,695,065,000 thereafter.

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 G – Asset Retirement Obligations

The majority of the asset retirement obligations liabilities (ARO) recognized by the Company at December 31, 2012 and 2011 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 2012 and 2011 is shown in the following table.

(Thousands of dollars)	**2012**	2011
Balance at beginning of year	**$615,545**	555,248
Accretion expense	**39,341**	37,701[1]
Liabilities incurred	**184,439**	51,858
Revision of previous estimates	**10,468**	7,608
Liabilities settled	**(40,434)**	(32,088)[2]
U.K. amounts reclassified to liabilities associated with assets held for sale	**(64,355)**	0
Changes due to translation of foreign currencies	**6,579**	(4,782)
Balance at end of year	**751,583**	615,545
Current portion of liability at end of year	**(27,310)**[3]	0
Noncurrent portion of liability at end of year	**$724,273**	615,545

1 Includes $2,977 reclassified to discontinued operations associated with U.K. oil and gas production operations.
2 Includes noncash settlements related to sale of assets in Spain in 2011.
3 Included in Other Accrued Liabilities on Consolidated Balance Sheet.

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

Note H – Income Taxes

The components of income from continuing operations before income taxes for each of the three years ended December 31, 2012 and income tax expense attributable thereto were as follows.

(Thousands of dollars)	**2012**	2011	2010
Income from continuing operations before income taxes			
United States	**$ 229,981**	440,753	188,588
Foreign	**1,393,001**	1,051,891	1,137,064
	$1,622,982	1,492,644	1,325,652
Income tax expense			
Federal – Current	**$ (181,003)**	99,451	110,142
Deferred	**156,856**	43,602	(40,981)
	(24,147)	143,053	69,161
State	**24,754**	30,372	15,486
Foreign – Current	**503,674**	465,150	303,808
Deferred	**154,655**	124,598	188,117
	658,329	589,748	491,925
Total	**$ 658,936**	763,173	576,572

Income tax benefits attributable to employee stock option transactions of $5,920,000 in 2012, $8,775,000 in 2011 and $15,896,000 in 2010 were included in Capital in Excess of Par Value within Stockholders' Equity in the Consolidated Balance Sheets.

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

(Thousands of dollars)	**2012**	2011	2010
Income tax expense based on the U.S. statutory tax rate	**$ 568,044**	522,425	463,978
Foreign income subject to foreign taxes at a rate different than the U.S. statutory rate	**5,542**	(1,945)	45,859
State income taxes, net of federal benefit	**16,090**	19,742	10,066
U.S. tax benefit on certain foreign exploration activities	**(108,077)**	0	0
Increase in deferred tax asset valuation allowance related to other foreign exploration expenditures	**87,558**	102,714	47,128
Impairment of Azurite field with no tax benefit	**70,000**	129,010	0
Malaysian tax benefits on prior year costs in Block P	**0**	(25,573)	0
Other, net	**19,779**	16,800	9,541
Total	**$ 658,936**	763,173	576,572

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2012 and 2011 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	**2012**	2011
Deferred tax assets		
Property and leasehold costs	**$ 658,588**	627,093
Liabilities for dismantlements	**78,100**	114,175
Postretirement and other employee benefits	**197,912**	164,044
Alternative minimum tax	**37,253**	0
Foreign tax credit carryforwards	**18,594**	21,368
Other deferred tax assets	**32,500**	38,341
Total gross deferred tax assets	**1,022,947**	965,021
Less valuation allowance	**(523,966)**	(445,842)
Net deferred tax assets	**498,981**	519,179
Deferred tax liabilities		
Property, plant and equipment	**(808,311)**	(851,330)
Accumulated depreciation, depletion and amortization	**(1,077,867)**	(754,295)
Other deferred tax liabilities	**(70,710)**	(78,751)
Total gross deferred tax liabilities	**(1,956,888)**	(1,684,376)
Net deferred tax liabilities	**$(1,457,907)**	(1,165,197)

In management's judgment, the net deferred tax assets in the preceding table will more likely than not be realized as reductions of future taxable income or by utilizing available tax planning strategies. The valuation allowance for deferred tax assets relates primarily to tax assets arising in foreign tax jurisdictions and foreign tax credit carryforwards. In the judgment of management at the present time, these tax assets are not likely to be realized. The foreign tax credit carryforwards expire in 2015 through 2022. The valuation allowance increased

$78,124,000 in 2012, 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, 2012, undistributed earnings of the Company's subsidiaries considered indefinitely invested were approximately $6,022,000,000. The unrecognized deferred tax liability is dependent on many factors including withholding taxes under current tax treaties and foreign tax credits and is estimated to be approximately $709,000,000. The Company does not consider undistributed earnings from certain other international operations to be indefinitely invested; however, any estimated tax liabilities upon repatriation of earnings from these international operations are expected to be offset with foreign tax credits. Although the Company does not foresee repatriating earnings considered indefinitely invested, under present law, it would incur a 5% withholding tax on any monies repatriated from Canada to the United States.

Uncertain Income Tax Positions

The FASB's rules for accounting for income tax uncertainties clarify the criteria for recognizing uncertain income tax benefits and require additional disclosures about uncertain tax positions. Under current rules the financial statement recognition of the benefit for a tax position is dependent upon the benefit being more likely than not to be sustainable upon audit by the applicable taxing authority. If this threshold is met, the tax benefit is then measured and recognized at the largest amount that is greater than 50 percent likely of being realized upon ultimate settlement. Liabilities associated with uncertain income tax positions are included in Deferred Credits and Other Liabilities in the Consolidated Balance Sheet. A reconciliation of the beginning and ending amount of the consolidated liability for unrecognized income tax benefits during the three years ended December 31, 2012 is shown in the following table.

(Thousands of dollars)	**2012**	2011	2010
Balance at January 1	**$18,857**	23,196	25,978
Additions for tax positions related to current year	**1,258**	1,294	1,225
Settlements due to lapse of time	**(3,504)**	(5,633)	(4,007)
Balance at December 31	**$16,611**	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, 2012 and 2011 for interest and penalties of $975,000 and $976,000, respectively, associated with uncertain tax positions. Income tax expense for the years ended December 31, 2012, 2011 and 2010 included (charges)/benefits for interest and penalties of $1,000, $34,000 and $(43,000), 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 2013 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 2013.

The Company's tax returns in multiple jurisdictions are subject to audit by taxing authorities. These audits often take years to complete and settle. Although the Company believes that recorded liabilities for unsettled issues are adequate, additional gains or losses could occur in future years from resolution of outstanding unsettled matters. As of December 31, 2012, the earliest years remaining open for audit and/or settlement in the Company's major taxing jurisdictions are as follows: United States – 2009; Canada – 2007; United Kingdom – 2011; and Malaysia – 2006.

Note I – Incentive Plans

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

At the Company's annual stockholders' meeting held on May 9, 2012, shareholders approved replacement of the 2007 Annual Incentive Plan (2007 Annual Plan) and the 2007 Long-Term Incentive Plan (2007 Long-Term Plan) with the 2012 Annual Incentive Plan (2012 Annual Plan) and 2012 Long-Term Incentive Plan (2012 Long-Term Plan), respectively. The new plans can be found in the Company's Definitive Proxy statement (Definitive 14A) dated March 29, 2012. All awards on or after May 9, 2012 will be made under the respective 2012 plans.

The 2012 Annual Plan and the 2007 Annual Plan authorize the Executive Compensation Committee (the Committee) to establish specific performance goals associated with annual cash awards that may be earned by officers, executives and certain other employees. Cash awards under the 2012 Annual Plan and 2007 Annual Plan are determined based on the Company's actual financial and operating results as measured against the performance goals established by the Committee. The 2012 Long-Term Plan and the 2007 Long-Term Plan authorize the Committee to make grants of the Company's Common Stock to employees. These grants may be in the form of stock options (nonqualified or incentive), stock appreciation rights (SAR), restricted stock, restricted stock units, performance units, performance shares, dividend equivalents and other stock-based incentives. The 2012 Long-Term Plan expires in 2022. A total of 8,700,000 shares are issuable during the life of the 2012 Long-Term Plan, with annual grants limited to 1% of Common shares outstanding; allowed shares not granted may be granted in future years. Based on awards made to date, approximately 8,472,500 shares remained available for grant under the 2012 Long-Term Plan at December 31, 2012. The Company also has a Stock Plan for Non-Employee Directors (Director Plan) that permits the issuance of restricted stock, restricted stock units and stock options or a combination thereof to the Company's Non-Employee Directors.

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

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

(Thousands of dollars)	**2012**	2011	2010
Compensation charged against income before income tax benefit	**$46,694**	43,272	41,992
Related income tax benefit recognized in income	**10,924**	13,053	12,169

As of December 31, 2012, there was $56,638,000 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, 2012, 2011 and 2010 was $12,324,000, $15,551,000 and $42,995,000, respectively. Total income tax benefits realized from tax deductions related to stock option exercises under share-based payment arrangements were $5,920,000, $8,775,000 and $15,896,000 for the years ended December 31, 2012, 2011 and 2010, respectively.

