Murphy Oil Corporation

2010 Annual Report

Financial and Operating Highlights

(Thousands of dollars except per share data)	2010	2009	% Change 2010–2009	2008	% Change 2009–2008
For the Year					
Revenues	**$23,345,071**	$19,012,392	**23%**	$27,432,331	-31%
Income from continuing operations	**798,081**	740,517	**8%**	1,744,749	-58%
Net income	**798,081**	837,621	**-5%**	1,739,986	-52%
Cash dividends paid	**201,405**	190,788	**6%**	166,501	15%
Capital expenditures	**2,448,140**	2,207,269	**11%**	2,364,686	-7%
Net cash provided by operating activities	**3,128,558**	1,864,633	**68%**	3,039,912	-39%
Average common shares outstanding – diluted (thousands)	**193,158**	192,468	**0%**	192,134	0%
At End of Year					
Working capital	**$ 619,783**	$ 1,194,087	**-48%**	$ 958,818	25%
Net property, plant and equipment	**10,367,847**	9,065,088	**14%**	7,727,718	17%
Total assets	**14,233,243**	12,756,359	**12%**	11,149,098	14%
Long-term debt	**939,350**	1,353,183	**-31%**	1,026,222	32%
Stockholders' equity	**8,199,550**	7,346,026	**12%**	6,278,945	17%
Per Share of Common Stock					
Income from continuing operations – diluted	**$ 4.13**	$ 3.85	**7%**	$ 9.08	-58%
Net income – diluted	**4.13**	4.35	**-5%**	9.06	-52%
Cash dividends paid	**1.05**	1.00	**5%**	.875	14%
Stockholders' equity	**42.52**	38.44	**11%**	32.92	17%
Net Crude Oil and Gas Liquids					
Produced – barrels per day	**126,927**	131,839	**-4%**	118,254	11%
United States	**20,114**	17,053	**18%**	10,668	60%
Canada	**30,801**	32,043	**-4%**	37,902	-15%
Malaysia	**66,897**	76,322	**-12%**	57,403	33%
Other International	**9,115**	6,421	**42%**	12,281	-48%
Net Natural Gas Sold – thousands of cubic feet per day	**356,801**	187,266	**91%**	55,518	237%
United States	**53,037**	54,255	**-2%**	45,785	18%
Canada	**85,563**	54,857	**56%**	1,910	2,772%
Malaysia	**212,692**	74,653	**185%**	1,399	5,236%
United Kingdom	**5,509**	3,501	**57%**	6,424	-46%
Crude Oil Refined – barrels per day	**219,864**	230,647	**-5%**	219,227	5%
United States	**141,023**	134,022	**5%**	121,706	10%
United Kingdom	**78,841**	96,625	**-18%**	97,521	-1%
Petroleum Products Sold – barrels per day	**536,757**	536,474	**0%**	539,000	0%
United States	**450,100**	432,700	**4%**	427,490	1%
United Kingdom	**86,657**	103,774	**-16%**	111,510	-7%
Stockholder and Employee Data					
Common shares outstanding (thousands)*	**192,836**	191,115	**1%**	190,714	0%
Number of stockholders of record*	**2,363**	2,490	**-5%**	2,564	-3%
Number of employees*	**8,994**	8,369	**7%**	8,277	1%
Average number of employees	**8,673**	8,157	**6%**	7,890	3%

*At December 31.

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, owns two petroleum refineries and two ethanol production facilities in the United States and one petroleum refinery in the United Kingdom. The Company operates a growing retail marketing gasoline station chain 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 and the United Kingdom. The Company has announced its intention to sell its three oil refineries and the U.K. marketing assets during 2011. Murphy is headquartered in El Dorado, Arkansas, and has over 8,000 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 Kuala Lumpur, Malaysia; St. Albans, England; Pointe-Noire, Republic of the Congo; Jakarta, Indonesia; Perth, Western Australia; and Erbil in the Kurdistan region of Iraq.

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 refining and marketing of petroleum products in the United States. It is headquartered in El Dorado, Arkansas. Refineries in Meraux, Louisiana, and Superior, Wisconsin, provide petroleum products to high-volume, low-cost Murphy USA® branded gasoline stations located on-site at Walmart Supercenters and at stand-alone Murphy Express® locations in 22 states, primarily in the South and Midwest. Murphy Oil USA also operates a network of 12 Company-owned terminals and two leased terminals. These terminals, along with a number of third-party terminals, supply fuel to retail and wholesale stations in 26 states and to various asphalt and marine fuel customers. A subsidiary acquired an ethanol production facility in Hankinson, North Dakota, in October 2009. In 2010, the Company purchased an ethanol production facility in Hereford, Texas, that will be completed and operating in early 2011. The Company has announced its intention to sell the two refineries and certain associated marketing terminals in 2011.

Murco Petroleum Limited is engaged in refining and marketing of petroleum products in the United Kingdom. Headquartered near London, 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 in 2011.

Offices

El Dorado, Arkansas	St. Albans, Hertfordshire, England	Jakarta, Indonesia
Houston, Texas	Kuala Lumpur, Malaysia	Perth, Western Australia, Australia
Washington, D.C.	Pointe-Noire, Republic of the Congo	Erbil, Iraq (Kurdistan region)
Calgary, Alberta, Canada		

Dear Fellow Shareholders

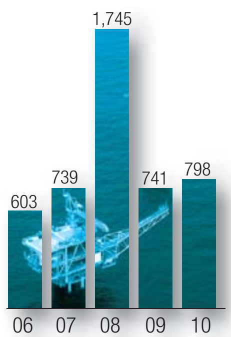
The year of 2010 was one of contrasts: economic recovery, yet lingering high unemployment in the U.S.; and a rebound in global oil demand and prices, offset by North American natural gas oversupply and resulting price declines. Increased industry activity was overtaken by the tragic events of the BP Macondo incident in April. Since then, business in the Gulf of Mexico (GOM) has been at a standstill absent a clear regulatory way to proceed. We reacted quickly and moved our contracted deepwater rig to Africa soon after the incident. With the preponderance of our upstream investments outside the U.S., we have fared well and continue to drive our growth profile forward. Whether it is economic uncertainty or political ambiguity, our Company is resilient, fiscally disciplined and well positioned to survive and prosper in these times. Our diversified global portfolio, weighted to oil production, provided solid returns in light of the strong oil price environment. Production for 2010 was 14% over the prior year and reserve replacement was a healthy 124%. Net income for 2010 totaled $798.1 million ($4.13 per share), down slightly from 2009 as a nonrecurring gain on disposal of Ecuador operations in the prior year more than offset improvements in both our upstream and downstream business segments. We continued our tradition of financial discipline and ended the year with a debt-to-capital-employed ratio of 10.3%. Our strong balance sheet provides the flexibility necessary to act on value-added opportunities or manage a significant development project.