STOCK OPTIONS – The Committee fixes the option price of each option granted at no less than fair market value (FMV) on the date of the grant and fixes the option term at no more than seven years from such date. Each option granted to date under the 2012 Long-Term Plan and the 2007 Long-Term Plan has been nonqualified, with a term of seven years and an option price equal to FMV at date of grant. Under the 2012 Long-Term Plan and the 2007 Long-Term Plan, one-half of each grant is generally exercisable after two years and the remainder after three years. Under the Director 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 based on the assumptions noted in the following table. Expected volatility is based on historical volatility of the Company's stock and implied volatility on publicly traded at-the-money options on the Company's stock. The Company estimates the expected term of the options granted based on historical option exercise patterns and considers certain groups of employees exhibiting different behavior. The risk-free interest rate for periods within the expected term of the option is based on the U.S. Treasury yield curve in effect at the time of grant.

	2012	2011	2010
Fair value per option grant	**$12.37 – $17.74**	$20.34	$18.75
Assumptions			
Dividend yield	**1.80% – 2.27%**	1.80%	1.80%
Expected volatility	**39.00% – 39.62%**	37.00%	43.00%
Risk-free interest rate	**0.55% – 0.77%**	2.10%	2.52%
Expected life	**4.00 yrs. – 5.20 yrs.**	5.10 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, 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
Granted at FMV	**1,870,500**	**57.96**
Exercised	**(823,855)**	**38.37**
Forfeited	**(573,514)**	**60.43**
Outstanding at December 31, 2012	**5,907,359**	**57.89**
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
Exercisable at December 31, 2012	**2,474,636**	**54.43**

Additional information about stock options outstanding at December 31, 2012 is shown below.

	Options Outstanding			Options Exercisable		
Range of Exercise Prices per Option	No. of Options	Avg. Life Remaining in Years	Aggregate Intrinsic Value	No. of Options	Avg. Life Remaining in Years	Aggregate Intrinsic Value
$21.17 to $23.58	70,750	0.1	$ 2,614,000	70,750	0.1	$ 2,614,000
$30.30 to $45.70	924,910	3.5	14,327,000	697,410	2.6	11,176,000
$51.07 to $57.32	1,643,097	2.9	11,084,000	1,071,476	2.3	7,252,000
$59.66 to $72.75	3,268,602	4.9	0	635,000	1.9	0
	5,907,359	4.0	$28,025,000	2,474,636	2.2	$21,042,000

The total intrinsic value of options exercised during 2012, 2011 and 2010 was $17,197,000, $28,145,000 and $49,929,000, respectively. Intrinsic value is the excess of the market price of stock at date of exercise over the exercise price received by the Company upon exercise. Aggregate intrinsic value is nil when the exercise price of the stock option exceeds the market price of the Company's Common stock. In February 2013, the Committee reduced the exercise price of all outstanding stock options by $2.50 per share to reflect the impact of the special dividend of the same amount paid in December 2012. The exercise prices in the tables above do not reflect this $2.50 reduction in exercise price approved in 2013. The income statement effect of this reduced exercise price will be reflected in 2013 and future years.

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 through 2012.

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

(Number of shares or share units)	**2012**	2011	2010
Balance at beginning of year	**1,174,492**	1,023,492	872,027
Granted	**653,355**	521,423	449,100
Awarded	**(260,175)**	(309,656)	(252,551)
Forfeited	**(141,434)**	(60,767)	(45,084)
Balance at end of year	**1,426,238**	1,174,492	1,023,492

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 2012, 2011 and 2010 are presented in the following table.

	2012	2011	2010
Fair value per share at grant date	**$54.90 – $63.64**	$38.94 – $64.89	$42.38 – $50.95
Assumptions			
Expected volatility	**37.00%**	51.00%	51.00%
Risk-free interest rate	**0.30%**	1.04%	1.41%
Stock beta	**0.913**	1.006	1.008
Expected life	**3.00 yrs.**	3.00 yrs.	3.00 yrs.

TIME-LAPSE RESTRICTED STOCK UNITS – Restricted stock units (RSU) have been granted to the Company's Non-Employee Directors under the Directors Plan. These awards vest on the third anniversary of the date of grant. The fair value of these awards was estimated based on the fair market value of the Company's stock on the date of grant, which was $59.33 per share in 2012, $52.66 per share in 2011 and $52.49 per share in 2010. Changes in time-lapse restricted stock units outstanding for each of the last three years are presented in the following table.

(Number of shares or share units)	**2012**	2011	2010
Balance at beginning of year	**116,724**	166,173	164,695
Granted	**42,256**	32,711	43,370
Vested and issued	**(44,980)**	(82,160)	(29,475)
Forfeited	**(15,523)**	0	(12,417)
Balance at end of year	**98,477**	116,724	166,173

PHANTOM UNITS – A total of 55,000 phantom units were granted to two Company executives during 2012. These awards will be settled in cash in 2015 based on the average of the high and low price for the Company's Common stock on the maturity dates. Total expense of $305,000 was recorded related to these phantom awards during 2012.

PERFORMANCE UNITS – The Company also awarded performance units in 2011 and 2012 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 $2,665,000 in 2012 and $871,000 in 2011.

EMPLOYEE STOCK PURCHASE PLAN (ESPP) – The Company has an ESPP under which the Company's Common Stock can be purchased by eligible U.S. and Canadian employees. Each quarter, an eligible employee may elect to withhold up to 10% of his or her salary to purchase shares of the Company's stock at the end of the quarter at a price equal to 90% of the fair value of the stock as of the first day of the quarter. The ESPP will terminate on the earlier of the date that employees have purchased all 980,000 authorized shares or June 30, 2017. Employee stock purchases under the ESPP were 24,418 shares at an average price of $48.54 per share in 2012, 28,555 shares at an average price of $55.28 per share in 2011 and 44,361 shares at $51.97 per share in 2010. At December 31, 2012, 302,961 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 $272,000 in 2012, $328,000 in 2011 and $357,000 in 2010. The fair value per share issued under the ESPP was approximately $7.30, $8.60 and $7.51 for the years ended December 31, 2012, 2011 and 2010, respectively.

SAVINGS-RELATED SHARE OPTION PLAN (SOP) – One of the Company's U.K. subsidiaries formerly provided a plan that allowed shares of the Company's Common stock to be purchased by eligible employees using payroll withholdings. An eligible employee could have elected to withhold from £5 to £250 per month to purchase shares of Company stock at a price equal to 90% of the fair value of the stock as of the date of grant. The SOP plan had a term of three years and employee withholdings were fixed over the life of the plan. At the end of the term of the SOP plan an employee received interest on withholdings and had six months to either use all or part of the withholdings plus credited interest to purchase shares of Company stock or receive a repayment of withholdings plus credited interest. The SOP expired in 2012. Compensation costs related to the SOP plan were estimated based on the value of the 10% discount and the fair value of the option that allowed the employee to receive a repayment of withholdings plus credited interest. The fair value per share of the SOP plans with holding periods that ended in August 2010, April 2011 and May 2012 were $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 $32,417,000, $33,035,000 and $25,171,000 was recorded in 2012, 2011 and 2010, respectively, for these plans.

Note J – Employee and Retiree Benefit Plans

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

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

The tables that follow provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets for the years ended December 31, 2012 and 2011 and a statement of the funded status as of December 31, 2012 and 2011.

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	**2012**	2011	**2012**	2011
Change in benefit obligation				
Obligation at January 1	**$ 629,568**	575,300	**114,962**	122,879
Service cost	**23,500**	22,406	**3,958**	4,547
Interest cost	**29,869**	30,785	**5,174**	6,141
Plan amendments	**0**	483	**0**	0
Participant contributions	**30**	35	**1,035**	1,049
Actuarial loss	**55,479**	66,010	**4,686**	4,791
Medicare Part D subsidy	**0**	0	**432**	555
Exchange rate changes	**7,125**	(2,109)	**14**	(11)
Benefits paid	**(30,217)**	(27,745)	**(6,127)**	(5,667)
Reduction due to sale of the Superior refinery	**0**	(23,021)	**0**	0
Special termination benefits	**6,177**	695	**0**	0
Curtailments	**0**	(13,271)	**0**	(19,322)
Obligation at December 31	**721,531**	629,568	**124,134**	114,962
Change in plan assets				
Fair value of plan assets at January 1	**404,350**	416,272	**0**	0
Actual return on plan assets	**41,674**	(1,415)	**0**	0
Employer contributions	**42,207**	38,357	**4,660**	4,063
Participant contributions	**30**	35	**1,035**	1,049
Medicare Part D subsidy	**0**	0	**432**	555
Exchange rate changes	**6,289**	(1,786)	**0**	0
Benefits paid	**(30,217)**	(27,745)	**(6,127)**	(5,667)
Distribution to acquirer of the Superior refinery	**0**	(18,720)	**0**	0
Other	**(787)**	(648)	**0**	0
Fair value of plan assets at December 31	**463,546**	404,350	**0**	0
Funded status and amounts recognized in the Consolidated Balance Sheets at December 31				
Deferred charges and other assets	**9,679**	10,621	**0**	0
Other accrued liabilities	**(5,556)**	(3,488)	**(5,646)**	(5,022)
Deferred credits and other liabilities	**(262,108)**	(232,351)	**(118,488)**	(109,940)
Funded status and net plan liability recognized at December 31	**$(257,985)**	(225,218)	**(124,134)**	(114,962)

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, 2012, amounts included in accumulated other comprehensive income (AOCI), before reduction for associated deferred income taxes, which have not been recognized in net periodic benefit expense are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
Net actuarial loss	**$(238,684)**	**(38,706)**
Prior service (cost) credit	**(3,987)**	**957**
Transitional asset (liability)	**1,062**	**(8)**
	$(241,609)	**(37,757)**

Amounts included in AOCI at December 31, 2012 that are expected to be amortized into net periodic benefit expense during 2013 are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
Net actuarial loss	**$(18,800)**	**(1,876)**
Prior service (cost) credit	**(1,195)**	**173**
Transitional asset (liability)	**529**	**(8)**
	$(19,466)	**(1,711)**

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

	Projected Benefit Obligations		Accumulated Benefit Obligations		Fair Value of Plan Assets	
(Thousands of dollars)	**2012**	2011	**2012**	2011	**2012**	2011
Funded qualified plans where accumulated benefit obligation exceeds fair value of plan assets	**$587,318**	513,444	**523,773**	459,556	**431,788**	374,360
Unfunded nonqualified and directors' plans where accumulated benefit obligation exceeds fair value of plan assets	**112,135**	96,754	**98,498**	82,642	**0**	0
Unfunded other postretirement plans	**124,134**	114,962	**124,134**	114,962	**0**	0

The table that follows provides the components of net periodic benefit expense for each of the three years ended December 31, 2012.

	Pension Benefits			Other Postretirement Benefits		
(Thousands of dollars)	**2012**	2011	2010	**2012**	2011	2010
Service cost	**$ 23,500**	22,406	20,706	**3,958**	4,547	4,133
Interest cost	**29,869**	30,785	30,144	**5,174**	6,141	6,211
Expected return on plan assets	**(25,826)**	(25,919)	(24,199)	**0**	0	0
Amortization of prior service cost (credit)	**1,254**	1,314	1,558	**(173)**	(240)	(263)
Amortization of transitional (asset) liability	**(529)**	(536)	(514)	**8**	8	8
Recognized actuarial loss	**16,389**	12,484	12,257	**1,317**	2,329	2,790
	44,657	40,534	39,952	**10,284**	12,785	12,879
Termination benefits expense	**6,177**	695	0	**0**	0	0
Curtailment expense	**0**	1,036	0	**0**	(605)	0
Net periodic benefit expense	**$ 50,834**	42,265	39,952	**10,284**	12,180	12,879

The increase in net periodic pension benefit expense in 2012 compared to 2011 was primarily related to expense recognized in the current year for enhanced retirement benefits provided to a former executive officer. The increase in net periodic pension benefit expense in 2011 compared to the prior year was mostly attributable to additional employees covered by retirement plans for both years, plus termination and curtailment expenses related to sale of two U.S. petroleum refineries in 2011. The reduction in the net periodic benefit expense for other postretirement plans in 2012 was due to no further service costs and lower other costs associated with postretirement benefits for the Meraux and Superior refineries sold in 2011.

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

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	**2012**	2011	**2012**	2011
Benefit obligation at December 31	**$184,550**	153,947	**525**	454
Fair value of plan assets at December 31	**164,111**	135,608	**0**	0
Net plan liabilities recognized	**20,439**	18,339	**525**	454
Net periodic benefit expense	**11,022**	8,978	**88**	82

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2012 and 2011 and net periodic benefit expense for 2012 and 2011.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	December 31		December 31		Year		Year	
	2012	2011	**2012**	2011	**2012**	2011	**2012**	2011
Discount rate	**4.24%**	5.00%	**4.18%**	4.87%	**4.80%**	5.50%	**4.87%**	5.50%
Expected return on plan assets	**6.20%**	6.48%	**0%**	0%	**6.20%**	6.48%	**0%**	0%
Rate of compensation increase	**4.13%**	4.22%	**0%**	0%	**4.10%**	4.22%	**0%**	0%

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

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

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
2013	$ 31,968	7,231
2014	32,978	7,512
2015	33,770	7,778
2016	34,461	8,074
2017	35,627	8,379
2018-2022	202,836	47,829

For purposes of measuring postretirement benefit obligations at December 31, 2012, the future annual rates of increase in the cost of health care were assumed to be 7.4% for 2013 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.

(Thousands of dollars)	1% Increase	1% Decrease
Effect on total service and interest cost components of net periodic postretirement benefit expense for the year ended December 31, 2012	$ 1,777	(1,383)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 2012	19,599	(15,724)

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) eliminated lifetime or annual coverage limits and required coverage for preventative health services beginning in September 2010; and (d) imposed a fee of $2 (subsequently adjusted for inflation) for each person covered by a health insurance policy beginning in September 2010. The Company provides a health care benefit plan to eligible U.S. employees and most U.S. retired employees. The new law did not significantly affect the Company's consolidated financial statements as of December 31, 2012, 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 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 65% with a range of 50% to 70% of total assets. Fixed income securities have a normal allocation of 30% with a range of 25% to 50%. Cash will normally have an allocation of 5% with a range of 0% to 20%. The Policy calls for diversification norms within the investment portfolios of both equity securities and fixed income securities.

The weighted average asset allocation for the Company's funded pension benefit plans at December 31, 2012 and 2011 are presented in the following table.

	December 31,	
	2012	2011
Equity securities	**62.9%**	62.3%
Fixed income securities	**36.1**	36.5
Cash equivalents	**1.0**	1.2
	100.0%	100.0%

The Company's weighted average expected return on plan assets was 6.20% in 2012 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 6.20% expected return was based on an expected average future equity securities return of 8.20% and a fixed income securities return of 3.70% and is net of average expected investment expenses of 0.39%. Over the last 10 years, the return on funded retirement plan assets has averaged 6.86%.

At December 31, 2012 and 2011, the fair value measurements of retirement plan assets within the fair value hierarchy are included in the table that follows.

		Fair Value Measurements Using		
(Thousands of dollars)	Fair Value at December 31, 2012	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Domestic Plans				
Equity securities:				
U.S. core equity	$ 83,392	83,392	0	0
U.S. small/midcap	20,894	20,894	0	0
U.S. long/short equity fund	14,654	0	14,654	0
International commingled trust fund	62,111	0	62,111	0
Emerging market commingled equity fund	9,535	0	9,535	0
Fixed income securities:				
U.S. fixed income	80,203	0	80,203	0
International commingled trust fund	15,179	0	15,179	0
Emerging market mutual fund	10,060	0	10,060	0
Cash and equivalents	3,407	3,407	0	0
Total Domestic Plans	299,435	107,693	191,742	0
Foreign Plans				
Equity securities funds	79,233	0	79,233	0
Fixed income securities funds	51,777	0	51,777	0
Diversified pooled fund	31,758	0	31,758	0
Cash and equivalents	1,343	1,343	0	0
Total Foreign Plans	164,111	1,343	162,768	0
Total	$463,546	109,036	354,510	0

(Thousands of dollars)	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)
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
Total Foreign Plans	135,608	1,827	133,781	0
Total	$404,350	97,252	307,098	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 2012, the Company made contributions of $27,456,000 to its domestic defined benefit pension plans, $14,751,000 to its foreign defined benefit pension plans, $4,614,000 to its domestic postretirement benefits plan and $46,000 to its foreign postretirement benefits plan. The Company currently expects during 2013 to make contributions of $26,659,000 to its domestic defined benefit pension plans, $16,192,000 to its foreign defined benefit pension plans, $5,607,000 to its domestic postretirement benefits plan and $40,000 to its foreign postretirement benefits plan.

THRIFT PLANS – Most full-time employees of the Company may participate in thrift or savings plans by allotting up to a specified percentage of their base pay. The Company matches contributions at a stated percentage of each employee's allotment based on years of participation in the plans, with a maximum match of 6%. A U.K. savings plan allows eligible employees to allot a portion of their base pay to purchase Company Common stock at market value. Such employee allotments are matched by the Company. Amounts charged to expense for these U.S. and U.K. plans were $12,594,000 in 2012, $10,725,000 in 2011 and $11,467,000 in 2010.

Note K – 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 risk related to corn that it will purchase in the future for feedstock and to wet and dried distillers grain with solubles that it will sell in the future at its ethanol production facilities in the United States. At December 31, 2012 and 2011, the Company had open physical delivery commitment contracts for purchase of approximately 19.2 million and 8.0 million bushels of corn, respectively, for processing at its ethanol plants. Also, at December 31, 2012 and 2011, the Company had open physical delivery commitment contracts for sale of approximately 1.0 million and 1.1 million equivalent bushels of wet and dried distillers grain with solubles, respectively. To manage the price risk associated with certain of these physical delivery commitments which have fixed prices, at December 31, 2012 and 2011, the Company had outstanding derivative contracts with a net volume of approximately 6.3 million and 6.7 million bushels, respectively, to mature at future prices in effect on the expected date of delivery under the 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 net asset of $2,941,000 at December 31, 2012 and a net liability of $292,000 at December 31, 2011.
- *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, 2012 and 2011, short-term derivative instruments were outstanding in Canada for approximately $154,000,000 and $16,000,000, respectively, to manage the currency risk associated with a U.S. dollar intercompany loan at year-end 2012 plus U.S. dollar accounts receivable balances associated with sale of Canadian crude oil in both years. Also short-term derivative instruments were outstanding at December 31, 2011 to manage the currency risk of approximately $472,000,000 equivalent of ringgit denominated income tax liability balances in the Company's Malaysian operations. The fair values of open foreign currency derivative contracts were liabilities of $1,031,000 at December 31, 2012 and $8,459,000 at December 31, 2011.