Exploration and Production Annual production for 2010 averaged 186,400 barrels of oil equivalent per day with a 68% oil weighting. New contributions for the year came from initial phase development of our North American resource plays at Tupper (100%) in British Columbia and from the Eagle Ford Shale (EFS) area (95%) of South Texas, plus ramp-up of the Azurite field (50%), offshore Republic of the Congo, and Malaysia projects in Sarawak (85%) and at Kikeh (80%).

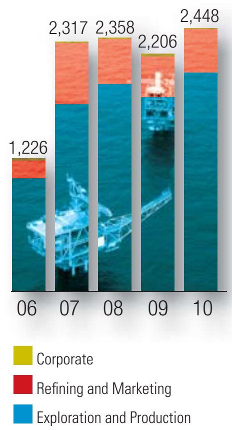
The growth profile will continue in 2011. In December, our Board sanctioned the first phase of oil development in the EFS, and start-up of the Tupper West gas plant, with a capacity of 180 million cubic feet per day, occurs this month. Resumption of activity in the GOM remains a question mark and has an impact on our production profile in that area.

Sanction of a number of development projects is expected throughout the year. In Malaysia, this includes oil developments at Patricia, South Acis and Serendah in the Sarawak blocks (85%) along with Siakap North (40%) in Block K. A floating LNG development at Rotan (80%) in Block H is also under consideration. In the U.S., we will see sanction of the second oil development area in the EFS. At the Seal heavy oil project (100%) in northern Alberta, we continue an active primary development drilling program and are encouraged with production rates from recent wells. An Enhanced Oil Recovery (EOR) pilot kicked off in late 2010 at Seal. We are evaluating the effectiveness of both polymer flooding and steam stimulation to unlock the massive heavy oil resource in place on our acreage. Results of the pilot work are expected in 2011 and we will be submitting applications for field development plans.

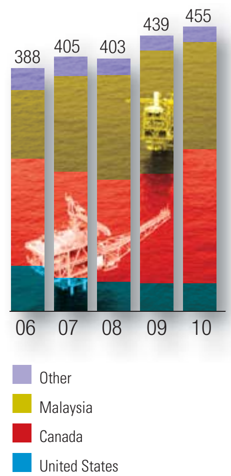
Income from Continuing Operations
(Millions of dollars)



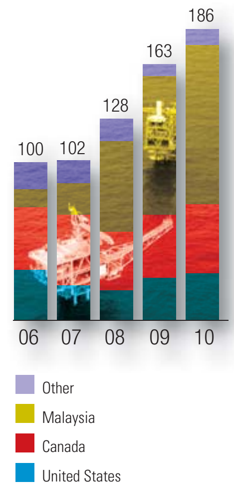
Capital Expenditures by Function
(Millions of dollars)



Estimated Net Proved Hydrocarbon Reserves
(Millions of oil equivalent barrels)



Net Hydrocarbons Produced
(Thousands of oil equivalent barrels)



A fourth play was added to our North American resource portfolio with new acreage in southern Alberta targeting the oil prospective Exshaw/Bakken formation. This will be actively appraised in 2011. Three of our four resource plays are oil focused, which is in line with our targeted portfolio balance and provides flexibility to our program as we are able to shift our focus between oil and gas as value points open.

We saw a meaningful resumption of our exploration program in 2010, with a focus on testing a dozen or more exploratory prospects per year. We ended up the year drilling 13 wildcat wells in six countries and started with some early successes with an oil discovery in DeSoto Canyon Block 4 (64.17%) in the GOM and two gas discoveries in Malaysia at Patricia and Dolfin. Our non-operated Deep Blue prospect (9.38%) in the GOM was suspended due to the moratorium. In Republic of the Congo, we failed to find the volumes sought in three wells and are now looking at tie-back options for those reserves found. Our first well, Caracara (100%), in the untested play offshore Suriname, failed to find pay and we plan to drill a second prospect to test further targets. We are currently drilling the Lengkuas well (28.33%) on the Semai II block in Indonesia.

The current year will include an active drilling program with exploration wells planned for Indonesia, Suriname, Congo, Brunei, and depending on rig availability, Kurdistan and Australia.

Refining and Marketing In July of last year, our Board approved a plan to offer for sale the U.S. refining and U.K. downstream businesses. We simply lack the competitive size and scale to grow this capital intensive business and can redeploy those funds where we have strong growth opportunities. The divestiture process is ongoing and remains on track to exit those businesses this year.

Strong U.S. retail margins in the middle part of 2010 helped deliver the second best annual income for that business. During the year, 51 new stations were built bringing the total number of retail outlets to 1,099 at year-end. Expansion of this network will continue with 55 stations budgeted for construction in 2011. This top quartile business will continue on course this year while exploring ways to significantly grow and lead the competition.

David M. Wood
President and Chief Executive Officer

In the biofuels business, we fully integrated the Hankinson ethanol plant into our operation and averaged more than 115 million gallons per year of ethanol production—5% over nameplate capacity—in its first full year of operation. The plant contributed solid financial returns to the downstream business. In September, we concluded the acquisition of the partially completed Hereford ethanol facility and plan to complete construction, and initiate start-up by the end of the first quarter 2011. We welcome a new community of dedicated and enthusiastic employees to the fold.

In Closing The vision for our Company remains clear. Exit of the U.S. refining and U.K. downstream businesses will realign the Company as an oil-weighted growth E&P entity with a best in class U.S. retail network. As the economic recovery matures and global energy demand rebounds, we are well positioned to grow and prosper. The combination of an active exploration program, which finds more hydrocarbons than produced each year and exposes the company to step-change growth, is matched with a meaningful North American oil-weighted resource program.

Ours is a "can do" Company that identifies, captures and operates the majority of our assets. We have a strong and very capable team working to make us better every day.

I would like to recognize one of our employees who is retiring after 41 years of service. Steve Cossé has been our General Counsel since 1991 and he provided an invaluable contribution to our success; we all wish him well in his retirement.

I appreciate the support you have shown us over the past year and with your continued backing, we look toward the promise of 2011 and moving our Company forward to new heights.