At December 31, 2012 and 2011, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

	December 31, 2012				December 31, 2011			
	Asset Derivatives		**Liability Derivatives**		Asset Derivatives		Liability Derivatives	
(Thousands of dollars)	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Type of Derivative Contract								
Commodity	**Accounts Receivable**	**$3,043**	**Accounts Payable**	**$102**	Accounts Receivable	$197	Accounts Payable	$489
Foreign exchange	—	—	**Accounts Payable**	**$1,031**	—	—	Accounts Payable	$8,459

For the years ended December 31, 2012 and 2011, the gains and losses recognized in the Consolidated Statements of Income for derivative instruments not designated as hedging instruments are presented in the following table.

	Year Ended December 31, 2012		Year Ended December 31, 2011	
(Thousands of dollars)	**Location of Gain (Loss) Recognized in Income on Derivative**	**Amount of Gain (Loss) Recognized in Income on Derivative**	Location of Gain (Loss) Recognized in Income on Derivative	Amount of Gain (Loss) Recognized in Income on Derivative
Type of Derivative Contract				
Commodity	**Crude Oil and Product Purchases**	**$(38,283)**	Crude Oil and Product Purchases	$5,659
Foreign exchange	**Interest and Other Income (Loss)**	**14,156**	Interest and Other Income (Loss)	(305)
		$(24,127)		$5,354

- *Interest Rate Risks* – The Company had ten-year notes totaling $350,000,000 that matured on May 1, 2012. The Company expected to replace these notes at maturity with new ten-year notes, and it therefore had 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 matured in May 2012. The Company utilized hedge accounting to defer any gain or loss on these contracts until the payment of interest on these anticipated notes occurs between 2012 and 2022. There was no impact in the 2011 Consolidated Statement of Income associated with accounting for these interest rate derivative contracts. During 2012, $1,852,000 of the deferred loss on the interest rate swaps was charged to income. The remaining loss deferred on these matured contracts at December 31, 2012 was $27,778,000, which is recorded, net of income taxes, in Accumulated Other Comprehensive Income in the Consolidated Balance Sheet. The Company expects to charge approximately $2,960,000 of this deferred loss to income in the form of interest expense during 2013.

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

(Thousands of dollars)	December 31, 2011 Liability Derivatives	
	Balance Sheet Location	Fair Value
Type of Derivative Contract		
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 L – Stockholders' Equity

On October 16, 2012, the Company announced a special dividend of $2.50 per outstanding Common share. The special dividend was paid on December 3, 2012, to shareholders of record on November 16, 2012, and totaled $486,141,000. The Company also announced authorization of a share buyback program of up to $1.0 billion. The share repurchases could be carried out by utilization of a number of different methods, including but not limited to, open market purchases, accelerated share repurchases and negotiated block purchases, and some of the repurchases may be effected through Rule 10b5-1 plans. On December 10, 2012, Murphy entered into a variable term, capped accelerated share repurchase (ASR) transaction with a major financial institution to repurchase an aggregate of $250,000,000 of the Company's Common stock. The total aggregate number of shares to be repurchased pursuant to this agreement will be determined by reference to the Rule 10b-18 volume-weighted price of the Company's Common stock, less a fixed discount, over the term of the agreement, subject to a minimum number of shares. The share repurchase agreement is expected to be completed no later than approximately five months after execution. Under the ASR program, Murphy received the minimum 3,867,550 shares of Common stock during the fourth quarter 2012. These shares were held in Treasury Stock at December 31, 2012. Any remaining shares will be delivered to the Company upon the completion of the ASR program. For accounting purposes, the ASR program is considered a treasury stock purchase and a forward contract indexed to Murphy's Common shares for the future settlement provision. The forward contracts are accounted for as equity instruments.

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, 2012. No difference existed between net income used in computing basic and diluted income per Common share for these years.

(Weighted-average shares outstanding)	**2012**	2011	2010
Basic method	**193,902,335**	193,409,621	191,830,357
Dilutive stock options	**766,402**	1,102,781	1,327,457
Diluted method	**194,668,737**	194,512,402	193,157,814

Outstanding options to purchase shares of Common stock were not included in the computation of diluted earnings per share in 2010 through 2012 when the incremental shares from assumed conversion were antidilutive. These included 3,329,689 shares at a weighted average share price of $64.72 in 2012, 1,823,564 shares at a weighted average share price of $69.46 in 2011 and 2,220,567 shares at a weighted average share price of $58.78 in 2010.

Note N – Other Financial Information

INVENTORIES – Inventories accounted for under the LIFO method totaled $262,160,000 and $188,390,000 at December 31, 2012 and 2011, respectively, and these amounts were $571,227,000 and $580,238,000 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, 2012 and 2011, the components of Accumulated Other Comprehensive Income are presented in the table that follows.

(Thousands of dollars)	**2012**	2011
Foreign currency translation gains, net of tax	**$ 613,492**	496,161
Retirement and postretirement plan adjustments, net of tax	**(186,539)**	(168,889)
Loss deferred on interest rate derivative contracts settled in 2012, net of tax	**(18,052)**	(16,852)
Balance at end of year	**$ 408,901**	310,420

At December 31, 2012, components of the net foreign currency translation gains of $613,492,000 were gains of $564,688,000 for Canadian dollars, $47,542,000 for pounds sterling and $1,262,000 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 $5,092,000 in 2012, $22,131,000 in 2011 and $(63,861,000) in 2010.

CASH FLOW DISCLOSURES – Cash income taxes paid were $566,999,000, $938,944,000 and $585,759,000 in 2012, 2011 and 2010, respectively. Interest paid, net of amounts capitalized, was $9,501,000, $38,120,000 and $35,452,000 in 2012, 2011 and 2010, respectively.

Noncash operating working capital (increased) decreased during each of the three years ended December 31, 2012 as shown in the following table.

(Thousands of dollars)	**2012**	2011	2010
Accounts receivable	**$(309,322)**	(43,630)	(4,363)
Inventories	**(157,657)**	(59,413)	(28,231)
Prepaid expenses	**(242,771)**	20,548	14,567
Deferred income tax assets	**(1,554)**	8,488	(80,073)
Accounts payable and accrued liabilities	**269,634**	(478,580)	766,113
Current income tax liabilities	**40,567**	(273,118)	(28,401)
Net (increase) decrease in noncash operating working capital	**$(401,103)**	(825,705)	639,612

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, 2012 and 2011 are presented in the following table.

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

(Thousands of dollars)	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

At the balance sheet dates 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 the Consolidated Statement of Income in Crude Oil and Product Purchases and the change in fair value of foreign currency exchange derivatives is recorded in Interest and Other Income (Loss). The interest rate derivative contracts are accounted for under hedge accounting rules; therefore, losses were deferred and 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 Expenses 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 an ethanol plant acquired in 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, 2012 and 2011. 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,			
	2012		2011	
(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	**$ 115,603**	**115,802**	532,093	532,899
Current and long-term debt	**(2,245,247)**	**(2,357,972)**	(599,558)	(715,208)

Note P – Commitments

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 Company operated retail fueling stations in the U.S. During the next five years, expected future rental payments under all operating leases are approximately $225,758,000 in 2013, $233,786,000 in 2014, $191,312,000 in 2015, $140,655,000 in 2016 and $123,401,000 in 2017. Rental expense for noncancellable operating leases, including contingent payments when applicable, was $178,292,000 in 2012, $185,016,000 in 2011 and $178,410,000 in 2010.

The Company has entered into contracts to hire various drilling rigs and associated equipment for periods beyond December 31, 2012. These rigs will primarily be utilized for drilling operations in the Gulf of Mexico, onshore U.S. and Canada and offshore Malaysia, Cameroon and Australia. Future commitments under these contracts, all of which expire by 2016, total $1,251,777,000. 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 oil and/or natural gas in the U.S. and Western Canada. These agreements require minimum monthly or annual payments for processing and/or transportation charges through 2023. Future required minimum monthly payments for the next five years are $36,394,000 in 2013, $35,224,000 in 2014, $30,226,000 in 2015, $19,427,000 in 2016 and $13,864,000 in 2017. 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 $19,733,000 in 2012, $24,791,000 in 2011 and $10,337,000 in 2010.

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 seven payments have been made through January 2013. The Company recorded a discounted liability of $38,700,000 in 2006 for this unconditional commitment. The liability was discounted at the Company's 10-year borrowing rate and the discounted liability increases for accretion monthly with a corresponding charge to Selling and General Expenses in the Consolidated Statement of Income. Total accretion cost was $1,063,000 in 2012, $1,317,000 in 2011 and $1,534,000 in 2010.