David M. Wood
President and Chief Executive Officer

February 17, 2011
El Dorado, Arkansas

Exploration and Production Statistical Summary

	2010	2009	2008	2007	2006	2005	2004
Net crude oil, condensate and natural gas liquids production – barrels per day							
United States	**20,114**	17,053	10,668	12,989	21,112	25,897	19,314
Canada – light	**43**	18	46	596	443	563	650
heavy	**5,988**	6,813	8,484	11,524	12,613	11,806	5,838
offshore	**11,497**	12,357	16,826	18,871	14,896	23,124	25,407
synthetic	**13,273**	12,855	12,546	12,948	11,701	10,593	11,794
Malaysia	**66,897**	76,322	57,403	20,367	11,298	13,503	11,885
United Kingdom	**3,295**	3,361	4,869	5,281	7,146	7,992	11,011
Republic of the Congo	**5,820**	1,743	–	–	–	–	–
Continuing operations	**126,927**	130,522	110,842	82,576	79,209	93,478	85,899
Discontinued operations	**–**	1,317	7,412	8,946	8,608	7,871	10,841
Total liquids produced	**126,927**	131,839	118,254	91,522	87,817	101,349	96,740
Net crude oil, condensate and natural gas liquids sold – barrels per day							
United States	**20,114**	17,053	10,668	12,989	21,112	25,897	19,314
Canada – light	**43**	18	46	596	443	563	650
heavy	**5,988**	6,813	8,484	11,524	12,613	11,806	5,838
offshore	**11,343**	12,455	16,690	18,839	15,360	22,443	26,306
synthetic	**13,273**	12,855	12,546	12,948	11,701	10,593	11,794
Malaysia	**68,975**	72,575	61,907	16,018	11,986	13,818	11,020
United Kingdom	**4,177**	2,445	5,739	5,218	6,678	8,303	10,924
Republic of the Congo	**5,428**	973	–	–	–	–	–
Continuing operations	**129,341**	125,187	116,080	78,132	79,893	93,423	85,846
Discontinued operations	**–**	1,162	7,774	9,470	10,349	9,821	6,520
Total liquids sold	**129,341**	126,349	123,854	87,602	90,242	103,244	92,366
Net natural gas sold – thousands of cubic feet per day							
United States	**53,037**	54,255	45,785	45,139	56,810	70,452	88,621
Canada	**85,563**	54,857	1,910	9,922	9,752	10,323	13,972
Malaysia – Sarawak	**154,535**	28,070	–	–	–	–	–
– Kikeh	**58,157**	46,583	1,399	–	–	–	–
United Kingdom	**5,509**	3,501	6,424	6,021	8,700	9,423	6,859
Continuing operations	**356,801**	187,266	55,518	61,082	75,262	90,198	109,452
Discontinued operations	**–**	–	–	–	–	–	30,760
Total natural gas sold	**356,801**	187,266	55,518	61,082	75,262	90,198	140,212
Net hydrocarbons produced – equivalent barrels[1] per day	**186,394**	163,050	127,507	101,702	100,361	116,382	120,109
Estimated net hydrocarbon reserves – million equivalent barrels[1,2]	**455.2**	439.2	402.8	405.1	388.3	353.6	385.6
Weighted average sales prices[3]							
Crude oil, condensate and natural gas liquids – dollars per barrel							
United States	**$76.31**	60.08	95.74	65.57	57.30	47.48	35.35
Canada[4] – light	**75.48**	64.24	70.37	50.98	50.45	44.27	32.96
heavy	**49.89**	40.45	59.05	32.84	25.87	21.30	20.26
offshore	**76.87**	58.19	96.69	69.83	62.55	51.37	36.60
synthetic	**77.90**	61.49	100.10	74.35	63.23	58.12	40.35
Malaysia[5]	**60.97**	55.51	87.83	74.58	51.78	46.16	41.35
United Kingdom	**77.95**	61.31	90.16	68.38	64.30	52.83	36.82
Republic of the Congo	**74.87**	69.04	–	–	–	–	–
Natural gas – dollars per thousand cubic feet							
United States	**4.52**	4.05	9.67	7.38	7.76	8.52	6.45
Canada[4]	**4.23**	3.09	6.40	6.34	6.49	7.88	5.64
Malaysia – Sarawak	**5.31**	4.05	–	–	–	–	–
– Kikeh	**0.23**	0.23	0.23	–	–	–	–
United Kingdom[4]	**7.01**	5.04	10.98	7.54	7.34	5.80	4.52

[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 production sharing contracts for Blocks K and SK 309.