Commitments for capital expenditures were approximately $2,424,400,000 at December 31, 2012, including $977,800,000 for field development and future work commitments in Malaysia, $242,000,000 for costs to develop deepwater Gulf of Mexico fields, $474,100,000 for work in the Eagle Ford Shale, $146,800,000 for future work commitments offshore Brunei, $124,100,000 for future work commitments offshore Cameroon and $91,500,000 for future work commitments offshore Vietnam.

Note Q – 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 related to past operations of these refineries. The Company believes costs related to these sites will not have a material adverse affect on Murphy's net income, financial condition or liquidity in a future period.

The 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, 2012.

The U.S. Environmental Protection Agency (EPA) currently considers the Company to be a Potentially Responsible Party (PRP) at two Superfund sites. At one site, the Company has thus far been unable to ascertain any association with the Superfund site; Murphy intends to request further information as to the Company's connection to the site. The potential total cost to all parties to perform necessary remedial work at these sites 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 sites. Accordingly, the Company has not recorded a liability for remedial costs at the Superfund sites at December 31, 2012. 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 these sites or other Superfund sites. The Company believes that its share of the ultimate costs to remediate these Superfund sites will be immaterial and will not have a material adverse effect on its net income, financial condition or liquidity in a future period.

In 2011, Murphy was notified by the U.K. Environment Agency (EA) that it failed to surrender sufficient greenhouse gas emission allowances, which Murphy self-reported to the EA in 2010. The EA has issued a civil penalty notice of approximately $1,700,000. The Company is pursuing all available options regarding this matter.

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, 2012, the Company had contingent liabilities of $7,798,000 under a financial guarantee and $298,971,000 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.

Note R – 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 recorded expense of $18,582,000 in 2010 based on the anticipated working interest reduction. The Company made a cash settlement payment to certain Terra Nova partners in January 2011 to equalize all partners' interest in the field since about February 2005 related to the Company's working interest reduction. Based on the final settlement paid in 2011, the Company recorded a pretax benefit of $5,351,000 in 2011 due to the ultimate cost of the redetermination settlement being less than originally estimated. The 2010 expense and the 2011 benefit have been reflected as Redetermination of Terra Nova Working Interest in the Consolidated Statements of Income.

Note S – Common Stock Issued and Outstanding

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2012 is shown below.

(Number of shares outstanding)	**2012**	2011	2010
At beginning of year	**193,723,208**	192,836,008	191,115,378
Stock options exercised*	**482,974**	615,674	1,495,926
Employee stock purchase and thrift plans	**78,389**	33,390	49,657
Restricted stock awards, net of forfeitures	**224,296**	238,136	175,047
Treasury shares purchased	**(3,867,550)**	0	0
At end of year	**190,641,317**	193,723,208	192,836,008

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

Note T – 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, 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 Company sells gasoline in the United States at retail stations built primarily at Walmart Supercenters. The United States business also derives revenue from production and sale of ethanol and distillers grain with solubles. 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.

In 2012, the Company's Board of Directors agreed to sell the U.K. exploration and production operations. The assets and liabilities associated with these U.K. oil and gas operations at December 31, 2012 are reported as held for sale in the Consolidated Balance Sheet and the results of operations are reported as discontinued operations for all periods presented in the Consolidated Statements of Income and in the segment table that follows. The sale of these U.K. oil and gas assets is expected to be completed in early 2013. In 2010, the Company announced its intention to sell its two U.S. refineries and its U.K. refining and marketing operations. On September 30, 2011, the Company completed the sale of the Superior, Wisconsin refinery and associated marketing assets. On October 1, 2011, the Company completed the sale of the Meraux, Louisiana refinery and associated marketing assets. The results of operations for the Superior and Meraux refineries and associated marketing assets have been reported as discontinued operations for all periods presented. The Company continues to actively market for sale the U.K. downstream assets. In 2012, the Company announced that its Board of Directors had approved a plan to separate the Company's U.S. downstream subsidiary in the form of an independent, publicly owned company. The Company currently expects to complete this separation in 2013. If under U.S. generally accepted accounting principles the U.K. and U.S. downstream operations cease to qualify as continuing operations in future periods, the results of these operations would be presented as discontinued operations in the Company's consolidated financial statements.

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 $2,721,270,000, $2,796,122,000 and $2,784,368,000 for the years 2012, 2011 and 2010, respectively, which were collected by the Company's continuing operations and remitted to various government entities, were excluded from revenues and costs and expenses.

Segment Information

(Millions of dollars)	Exploration and Production					
	United States	Canada	Malaysia	Republic of the Congo	Other	Total
Year ended December 31, 2012						
Segment income (loss)	**$ 168.0**	**208.1**	**894.2**	**(241.1)**	**(124.2)**	**905.0**
Revenues from external customers	**1,038.0**	**1,084.3**	**2,428.1**	**57.6**	**0.1**	**4,608.1**
Intersegment revenues	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Interest income	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Interest expense, net of capitalization	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Income tax expense (benefit)	**99.8**	**65.1**	**544.7**	**(64.5)**	**(40.1)**	**605.0**
Significant noncash charges (credits)						
Depreciation, depletion, amortization	**330.2**	**345.8**	**532.1**	**33.9**	**2.4**	**1,244.4**
Accretion of asset retirement obligations	**11.4**	**13.6**	**12.5**	**0.9**	**0.0**	**38.4**
Amortization of undeveloped leases	**71.6**	**29.3**	**0.0**	**0.0**	**28.9**	**129.8**
Impairment of long-lived assets	**0.0**	**0.0**	**0.0**	**200.0**	**0.0**	**200.0**
Deferred and noncurrent income taxes	**231.0**	**72.3**	**73.3**	**(0.3)**	**(1.2)**	**375.1**
Additions to property, plant, equipment	**1,615.9**	**887.2**	**1,426.7**	**(20.7)**	**24.7**	**3,933.8**
Total assets at year-end	**3,625.9**	**4,477.7**	**4,811.5**	**112.2**	**75.6**	**13,102.9**
Year ended December 31, 2011						
Segment income (loss)	$ 152.7	328.0	812.7	(385.3)	(293.9)	614.2
Revenues from external customers	737.7	1,145.8	2,045.6	148.8	24.6	4,102.5
Intersegment revenues	0.0	142.8	0.0	0.0	0.0	142.8
Interest income	0.0	0.0	0.0	0.0	0.0	0.0
Interest expense, net of capitalization	0.0	0.0	0.0	0.0	0.0	0.0
Income tax expense (benefit)	86.5	135.5	434.9	16.4	7.5	680.8
Significant noncash charges (credits)						
Depreciation, depletion, amortization	183.0	326.0	357.3	87.8	1.9	956.0
Accretion of asset retirement obligations	9.9	12.5	10.6	0.5	0.3	33.8
Amortization of undeveloped leases	62.2	28.8	0.0	0.0	27.2	118.2
Impairment of long-lived assets	0.0	0.0	0.0	368.6	0.0	368.6
Deferred and noncurrent income taxes	54.2	39.6	84.6	(0.9)	(0.1)	177.4
Additions to property, plant, equipment	696.6	885.2	694.8	79.6	20.6	2,376.8
Total assets at year-end	2,227.6	3,746.8	3,826.9	257.5	74.1	10,132.9
Year ended December 31, 2010						
Segment income (loss)	$ 72.7	213.8	659.4	(77.2)	(92.3)	776.4
Revenues from external customers	659.9	780.2	1,837.9	155.7	3.9	3,437.6
Intersegment revenues	0.0	118.9	0.0	0.0	0.0	118.9
Interest income	0.0	0.0	0.0	0.0	0.0	0.0
Interest expense, net of capitalization	0.0	0.0	0.0	0.0	0.0	0.0
Income tax expense (benefit)	30.0	79.1	414.1	20.6	0.5	544.3
Significant noncash charges (credits)						
Depreciation, depletion, amortization	281.1	225.5	379.0	95.5	1.5	982.6
Accretion of asset retirement obligations	6.9	11.2	9.8	0.4	0.5	28.8
Amortization of undeveloped leases	68.5	33.7	0.0	0.0	5.8	108.0
Deferred and noncurrent income taxes	(48.6)	34.5	145.5	(0.9)	0.0	130.5
Additions to property, plant, equipment	369.4	804.4	467.9	163.6	49.8	1,855.1
Total assets at year-end	1,651.3	3,242.6	3,333.1	678.9	88.9	8,994.8

Geographic Information

(Millions of dollars)	Certain Long-Lived Assets at December 31						
	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Other	Total
2012	**$4,177.4**	**4,190.5**	**4,101.2**	**703.2**	**5.9**	**39.2**	**13,217.4**
2011	2,953.1	3,493.4	3,154.8	694.7	133.7	52.2	10,481.9
2010	3,178.8	3,028.8	2,807.0	706.3	579.4	74.3	10,374.6

Segment Information (Continued)