Refining and Marketing Statistical Summary

	2010	2009	2008	2007	2006	2005	2004
Crude capacity[1] of refineries – barrels per stream day	**295,000**	268,000	268,000	268,000	192,400	192,400	192,400
Refinery inputs – barrels per day							
Crude – Meraux, Louisiana	**106,482**	101,864	95,126	106,446	55,129	73,371	101,644
Superior, Wisconsin	**34,541**	32,158	26,580	32,737	34,066	34,768	31,598
Milford Haven, Wales	**78,841**	96,625	97,521	36,000	30,036	26,983	31,033
Other feedstocks	**11,518**	14,317	23,300	10,805	6,423	9,131	12,170
Total refinery inputs	**231,382**	244,964	242,527	185,988	125,654	144,253	176,445
Refinery yields – barrels per day							
United States – Gasoline	**61,128**	62,534	54,020	61,998	37,690	45,287	58,899
Kerosine	**11,068**	10,670	8,759	871	812	5,001	4,678
Diesel and home heating oils	**41,305**	40,761	41,658	52,893	30,829	34,561	51,775
Residuals	**18,082**	15,786	14,585	15,269	11,414	15,019	13,633
Asphalt, LPG and other	**14,802**	10,845	9,065	13,202	9,893	10,406	10,191
Fuel and loss	**834**	1,409	1,852	1,999	1,260	722	614
Total United States	**147,219**	142,005	129,939	146,232	91,898	110,996	139,790
United Kingdom – Gasoline	**20,889**	26,902	32,290	12,397	10,624	9,582	9,764
Kerosine	**11,374**	13,789	15,065	4,500	4,255	2,804	3,056
Diesel and home heating oils	**25,995**	34,619	33,868	14,218	11,308	13,974	14,450
Residuals	**8,296**	10,388	12,585	3,641	3,830	3,212	3,812
Asphalt, LPG and other	**14,799**	13,735	15,750	4,344	2,962	2,862	4,502
Fuel and loss	**2,810**	3,526	3,030	656	777	823	1,071
Total United Kingdom	**84,163**	102,959	112,588	39,756	33,756	33,257	36,655
Total refinery yields	**231,382**	244,964	242,527	185,988	125,654	144,253	176,445
Average cost of crude inputs to refineries – dollars per barrel							
United States	**$ 77.51**	59.71	96.46	69.40	59.54	49.73	40.00
United Kingdom	**75.10**	62.90	100.61	81.53	66.66	56.15	39.60
Petroleum products sold – barrels per day							
U.S. Manufacturing – Gasoline	**68,627**	64,128	54,020	61,998	37,690	45,287	58,899
Kerosine	**11,068**	10,670	8,759	871	812	5,001	4,678
Diesel and home heating oils	**41,305**	41,019	41,658	52,893	30,829	34,561	51,775
Residuals	**18,015**	15,501	14,834	15,463	11,697	15,330	13,699
Asphalt, LPG and other	**9,655**	9,124	7,161	9,672	8,631	8,946	9,471
	148,670	140,442	126,432	140,897	89,659	109,125	138,522
U.S. Marketing – Gasoline	**333,182**	319,551	314,244	299,355	265,809	232,534	207,169
Kerosine	**11,449**	11,918	4,721	2,065	1,836	5,669	4,811
Diesel and other	**77,799**	76,606	86,530	90,113	62,628	60,235	66,651
	422,430	408,075	405,495	391,533	330,273	298,438	278,631
U.S. intracompany elimination – Gasoline	**(68,627)**	(64,128)	(54,020)	(61,998)	(37,690)	(45,287)	(58,899)
Kerosine	**(11,068)**	(10,670)	(8,759)	(871)	(812)	(5,001)	(4,678)
Diesel and other	**(41,305)**	(41,019)	(41,658)	(52,893)	(30,829)	(34,561)	(51,775)
	(121,000)	(115,817)	(104,437)	(115,762)	(69,331)	(84,849)	(115,352)
Total United States	**450,100**	432,700	427,490	416,668	350,601	322,714	301,801
United Kingdom – Gasoline	**23,085**	30,007	34,125	14,356	12,425	12,739	11,435
Kerosine	**11,387**	12,954	14,835	4,020	3,619	2,410	2,756
Diesel and home heating oils	**29,710**	35,721	34,560	14,785	11,803	14,910	14,649
Residuals	**7,885**	10,560	12,744	3,728	3,825	3,242	4,062
LPG and other	**14,590**	14,532	15,246	4,213	2,998	2,240	4,205
Total United Kingdom	**86,657**	103,774	111,510	41,102	34,670	35,541	37,107
Total petroleum products sold	**536,757**	536,474	539,000	457,770	385,271	358,255	338,908
Branded retail outlets[1]							
United States – Murphy USA®	**1,001**	996	992	971	987	864	752
Murphy Express®	**98**	52	33	2	–	–	–
Other	**116**	121	129	153	177	337	375
Total United States	**1,215**	1,169	1,154	1,126	1,164	1,201	1,127
United Kingdom	**451**	453	454	389	402	412	358
Unit margins per barrel:							
United States refining[2]	**$ 0.23**	0.75	(1.48)	5.11	(0.24)	1.02	0.12
United Kingdom refining and marketing	**(1.47)**	(0.28)	3.41	(1.48)	4.43	4.81	3.51
United States retail marketing:							
Fuel margin per gallon[3]	**$ 0.114**	0.083	0.165	0.103	0.104	0.115	0.102
Gallons sold per store month	**306,646**	312,493	324,223	294,784	285,665	268,277	245,245
Merchandise sales revenue per store month	**$153,530**	137,623	110,943	97,523	80,598	66,516	56,368
Merchandise margin as a percentage of merchandise sales	**13.1%**	12.5%	13.5%	13.2%	13.3%	12.8%	12.1%

[1]At December 31. [2]Represents refinery sales realizations less cost of crude and other feedstocks and refinery operating and depreciation expenses. [3]Represents net sales prices for fuel less purchased cost of fuel.

Board of Directors

William C. Nolan, Jr.
Partner, Nolan & Alderson, Attorneys,
El Dorado, Arkansas.
Director since 1977.
Chairman of the Board, ex-officio member
of all other committees

David M. Wood
President and Chief Executive Officer,
Murphy Oil Corporation,
El Dorado, Arkansas.
Director since January 2009.
Committees: Executive

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

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

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

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

Neal E. Schmale
President and Chief Operating Officer,
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
Senior Vice President,
South East Asia

Derek M. Stewart
Senior Vice President,
U.S., Latin America, West Africa
and Europe Operations

Sam Algar
Vice President, Worldwide Exploration

Keith S. Caldwell
Vice President, Finance and Administration

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, Joint Ventures and Business Development

Dennis Ward
Vice President, Finance

Mindy K. West
Vice President and Treasurer

Paul Christensen
Controller

Georg R. McKay
Secretary

Murphy Oil USA, Inc.

Engages in manufacturing and marketing of petroleum and ethanol products 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

Thomas McKinlay
President

Stephen F. Hunkus
Vice President, World Wide Refining

Ernest C. Cagle
Vice President, Refining Support

Marn Cheng
Vice President, Renewable Fuels

Walter K. Compton
Vice President and General Counsel

Mindy K. West
Vice President and Treasurer

John W. Eckart
Vice President and Controller

John A. Moore
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 Kelly
Managing Director

Jeremy Clarke
Marketing Director

Bernard Pouille
Supply 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)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2010**

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, 2010) – $9,503,357,000.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2011 was 192,853,864.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 11, 2011 have been incorporated by reference in Part III herein.

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MURPHY OIL CORPORATION

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PART I

Item 1. BUSINESS

Summary

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

The Company was originally incorporated in Louisiana in 1950 as Murphy Corporation. It was reincorporated in Delaware in 1964, at which time it adopted the name Murphy Oil Corporation, and was reorganized in 1983 to operate primarily as a holding company of its various businesses. Its operations are classified into two business activities: (1) “Exploration and Production” and (2) “Refining and Marketing.” For reporting purposes, Murphy’s exploration and production activities are subdivided into six geographic segments, including the United States, Canada, Malaysia, the United Kingdom, Republic of the Congo and all other countries. Murphy’s refining and marketing activities are subdivided into segments for United States Manufacturing, United States Marketing and the United Kingdom. Additionally, “Corporate” activities include interest income, interest expense, foreign exchange effects and administrative costs not allocated to the segments.

The information appearing in the 2010 Annual Report to Security Holders (2010 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 17 through 31, F-13 and F-14, F-36 through F-42 and F-44 of this Form 10-K report and on pages 5 and 6 of the 2010 Annual Report.

At December 31, 2010, Murphy had 8,994 employees, including 3,460 full-time and 5,534 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 2010, Murphy’s principal exploration and production activities were conducted in the United States by wholly owned Murphy Exploration & Production Company – USA (Murphy Expro USA), in Malaysia, Republic of the Congo, Indonesia, Suriname, Australia, Brunei and the Kurdistan region of Iraq by wholly owned Murphy Exploration & Production Company – International (Murphy Expro International) and its subsidiaries, in Western Canada and offshore Eastern Canada by wholly owned Murphy Oil Company Ltd. (MOCL) and its subsidiaries, and in the U.K. North Sea and the Atlantic Margin by wholly owned Murphy Petroleum Limited. Murphy’s crude oil and natural gas liquids production in 2010 was in the United States, Canada, Malaysia, the United Kingdom and Republic of the Congo; its natural gas was produced and sold in the United States, Canada, Malaysia and the United Kingdom. MOCL owns a 5% undivided interest in Syncrude Canada Ltd. in northern Alberta, one of the world’s largest producers of synthetic crude oil.

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 2010 averaged 126,927 barrels per day, a decrease of 4% compared to 2009. The decrease was primarily due to lower 2010 oil production at the Kikeh field, offshore Sabah Malaysia. The Company’s worldwide sales volume of natural gas averaged almost 357 million cubic feet (MMCF) per day in 2010, up more than 90% from 2009 levels. The higher natural gas sales volume in 2010 was primarily attributable to increased natural gas production in three areas, the most significant of which was in Blocks SK 309/311, offshore Sarawak Malaysia. The other two primary growth areas for natural gas production in 2010 were at Tupper in British Columbia, Canada, and at the Kikeh field, offshore Sabah Malaysia. Total worldwide 2010 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 186,394 barrels per day, an increase of 14% compared to 2009.

Total production in 2011 is currently expected to average between 200,000 and 210,000 barrels of oil equivalent per day. The projected production increase of between 7% and 13% in 2011 is primarily related to new natural gas production at the Tupper West area in Western Canada that commenced in February 2011. These volumes will more than offset anticipated production declines in 2011 at fields in the Gulf of Mexico, and lower volumes associated with downtime for well maintenance at the Kikeh field, offshore Malaysia, and downtime for equipment maintenance at Terra Nova, offshore Newfoundland. Production levels in the Gulf of Mexico for Murphy, and likely many other companies, are being adversely affected by the inability to obtain government permits for drilling and well maintenance operations following the Macondo well blowout and oil spill by another company in 2010.

<u>United States</u>

In the United States, Murphy has production of oil and/or natural gas from six fields operated by the Company and five fields operated by others. The U.S. producing fields at December 31, 2010 include eight in the deepwater Gulf of Mexico, two onshore in Louisiana, and the Eagle Ford Shale area of South Texas. The Company produced approximately 20,100 barrels of oil per day and 53 million cubic feet of natural gas per day in the U.S. in 2010. These amounts represented 16% of the Company's total worldwide oil and 15% of worldwide natural gas production volumes. During 2010, over 60% of total U.S. hydrocarbon production was produced at two operated Gulf of Mexico fields – Thunder Hawk and Medusa. Murphy has a 37.5% working interest in the Thunder Hawk field in Mississippi Canyon Block 734. Oil and natural gas production commenced at Thunder Hawk in July 2009 and during 2010 averaged about 9,800 barrels of oil per day and 9 MMCF per day. Production in 2011 at Thunder Hawk is expected to average approximately 5,500 barrels of oil per day and 8 MMCF per day. The lower 2011 production at Thunder Hawk is due to well decline and the inability to perform drilling operations since the Macondo incident in 2010. Proved oil and natural gas reserves at Thunder Hawk at year-end 2010 were 4.7 million barrels and 7.3 billion cubic feet, respectively. The Company holds a 60% interest at Medusa in Mississippi Canyon Blocks 538/582, which produced total daily oil and natural gas of about 5,500 barrels and 5 MMCF, respectively, in 2010. Production from Medusa is expected to continue to decline in 2011 and should average 4,300 barrels of oil and about 4 MMCF of natural gas on a daily basis. At December 31, 2010, the Medusa field has total proved oil and natural gas reserves of approximately 5.7 million barrels and 8.7 billion cubic feet, respectively. The Company has acquired rights to significant acreage in South Texas in the Eagle Ford Shale unconventional oil and gas play. The Company has drilled 17 wells through year-end 2010 of which 11 wells are capable of producing and the remaining six wells are pending completion. Initial well results in the Eagle Ford play have been encouraging. Current plans are to drill approximately 40 wells here in 2011. Total daily net production in 2011 in the Eagle Ford area is expected to amount to 4,300 barrels of oil and 13 MMCF of gas. Total U.S. oil and natural gas reserves at December 31, 2010 were 26.6 million barrels and 90.8 billion cubic feet, respectively.

Subsequent to the Macondo incident in April 2010, the process for obtaining drilling and other operational permits in the Gulf of Mexico has become uncertain. The changes to the permitting process, as well as operational procedures, are expected to cause delays and more expense associated with drilling operations in the Gulf of Mexico. Therefore, the Company anticipates that its production, and likely many other companies' production, will decline in the Gulf of Mexico during 2011 and possibly into 2012. The Company is unable to predict to what extent these delays and new processes will ultimately impact its operations in the Gulf of Mexico.

<u>Canada</u>

In Canada, the Company owns an interest in three significant nonoperated 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 has historically been 12.0%. 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 to 10.475% effective January 1, 2011. The Company has recorded cumulative expense of $102.1 million through 2010 based on the anticipated settlement of the working interest reduction. The Company made a settlement payment to certain Terra Nova partners in January 2011 for the value of oil sold since about December 2004 related to the difference between the Company's 10.475% ultimate working interest and its original 12.0% interest.