(Millions of dollars)	Refining and Marketing United States	Refining and Marketing United Kingdom	Refining and Marketing Total	Corporate and Other	Discontinued Operations	Consolidated
Year ended December 31, 2012						
Segment income (loss)	**$ 105.4**	**52.2**	**157.6**	**(98.5)**	**6.8**	**970.9**
Revenues from external customers	**17,723.4**	**6,283.0**	**24,006.4**	**11.5**	**0.0**	**28,626.0**
Intersegment revenues	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Interest income	**0.0**	**0.0**	**0.0**	**6.5**	**0.0**	**6.5**
Interest expense, net of capitalization	**0.0**	**0.0**	**0.0**	**14.9**	**0.0**	**14.9**
Income tax expense (benefit)	**72.7**	**24.7**	**97.4**	**(43.5)**	**0.0**	**658.9**
Significant noncash charges (credits)						
Depreciation, depletion, amortization	**75.2**	**47.3**	**122.5**	**8.7**	**0.0**	**1,375.6**
Accretion of asset retirement obligations	**0.9**	**0.0**	**0.9**	**0.0**	**0.0**	**39.3**
Amortization of undeveloped leases	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**129.8**
Impairment of long-lived assets	**61.0**	**0.0**	**61.0**	**0.0**	**0.0**	**261.0**
Deferred and noncurrent income taxes	**(20.0)**	**(6.2)**	**(26.2)**	**(32.3)**	**0.0**	**316.6**
Additions to property, plant, equipment	**111.5**	**22.2**	**133.7**	**8.2**	**58.1**	**4,133.8**
Total assets at year-end	**2,026.5**	**1,160.3**	**3,186.8**	**1,009.6**	**223.3**	**17,522.6**
Year ended December 31, 2011						
Segment income (loss)	$ 223.6	(33.3)	190.3	(75.0)	143.2	872.7
Revenues from external customers	17,471.9	6,030.3	23,502.2	33.4	0.0	27,638.1
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	(52.1)	0.0	763.2
Significant noncash charges (credits)						
Depreciation, depletion, amortization	68.3	46.7	115.0	8.7	0.0	1,079.7
Accretion of asset retirement obligations	0.9	0.0	0.9	0.0	0.0	34.7
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	157.0
Additions to property, plant, equipment	100.1	22.2	122.3	5.3	67.8	2,572.2
Total assets at year-end	1,806.5	1,193.8	3,000.3	790.8	214.1	14,138.1
Year ended December 31, 2010						
Segment income (loss)	$ 165.3	(34.7)	130.6	(157.9)	49.0	798.1
Revenues from external customers	13,750.4	2,905.0	16,655.4	(56.9)	0.0	20,036.1
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	576.6
Significant noncash charges (credits)						
Depreciation, depletion, amortization	60.1	41.4	101.5	8.0	0.0	1,092.1
Accretion of asset retirement obligations	0.8	0.0	0.8	0.0	0.0	29.6
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	146.6
Additions to property, plant, equipment	221.0	69.1	290.1	5.9	112.6	2,263.7
Total assets at year-end	2,996.6	1,113.6	4,110.2	940.3	187.9	14,233.2

Geographic Information

(Millions of dollars)	Revenues from External Customers for the Year: United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Other	Total
2012	**$18,729.9**	**1,119.9**	**2,415.6**	**6,302.7**	**57.6**	**0.3**	**28,626.0**
2011	18,184.0	1,180.3	2,063.0	6,037.4	148.8	24.6	27,638.1
2010	14,386.6	809.3	1,793.8	2,885.1	156.5	4.8	20,036.1

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

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

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

Murphy has utilized reliable geologic and engineering technology in 2011 and 2012 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 reasonably certain results.

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

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

Oil and natural gas reserves in Malaysia are associated with production sharing contracts for Blocks SK 309/311 and K. Malaysia reserves include oil and gas to be received for both cost recovery and profit provisions under the contracts. Oil and natural gas proved reserves associated with the production sharing contracts in Malaysia totaled 95.7 million barrels and 357.6 billion cubic feet, respectively, at December 31, 2012. Approximately 72.8 billion cubic feet of natural gas proved reserves in Malaysia relate to fields in Block K for which the Company expects to receive sale proceeds of approximately $0.24 per thousand cubic feet.

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

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

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

Schedule 5 also presents the principal reasons for change in the standardized measure of discounted future net cash flows for each of the three years ended December 31, 2012.

Schedule 1 – Summary of Proved Oil Reserves Based on Average Prices for 2009 – 2012

	Total	Total – by product		United States	Canada		Malaysia	United Kingdom	Republic of the Congo
(Millions of barrels)	All Products	Oil	Synthetic Oil	Oil	Oil	Synthetic Oil	Oil	Oil	Oil
Proved developed and undeveloped oil reserves:									
December 31, 2009	313.4	183.9	129.5	26.4	27.8	129.5	110.1	11.7	7.9
Revisions of previous estimates	22.5	18.0	4.5	3.5	5.4	4.5	4.4	0.4	4.3
Improved recovery	5.8	5.8	0.0	0.0	1.0	0.0	4.8	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
Production	(46.3)	(41.5)	(4.8)	(7.4)	(6.4)	(4.8)	(24.4)	(1.2)	(2.1)
December 31, 2010	308.0	178.8	129.2	26.6	32.8	129.2	98.4	10.9	10.1
Revisions of previous estimates	21.2	16.0	5.2	2.4	3.1	5.2	8.4	8.1	(6.0)
Improved recovery	14.2	14.2	0.0	0.0	0.0	0.0	10.7	3.5	0.0
Extensions and discoveries	43.9	43.9	0.0	32.6	6.7	0.0	4.6	0.0	0.0
Production	(37.6)	(32.7)	(4.9)	(6.3)	(6.0)	(4.9)	(17.7)	(0.9)	(1.8)
December 31, 2011	349.7	220.2	129.5	55.3	36.6	129.5	104.4	21.6	2.3
Revisions of previous estimates	**2.6**	**7.9**	**(5.3)**	**13.0**	**(3.4)**	**(5.3)**	**(0.4)**	**0.3**	**(1.6)**
Improved recovery	**7.2**	**7.2**	**0.0**	**0.0**	**0.0**	**0.0**	**7.2**	**0.0**	**0.0**
Extensions and discoveries	**84.0**	**84.0**	**0.0**	**77.3**	**2.9**	**0.0**	**3.8**	**0.0**	**0.0**
Purchases of properties	**12.5**	**12.5**	**0.0**	**6.5**	**6.0**	**0.0**	**0.0**	**0.0**	**0.0**
Production	**(41.2)**	**(36.1)**	**(5.1)**	**(9.5)**	**(5.3)**	**(5.1)**	**(19.3)**	**(1.3)**	**(0.7)**
December 31, 2012	**414.8**	**295.7**	**119.1**	**142.6**	**36.8**	**119.1**	**95.7**	**20.6**	**0.0**
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
December 31, 2010	248.3	129.2	119.1	15.8	28.6	119.1	66.5	10.9	7.4
December 31, 2011	238.5	118.0	120.5	20.8	32.6	120.5	57.2	5.1	2.3
December 31, 2012	**267.7**	**148.6**	**119.1**	**48.0**	**29.5**	**119.1**	**67.0**	**4.1**	**0.0**
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
December 31, 2010	59.7	49.6	10.1	10.8	4.2	10.1	31.9	0.0	2.7
December 31, 2011	111.2	102.2	9.0	34.5	4.0	9.0	47.2	16.5	0.0
December 31, 2012	**147.1**	**147.1**	**0.0**	**94.6**	**7.3**	**0.0**	**28.7**	**16.5**	**0.0**

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.

2012 Comments for Proved Oil Reserves Changes

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

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

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

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

Schedule 2 – Summary of Proved Natural Gas Reserves Based on Average Prices for 2009 – 2012

(Billions of cubic feet)	Total	United States	Canada	Malaysia	United Kingdom
Proved developed and undeveloped natural gas reserves:					
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
Revisions of previous estimates	**20.2**	**16.5**	**(37.2)**	**41.4**	**(0.5)**
Improved recovery	**7.2**	**0.0**	**0.0**	**7.2**	**0.0**
Extensions and discoveries	**173.5**	**107.2**	**25.8**	**40.5**	**0.0**
Purchases of properties	**9.4**	**7.0**	**2.4**	**0.0**	**0.0**
Production	**(179.4)**	**(19.4)**	**(79.5)**	**(79.3)**	**(1.2)**
December 31, 2012	**1,137.0**	**209.7**	**550.4**	**357.6**	**19.3**
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
December 31, 2012	**706.0**	**78.8**	**415.8**	**197.3**	**14.1**
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
December 31, 2012	**431.0**	**130.9**	**134.6**	**160.3**	**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.