Oil production in 2010 was about 6,300 barrels of oil per day at Hibernia and 5,200 barrels per day at Terra Nova. Hibernia production increased slightly in 2010 due to higher gross production mostly offset by a higher royalty rate, while production at Terra Nova declined primarily due to lower gross production. Oil production for 2011 at Hibernia is anticipated to be approximately 5,900 barrels per day and production at Terra Nova is expected to decline to approximately 3,000 barrels per day due to a scheduled 105 day turnaround. Total proved oil reserves at December 31, 2010 at Hibernia and Terra Nova were approximately 9.5 million barrels and 6.4 million barrels, respectively.

Murphy owns a 5% undivided interest in Syncrude Canada Ltd., a joint venture located about 25 miles north of Fort McMurray, Alberta. Syncrude utilizes its assets, which include three coking units, to extract bitumen from oil sand deposits and to upgrade this bitumen into a high-value synthetic crude oil. Production in 2010 was about 13,300 barrels of synthetic crude oil per day and is expected to average about 14,000 barrels per day in 2011. The SEC issued revised reserve rules in 2009 that permitted the reporting of proved reserves for synthetic oil operations beginning at year-end 2009. Prior to that time, the SEC considered Syncrude to be a mining operation rather than a conventional oil operation and therefore, did not allow the Company to include Syncrude's reserves in its total proved oil reserves. Total proved reserves for Syncrude at year-end 2010 were 129.2 million barrels.

Daily production in 2010 in the WCSB averaged about 6,000 barrels of mostly heavy oil and about 85 MMCF of natural gas. Through 2010, the Company has acquired approximately 130,000 net acres of mineral rights in northeastern British Columbia in areas named Tupper and Tupper West. First production of natural gas occurred at Tupper in December 2008. The Company's Board of Directors sanctioned development of Tupper West in 2009 and first production of natural gas occurred in February 2011. Oil and natural gas daily production for 2011 in Western Canada, excluding Syncrude, is expected to be about 8,600 barrels and 180 MMCF, respectively, with the increase in natural gas volumes primarily due to start-up of production at Tupper West in February 2011. Total Western Canada proved oil and natural gas reserves at December 31, 2010, excluding Syncrude, were 16.9 million barrels and 321.7 billion cubic feet, respectively.

During 2010, the Company added approximately 147,000 gross acres of land in Southern Alberta that is prospective for light oil. The Company began drilling operations on this acreage in early 2011. Additional wells are planned throughout 2011 to test various formations.

Malaysia

In Malaysia, the Company has majority interests in six separate production sharing contracts (PSCs). The Company serves as the operator of all these areas, which cover approximately 6.7 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 planned for future development. About 5,300 barrels of oil per day were produced in 2010 at Block SK 309/311, mostly at the West Patricia field. Oil production in 2011 at fields in Blocks SK 309/311 is anticipated to total about 5,300 barrels of oil per day. The Company has a gas sales contract for the Sarawak area with PETRONAS, the Malaysian state-owned oil company, and has prepared a multi-phase development plan for several natural gas discoveries on these blocks. The gas sales contract allows for gross sales volumes of up to 250 million cubic feet per day through 2014, with an option to extend for seven years at 250 million cubic feet per day or for ten years at 350 million cubic feet per day. Total natural gas sales volume offshore Sarawak was about 155 MMCF per day during 2010 (gross 210 MMCF per day) following gas production start-up in September 2009. Sarawak natural gas sales volumes are anticipated to be approximately 171 MMCF per day in 2011. Total proved reserves of oil and natural gas at December 31, 2010 for Blocks SK 309/311 were 5.8 million barrels and 348.1 billion cubic feet, respectively.

The Company made a major discovery at the Kikeh field in deepwater Block K, offshore Sabah, in 2002 and added another important discovery at Kakap in 2004. Several additional discoveries have been made in Block K at other areas. In 2006, the Company relinquished a portion of Block K and was granted a 60% interest in an extension of a portion of Block K. Total gross acreage held by the Company in Block K as of December 31, 2010 was 1.01 million acres. The Company retained its 80% interest at Kikeh, Kakap and other discoveries in Block K. First oil production from Kikeh began in August 2007, less than five years after the initial discovery. Production volumes at Kikeh averaged 61,600 barrels of oil per day during 2010. Oil production at Kikeh is anticipated to average approximately 57,000 barrels per day for 2011. 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 million cubic feet per day through June 2012. Natural gas production at Kikeh began in late 2008, and 2010 production totaled approximately 58 MMCF per day. Daily gas production in 2011 at Kikeh is expected to be similar to 2010 levels. The Kakap field in Block K is operated by another company. This field is being jointly developed with the Gumusut field owned by others. Kakap development activities continued during 2010 and first production is anticipated in 2013. The Siakap North oil discovery was made in 2009; the field will be a unitized development and appraisal commenced in 2010. Total proved reserves booked in Block K as of year-end 2010 were 92.6 million barrels of oil and 85.9 billion cubic feet of natural gas.

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. The Company also has an interest in deepwater Block H offshore Sabah. In early 2007, the Company announced a significant natural gas discovery at the Rotan well in Block H. In early 2008, the Company followed up Rotan with a discovery at Biris. In March 2008, the Company renewed the contract for Block H at a 60% interest while retaining 80% interest in the Rotan and Biris discoveries. In 2010 another natural gas discovery was made in Block H at Dolfin. Total gross acreage held at year-end 2010 by the Company in Block H was 1.99 million acres.

Murphy has a 75% interest in gas holding agreements for Kenarong and Pertang discoveries made in Block PM 311, located offshore peninsular Malaysia. Development options are being studied for these discoveries. Murphy relinquished its remaining interests in Block PM 311 and all of adjacent Block PM 312 in 2007.

The Company was awarded interests in two PSCs covering deepwater Blocks L (60%) and M (70%) in 2003. On April 7, 2010, the PSCs for Blocks L and M were terminated following execution of an Exchange of Letters between Malaysia and the Sultanate of Brunei on March 16, 2009. See further discussion about this exploration area in the Brunei section on page 5.

United Kingdom

Murphy produces oil and natural gas in the United Kingdom sector of the North Sea. Total 2010 production in the U.K. amounted to about 3,300 barrels of oil per day and 5 MMCF of natural gas per day. Total 2011 daily production levels in the U.K. are anticipated to average about 4,000 barrels of oil and 5 MMCF of natural gas. Total proved reserves in the U.K. at December 31, 2010 were 10.9 million barrels of oil and 31.4 billion cubic feet of natural gas.

Republic of the Congo

The Company has interests in Production Sharing Agreements (PSA) covering two offshore blocks in Republic of the Congo – Mer Profonde Sud (MPS) and Mer Profonde Nord (MPN). The Company's interests cover approximately 1.33 million gross acres with water depths ranging from 490 to 6,900 feet, and the Company serves as operator of both blocks. In 2005, Murphy made an oil discovery at Azurite Marine #1 in the southern block, MPS. The Company successfully followed up the Azurite discovery with other appraisal wells. First oil production occurred at the Azurite field in August 2009. Total oil production in 2010 averaged 5,800 barrels per day at Azurite. Anticipated production in 2011 is 8,300 barrels per day, with the increase caused by additional producing wells in late 2010. Total proved oil reserves at the Azurite field as of December 31, 2010 were 10.1 million barrels. In late 2007, the Company sold down its interest in the MPS block, including the Azurite field, from 85% to 50%. Sale proceeds received were $94.5 million, including contingent amounts earned in 2009 upon achieving certain financial and operating goals for Azurite field development. In addition, the Company received a partial carry for costs for two exploration wells in MPS that were drilled in 2009, one of which was a discovery known as Turquoise Marine. Two subsequent wells at Turquoise and one at another prospect were unsuccessful. Further drilling activities are being planned for the Turquoise discovery area. A wildcat well drilled at Titane Marine in 2010 in the MPN block found accumulations of crude oil for which appraisal plans are pending. Development options are currently being studied. Other prospects in the MPN and MPS blocks are being evaluated and exploration wells are planned for 2011 and 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 are effective retroactive to October 1, 2010. Essentially, the PSC amendment calls for revised terms that will permit additional levels of crude oil production to be allocated to the accounts of the Company and its non-government partners in future periods. The Company is also required to pay a bonus to Republic of the Congo in connection with the PSA amendment.

Suriname

In June 2007, Murphy entered into a production sharing contract covering Block 37, offshore Suriname. Murphy operates this block and has a 100% working interest, subject to a potential reduction to 80% should the state oil company exercise its option. Block 37 covers approximately 2.16 million gross acres and has water depths ranging from 160 to 1,000 feet. In the acreage table on page 8, the Company has reflected net acreage for Suriname as if the state company's option will be exercised. The contract provides for a six-year exploration period with two phases. Phase I has a four-year period that requires the acquisition of 3D seismic and the drilling of two wells. The 3D seismic was shot in late 2008 and early 2009, and interpretation of this data occurred in 2009. The first exploration well was drilled in late 2010 and was unsuccessful. A second exploration well will be drilled in early 2011.

Australia

The Company acquired a 40% interest and operatorship of an exploration permit covering approximately 1.00 million gross acres in Block AC/P36 in the Browse Basin offshore northwestern Australia in November 2007. Three-dimensional seismic data was obtained in late 2007 and drilling of a commitment exploration well in late 2008 was unsuccessful. In November 2008, the Company acquired a 70% working interest and operatorship of a second Browse Basin exploration permit in Block WA-423-P. Murphy farmed down its interest in WA-423-P to 40% in the first quarter of 2009. This permit covers approximately 1.43 million gross acres and calls for a 3D seismic survey and one exploration well, which is expected to be drilled in 2011. In June 2009, the Company acquired a 70% interest and operatorship of Block NT/P80 in the Bonaparte Basin, offshore northwestern Australia. The block covers approximately 1.21 million gross acres and reprocessing of seismic covering the area has been completed. In 2010, the Company sold down its interest in this block to 40%.

Indonesia

In May 2008, the Company entered into a production sharing contract in Indonesia covering a 100% interest in the South Barito block in south Kalimantan on the island of Borneo. The block covers approximately 1.24 million gross acres. The 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. The contract requires relinquishment of 25% of acreage after three years and an additional 55% after six years. In November 2008, Murphy entered into a production sharing contract in the Semai II Block offshore West Papua. The Company has a 28% interest in the block which covers about 835,000 gross acres. The permit calls for a 3D seismic program and three exploration wells. The first exploration well in the Semai II Block was being drilled in early 2011. 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 geophysical and 3D seismic acquisition and processing. Murphy is the operator of the South Barito, Semai II and Wokam II concessions.

Brunei
In late 2010, the Company entered into two production sharing agreements for properties offshore Brunei. The Company has a 5% working interest in Block CA-1 and a 30% working interest in Block CA-2. These blocks cover a significant portion of acreage formerly held by the Company in Malaysia Blocks L and M. The Malaysian Production Sharing Contracts covering Blocks L and M were terminated in early 2010. The CA-1 and CA-2 blocks cover 1.45 million and 1.49 million gross acres, respectively.

Kurdistan region of Iraq
In late 2010, the Company finalized an agreement with the Kurdistan Regional Government in Iraq to acquire an interest in the Central Dohuk Block. The Company will operate and hold 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 plans to shoot seismic in 2011 with an exploration well to follow in 2012.

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

Total proved oil and gas reserves as of December 31, 2010 are presented in the following table.

	Proved Reserves		
	Oil	Synthetic Oil	Natural Gas
	(millions of barrels)		(billions of cubic feet)
Proved Developed:			
United States	15.8	–	67.0
Canada	28.6	119.1	210.1
Malaysia	66.5	–	277.5
United Kingdom	10.9	–	31.4
Republic of the Congo	7.4	–	–
Total proved developed	129.2	119.1	586.0
Proved Undeveloped:			
United States	10.8	–	23.8
Canada	4.2	10.1	116.8
Malaysia	31.9	–	156.5
United Kingdom	–	–	–
Republic of the Congo	2.7	–	–
Total proved undeveloped	49.6	10.1	297.1
Total proved	178.8	129.2	883.1

Proved Undeveloped Reserves
Murphy's proved undeveloped reserves at December 31, 2010 increased 7.0 million barrels of oil equivalent (MMBOE) from a year earlier. Approximately 33.6 MMBOE of proved undeveloped reserves were converted to proved developed reserves during 2010. The majority of the proved undeveloped reserves migration to the proved developed category occurred at the Sarawak gas fields and in the Tupper and Tupper West gas areas, as these areas had active development work ongoing during the year. The conversion of non-proved reserves to newly reported proved undeveloped reserves occurred at several areas including, but not limited to, the Tupper, Tupper West and Eagle Ford Shale areas and the Kikeh field. During 2010, there were 15.9 MMBOE of positive revisions for proved undeveloped reserves. The majority of proved undeveloped reserves additions associated with revisions of previous estimates were the result of development drilling and well performance at the Kikeh field in Malaysia. The Company spent $399 million in 2010 to convert proved undeveloped reserves to proved developed reserves. The Company expects to spend about $961 million in 2011, $346 million in 2012 and $136 million in 2013 to move currently undeveloped proved reserves to the developed category. The higher level of spend in 2011 is caused by significant drilling in the year at Kikeh field and in the Tupper and Tupper West areas. 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, 2010, 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 in Malaysia, and an oil development at Kakap, offshore Sabah Malaysia. Total proved undeveloped reserves associated with various development projects at December 31, 2010 were approximately 109 million barrels of oil equivalents, which is 24% 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. Two 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 2% of the Company's total proved reserves at year-end 2010. 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 approximately 3% of the Company's total proved reserves at year-end 2010. This non-operated project will take longer than five years to develop due to long lead-time equipment required to complete the development process.