2012 Comments for Proved Natural Gas Reserves Changes

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

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

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

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

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

(Millions of dollars)	United States	Canada	Malaysia	United Kingdom[1]	Republic of the Congo	Other	Total
Year Ended December 31, 2012							
Property acquisition costs							
Unproved	**$ 107.7**	**14.6**	**0.0**	**0.0**	**0.0**	**10.2**	**132.5**
Proved	**69.1**	**242.4**	**0.0**	**0.0**	**0.0**	**0.0**	**311.5**
Total acquisition costs	**176.8**	**257.0**	**0.0**	**0.0**	**0.0**	**10.2**	**444.0**
Exploration costs[2]	**174.5**	**57.0**	**68.8**	**(1.0)**	**51.1**	**97.6**	**448.0**
Development costs[2]	**1,352.7**	**664.5**	**1,433.7**	**46.6**	**22.6**	**1.6**	**3,521.7**
Total costs incurred	**1,704.0**	**978.5**	**1,502.5**	**45.6**	**73.7**	**109.4**	**4,413.7**
Charged to expense							
Dry hole expense	**32.3**	**8.0**	**26.1**	**(0.8)**	**76.2**	**39.3**	**181.1**
Geophysical and other costs	**19.6**	**2.5**	**1.1**	**(0.2)**	**0.6**	**45.4**	**69.0**
Total charged to expense	**51.9**	**10.5**	**27.2**	**(1.0)**	**76.8**	**84.7**	**250.1**
Property additions	**$1,652.1**	**968.0**	**1,475.3**	**46.6**	**(3.1)**	**24.7**	**4,163.6**
Year Ended December 31, 2011							
Property acquisition costs							
Unproved	$ 233.8	18.5	0.0	0.0	0.0	27.0	279.3
Proved	0.0	0.0	0.0	0.0	23.5	0.0	23.5
Total acquisition costs	233.8	18.5	0.0	0.0	23.5	27.0	302.8
Exploration costs[2]	253.2	76.0	0.7	0.5	0.5	231.6	562.5
Development costs[2]	263.9	871.9	705.5	30.5	78.7	3.8	1,954.3
Total costs incurred	750.9	966.4	706.2	31.0	102.7	262.4	2,819.6
Charged to expense							
Dry hole expense	0.6	50.6	0.1	0.0	18.1	181.6	251.0
Geophysical and other costs	35.9	10.2	11.0	0.5	2.9	60.2	120.7
Total charged to expense	36.5	60.8	11.1	0.5	21.0	241.8	371.7
Property additions	$ 714.4	905.6	695.1	30.5	81.7	20.6	2,447.9
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[2]	204.1	1.8	99.6	6.7	93.5	67.7	473.4
Development costs[2]	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

1 The Company has accounted for U.K. operations as discontinued operations due to the impending sale of these operations in early 2013.

2 Includes non-cash asset retirement costs as follows:

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

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

(Millions of dollars)	United States	Canada Conven-tional	Canada Synthetic	Malaysia	Republic of the Congo	Other	Total
Year Ended December 31, 2012							
Revenues							
Crude oil and natural gas liquids							
Sales to unaffiliated enterprises	**$ 976.1**	**411.7**	**463.1**	**1,946.0**	**57.6**	**0.0**	**3,854.5**
Natural gas							
Sales to unaffiliated enterprises	**54.2**	**209.8**	**0.0**	**481.1**	**0.0**	**0.0**	**745.1**
Total oil and gas revenues	**1,030.3**	**621.5**	**463.1**	**2,427.1**	**57.6**	**0.0**	**4,599.6**
Other operating revenues	**7.7**	**(0.9)**	**0.6**	**1.0**	**0.0**	**0.1**	**8.5**
Total revenues	**1,038.0**	**620.6**	**463.7**	**2,428.1**	**57.6**	**0.1**	**4,608.1**
Costs and expenses							
Production expenses	**252.4**	**167.2**	**224.1**	**422.7**	**48.4**	**0.0**	**1,114.8**
Exploration costs charged to expense	**51.9**	**10.5**	**0.0**	**27.2**	**76.8**	**84.7**	**251.1**
Undeveloped lease amortization	**71.6**	**29.3**	**0.0**	**0.0**	**0.0**	**28.9**	**129.8**
Depreciation, depletion and amortization	**330.2**	**290.5**	**55.3**	**532.1**	**33.9**	**2.4**	**1,244.4**
Accretion of asset retirement obligations	**11.4**	**5.1**	**8.5**	**12.5**	**0.9**	**0.0**	**38.4**
Impairment of properties	**0.0**	**0.0**	**0.0**	**0.0**	**200.0**	**0.0**	**200.0**
Selling and general expenses	**52.7**	**19.7**	**0.9**	**(5.3)**	**3.2**	**48.4**	**119.6**
Total costs and expenses	**770.2**	**522.3**	**288.8**	**989.2**	**363.2**	**164.4**	**3,098.1**
	267.8	**98.3**	**174.9**	**1,438.9**	**(305.6)**	**(164.3)**	**1,510.0**
Income tax expense (benefit)	**99.8**	**25.1**	**40.0**	**544.7**	**(64.5)**	**(40.1)**	**605.0**
Results of operations	**$ 168.0**	**73.2**	**134.9**	**894.2**	**(241.1)**	**(124.2)**	**905.0**
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	148.8	0.0	3,250.0
Transfers to consolidated operations	0.0	46.4	96.4	0.0	0.0	0.0	142.8
Natural gas							
Sales to unaffiliated enterprises	71.1	280.2	0.0	461.3	0.0	0.0	812.6
Total oil and gas revenues	719.9	785.8	506.6	2,044.3	148.8	0.0	4,205.4
Other operating revenues	17.8	(3.8)	0.0	1.3	0.0	24.6	39.9
Total revenues	737.7	782.0	506.6	2,045.6	148.8	24.6	4,245.3
Costs and expenses							
Production expenses	164.8	151.2	236.1	420.6	37.6	0.0	1,010.3
Exploration costs charged to expense	36.5	60.8	0.0	11.1	21.0	241.8	371.2
Undeveloped lease amortization	62.2	28.8	0.0	0.0	0.0	27.2	118.2
Depreciation, depletion and amortization	183.0	273.9	52.1	357.3	87.8	1.9	956.0
Accretion of asset retirement obligations	9.9	4.9	7.6	10.6	0.5	0.3	33.8
Impairment of properties	0.0	0.0	0.0	0.0	368.6	0.0	368.6
Terra Nova working interest redetermination	0.0	(5.4)	0.0	0.0	0.0	0.0	(5.4)
Selling and general expenses	42.1	14.2	0.9	(1.6)	2.2	39.8	97.6
Total costs and expenses	498.5	528.4	296.7	798.0	517.7	311.0	2,950.3
	239.2	253.6	209.9	1,247.6	(368.9)	(286.4)	1,295.0
Income tax expense	86.5	79.7	55.8	434.9	16.4	7.5	680.8
Results of operations	$ 152.7	173.9	154.1	812.7	(385.3)	(293.9)	614.2

* Results exclude corporate overhead, interest and discontinued operations.

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

(Millions of dollars)	United States	Canada Conven-tional	Canada Synthetic	Malaysia	Republic of the Congo	Other	Total
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	156.7	0.0	2,893.7
Transfers to consolidated operations	0.0	42.2	76.7	0.0	0.0	0.0	118.9
Natural gas							
Sales to unaffiliated enterprises	87.0	132.1	0.0	307.1	0.0	0.0	526.2
Total oil and gas revenues	644.6	520.7	378.6	1,838.2	156.7	0.0	3,538.8
Other operating revenues	15.3	(0.2)	0.0	(0.3)	(1.0)	3.9	17.7
Total revenues	659.9	520.5	378.6	1,837.9	155.7	3.9	3,556.5
Costs and expenses							
Production expenses	131.7	97.5	206.4	355.0	62.0	0.0	852.6
Exploration costs charged to expense	35.7	1.9	0.0	19.8	56.4	54.3	168.1
Undeveloped lease amortization	68.5	33.7	0.0	0.0	0.0	5.8	108.0
Depreciation, depletion and amortization	281.1	180.3	45.2	379.0	95.5	1.5	982.6
Accretion of asset retirement obligations	6.9	4.8	6.4	9.8	0.4	0.5	28.8
Terra Nova working interest redetermination	0.0	18.6	0.0	0.0	0.0	0.0	18.6
Selling and general expenses	33.3	10.5	0.9	0.8	(2.0)	33.6	77.1
Total costs and expenses	557.2	347.3	258.9	764.4	212.3	95.7	2,235.8
	102.7	173.2	119.7	1,073.5	(56.6)	(91.8)	1,320.7
Income tax expense	30.0	44.6	34.5	414.1	20.6	0.5	544.3
Results of operations	$ 72.7	128.6	85.2	659.4	(77.2)	(92.3)	776.4

* Results exclude corporate overhead, interest and discontinued operations.

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

(Millions of dollars)	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Total
December 31, 2012						
Future cash inflows	**$ 15,547.5**	**15,511.6**	**10,354.9**	**2,395.2**	**0.0**	**43,809.2**
Future development costs	**(3,731.6)**	**(1,815.2)**	**(966.9)**	**(273.2)**	**0.0**	**(6,786.9)**
Future production and abandonment costs	**(3,466.6)**	**(7,336.4)**	**(3,143.4)**	**(738.3)**	**0.0**	**(14,684.7)**
Future income taxes	**(2,527.6)**	**(1,714.9)**	**(1,675.9)**	**(872.7)**	**0.0**	**(6,791.1)**
Future net cash flows	**5,821.7**	**4,645.1**	**4,568.7**	**511.0**	**0.0**	**15,546.5**
10% annual discount for estimated timing of cash flows	**(2,862.1)**	**(2,876.5)**	**(1,322.9)**	**(372.2)**	**0.0**	**(7,433.7)**
Standardized measure of discounted future net cash flows	**$ 2,959.6**	**1,768.6**	**3,245.8**	**138.8**	**0.0**	**8,112.8**
December 31, 2011						
Future cash inflows	$ 6,105.4	18,835.5	11,037.5*	2,509.5	248.6	38,736.5*
Future development costs	(1,283.5)	(1,929.5)	(1,559.8)	(356.2)	(0.0)	(5,129.0)
Future production and abandonment costs	(1,417.9)	(7,199.7)	(3,087.8)*	(763.0)	(183.8)	(12,652.2)*
Future income taxes	(807.2)	(2,806.8)	(2,129.7)	(869.0)	(39.7)	(6,652.4)
Future net cash flows	2,596.8	6,899.5	4,260.2	521.3	25.1	14,302.9
10% annual discount for estimated timing of cash flows	(912.0)	(3,658.7)	(1,507.4)	(304.4)	2.8	(6,379.7)
Standardized measure of discounted future net cash flows	$ 1,684.8	3,240.8	2,752.8	216.9	27.9	7,923.2
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

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

(Millions of dollars)	**2012**	2011	2010
Net changes in prices, production costs and development costs	**$(6,321.2)**	(370.5)	240.1
Sales and transfers of oil and gas produced, net of production costs	**(3,493.3)**	(3,273.5)	(2,792.2)
Net change due to extensions and discoveries	**4,466.3**	3,300.9	1,022.2
Net change due to purchases and sales of proved reserves	**347.4**	0.0	48.7
Development costs incurred	**3,299.0**	1,881.5	1,271.3
Accretion of discount	**1,153.5**	827.7	698.9
Revisions of previous quantity estimates	**728.1**	892.5	798.8
Net change in income taxes	**9.8**	(1,029.4)	(450.2)
Net increase	**189.6**	2,229.2	837.6
Standardized measure at January 1	**7,923.2**	5,694.0	4,856.4
Standardized measure at December 31	**$8,112.8**	7,923.2	5,694.0

* Reclassified to conform to current presentation.

Schedule 6 – Capitalized Costs Relating to Oil and Gas Producing Activities

(Millions of dollars)	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Other	Subtotal	Synthetic Oil – Canada	Total
December 31, 2012									
Unproved oil and gas properties	**$ 750.0**	**510.9**	**837.0**	**0.0**	**11.8**	**107.4**	**2,217.1**	**0.0**	**2,217.1**
Proved oil and gas properties	**3,972.1**	**4,697.8**	**5,260.7**	**603.2**	**737.8**	**0.0**	**15,271.6**	**1,435.6**	**16,707.2**
Gross capitalized costs	**4,722.1**	**5,208.7**	**6,097.7**	**603.2**	**749.6**	**107.4**	**17,488.7**	**1,435.6**	**18,924.3**
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	**(183.8)**	**(244.3)**	**(0.0)**	**(0.0)**	**(6.1)**	**(70.0)**	**(504.2)**	**(0.0)**	**(504.2)**
Proved oil and gas properties	**(1,590.6)**	**(1,828.8)**	**(2,001.8)**	**(397.5)**	**(737.8)**	**(0.0)**	**(6,556.5)**	**(389.6)**	**(6,946.1)**
Net capitalized costs	**$ 2,947.7**	**3,135.6**	**4,095.9**	**205.7**	**5.7**	**37.4**	**10,428.0**	**1,046.0**	**11,474.0**
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

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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL QUARTERLY INFORMATION (UNAUDITED)

(Millions of dollars except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Year Ended December 31, 2012					
Sales and other operating revenues	**$6,953.9**	**7,146.8**	**7,130.6**	**7,385.0**	**28,616.3**
Income from continuing operations before income taxes	**465.6**	**488.0**	**406.7**	**262.7**	**1,623.0**
Income from continuing operations	**281.5**	**291.3**	**228.9**	**162.4**	**964.1**
Net income	**290.1**	**295.4**	**226.7**	**158.7**	**970.9**
Income from continuing operations per Common share					
Basic	**1.45**	**1.50**	**1.18**	**0.84**	**4.97**
Diluted	**1.44**	**1.50**	**1.17**	**0.84**	**4.95**
Net income per Common share					
Basic	**1.50**	**1.52**	**1.17**	**0.82**	**5.01**
Diluted	**1.49**	**1.52**	**1.16**	**0.82**	**4.99**
Cash dividend per Common share	**0.275**	**0.275**	**0.3125**	**2.8125**[1]	**3.675**[1]
Market price of Common Stock[2]					
High	**64.76**	**57.12**	**56.24**	**63.74**	**64.76**
Low	**55.82**	**43.65**	**48.80**	**54.97**	**43.65**
Year Ended December 31, 2011					
Sales and other operating revenues	$6,236.0	7,351.1	7,194.4	6,800.9	27,582.4
Income from continuing operations before income taxes	393.2	486.2	526.7	86.5	1,492.6
Income (loss) from continuing operations	229.5	270.6	347.3	(117.9)	729.5
Net income (loss)	268.9	311.6	406.1	(113.9)	872.7
Income (loss) from continuing operations per Common share					
Basic	1.19	1.40	1.80	(0.61)	3.77
Diluted	1.18	1.39	1.79	(0.61)	3.75
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[2]					
High	76.11	77.48	69.71	58.67	77.48
Low	65.74	62.53	44.05	42.10	42.10

[1] Includes special dividend of $2.50 per Common share paid on December 3, 2012.
[2] Prices are as quoted on the New York Stock Exchange.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SCHEDULE II – VALUATION ACCOUNTS AND RESERVES

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

* Amounts primarily represent changes in foreign currency exchange rates.

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

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Corporate Information

Corporate Office
200 Peach Street
P.O. Box 7000
El Dorado, Arkansas 71731-7000
(870) 862-6411

Stock Exchange Listings
Trading Symbol: MUR
New York Stock Exchange

Transfer Agent and Registrar
Computershare Trust Company, N.A.
Toll-free (888) 239-5303
Local Chicago (312) 360-5303

(Address for overnight delivery)
250 Royall Street
Mail Stop 1A
Canton, MA 02021

(Address for first class mail,
registered mail and certified mail)
P.O. Box 43036
Providence, RI 02940

Electronic Payment of Dividends
Shareholders may have dividends deposited directly into their bank accounts by electronic funds transfer. Authorization forms may be obtained by contacting Computershare as described under Transfer Agent and Registrar above.

E-mail Address
murphyoil@murphyoilcorp.com

Web Site
www.murphyoilcorp.com
Murphy Oil's website provides frequently updated information about the Company and its operations, including:

- News releases
- Annual report
- Quarterly reports
- Live webcasts of quarterly conference calls
- Links to the Company's SEC filings
- Stock quotes
- Profiles of the Company's operations
- Murphy USA station locator

Annual Meeting
The annual meeting of the Company's stockholders will be held at 10:00 a.m. on May 8, 2013, at the South Arkansas Arts Center, 110 East 5th Street, El Dorado, Arkansas. A formal notice of the meeting, together with a proxy statement and proxy form, will be provided to all shareholders.

Inquiries
Inquiries regarding shareholder account matters should be addressed to:

John A. Moore
Manager, Law and Corporate Secretary
Murphy Oil Corporation
P.O. Box 7000
El Dorado, Arkansas 71731-7000
jmoore@murphyoilcorp.com

Members of the financial community should direct their inquiries to:

Barry Jeffery
Director, Investor Relations
Murphy Oil Corporation
P.O. Box 7000
El Dorado, Arkansas 71731-7000
(870) 864-6501
bjeffery@murphyoilcorp.com

Executive Officers

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

Roger W. Jenkins
Chief Operating Officer since June 2012. Mr. Jenkins became Executive Vice President in August 2009, and has served as President of Murphy Exploration & Production Company since January 2009. Prior to that he was Senior Vice President, North America for this subsidiary from September 2007 to December 2008.

Kevin G. Fitzgerald
Executive Vice President and Chief Financial Officer since December 2011. Mr. Fitzgerald was Senior Vice President and Chief Financial Officer from January 2007 to November 2011, and was Treasurer from July 2001 through December 2006.

Thomas McKinlay
Executive Vice President, U.K. Downstream since January 2013. Mr. McKinlay was Executive Vice President, Worldwide Downstream from January 2011 to January 2013 and was Vice President, U.S. Manufacturing from August 2009 to January 2011. Additionally, Mr. McKinlay was President of Murphy Oil USA, Inc. from January 2011 to January 2013. He was Senior Vice President of this U.S. subsidiary from April 2009 to January 2011, and from August 2008 to March 2009, was General Manager, Supply and Transportation.

Bill H. Stobaugh
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
Senior Vice President and General Counsel since March 2011. Mr. Compton was Vice President, Law from February 2009 to February 2011, and Manager, Law from November 1996 to January 2009.

John W. Eckart
Senior Vice President and Controller since December 2011. Mr. Eckart was Vice President and Controller from January 2007 to November 2011, and has been Controller since March 2000.

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

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

Thomas J. Mireles
Vice President, Corporate Planning & Development since February 2012. Mr. Mireles was General Manager, Planning & Analysis from June 2010 to January 2012. He also 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
Secretary since March 2011. Mr. Moore was Senior Attorney from August 2005 to February 2011.

MURPHY
OIL CORPORATION

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