Murphy Oil's Reserves Processes and Policies

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

The Company employs a Manager of Corporate Reserves (Manager) who is independent of the Company's oil and gas management. The Manager reports to a Senior Vice President of Murphy Oil Corporation, who in turn reports directly to the President of the Company. 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 internal 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 does not rely on independent reserves consultants to determine its proved reserves reported in this 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.

Qualifications of Manager of Corporate Reserves

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

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-38 and F-39 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, 2010 are shown on page 5 of the 2010 Annual Report. In 2010, 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 23 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-36 through F-44 of this Form 10-K report.

At December 31, 2010, 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	9	7	267	229	276	236
– Gulf of Mexico	14	5	1,051	627	1,065	632
– Alaska	4	1	3	–	7	1
Total United States	27	13	1,321	856	1,348	869
Canada – Onshore, excluding oil sands	36	30	494	446	530	476
– Offshore	89	8	46	3	135	11
– Oil sands – Syncrude	96	5	160	8	256	13
Total Canada	221	43	700	457	921	500
Malaysia	9	8	6,687	4,211	6,696	4,219
United Kingdom	34	4	31	4	65	8
Republic of the Congo	1	–	1,333	902	1,334	902
Suriname	–	–	2,164	1,731	2,164	1,731
Australia	–	–	3,640	1,456	3,640	1,456
Indonesia	–	–	3,301	2,432	3,301	2,432
Brunei	–	–	2,936	519	2,936	519
Kurdistan (Iraq)	–	–	153	76	153	76
Spain	–	–	36	6	36	6
Totals	292	68	22,302	12,650	22,594	12,718

Certain acreage held by the Company will expire in the next three years. Scheduled expirations in 2011 include 401 thousand net acres in Block AC/P36, Australia; 279 thousand acres in South Barito and 75 thousand net acres in Semai II in Indonesia; 346 thousand net acres in Block 37 Suriname; 563 thousand net acres in Block K Malaysia; 356 thousand net acres in Block H Malaysia; and 448 thousand net acres in Blocks MPS and MPN in Republic of the Congo. In 2012, 82 thousand net acres expire in Blocks SK 309 and SK 311 Malaysia; 36 thousand net acres expire in Block PM 311 in Malaysia; and 182 thousand net acres expire in the United States. In 2013, 841 thousand net acres expire in Block H Malaysia; 627 thousand net acres expire in Block P Malaysia; and 161 thousand net acres expire in the United States.

As used in the three tables that follow, "gross" wells are the total wells in which all or part of the working interest is owned by Murphy, and "net" wells are the total of the Company's fractional working interests in gross wells expressed as the equivalent number of wholly owned wells.

The following table shows the number of oil and gas wells producing or capable of producing at December 31, 2010.

	Oil Wells		Gas Wells	
Country	Gross	Net	Gross	Net
United States	46	15	18	10
Canada	313	216	104	104
Malaysia	32	26	20	17
United Kingdom	36	3	23	2
Republic of the Congo	6	3	–	–
Totals	433	263	165	133

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
2010												
Exploratory	**9.2**	**–**	**–**	**–**	**6.8**	**0.8**	**–**	**0.1**	**1.0**	**2.5**	**17.0**	**3.4**
Development	**–**	**–**	**87.0**	**5.0**	**23.6**	**–**	**–**	**–**	**2.5**	**–**	**113.1**	**5.0**
2009												
Exploratory	1.3	0.6	–	–	5.6	1.6	–	–	0.5	0.7	7.4	2.9
Development	1.1	–	42.0	3.0	17.0	–	0.4	–	0.5	–	61.0	3.0
2008												
Exploratory	1.7	1.5	–	–	0.8	4.6	0.2	–	–	–	2.7	6.1
Development	0.8	–	64.4	1.0	9.9	–	0.2	0.1	0.4	–	75.7	1.1

Murphy's drilling wells in progress at December 31, 2010 are shown below.

	Exploratory		Development		Total	
Country	Gross	Net	Gross	Net	Gross	Net
United States	6.0	4.2	–	–	6.0	4.2
Canada	–	–	5.0	4.5	5.0	4.5
Malaysia	1.0	.9	1.0	.8	2.0	1.7
Republic of the Congo	–	–	1.0	.5	1.0	.5
Indonesia	1.0	.3	–	–	1.0	.3
Totals	8.0	5.4	7.0	5.8	15.0	11.2

Refining and Marketing

The Company's refining and marketing businesses are located in the United States and the United Kingdom, and primarily consist of operations that refine crude oil and other feedstocks into petroleum products such as gasoline and distillates, buy and sell crude oil and refined products, and transport and market petroleum products. The Company has announced its intention to sell its U.S. refineries and U.K. refining and marketing operations in 2011. The Company acquired an ethanol production facility in North Dakota during 2009, and also purchased an unfinished ethanol production facility in Texas in 2010.

Murphy Oil USA, Inc. (MOUSA), a wholly owned subsidiary of Murphy Oil Corporation, owns and operates two refineries in the United States. The larger of its U.S. refineries is at Meraux, Louisiana, on the Mississippi River approximately 10 miles southeast of New Orleans. The Company owns a smaller refinery at Superior, Wisconsin. Both U.S. refineries are located on fee land. Murco Petroleum Limited (Murco), a wholly owned U.K. subsidiary, owns 100% interest in a refinery at Milford Haven, Wales, which is primarily located on fee land. Murco acquired the remaining 70% of the Milford Haven refinery that it did not already own on December 1, 2007.

Refinery capacities at December 31, 2010 are shown in the following table.

	Meraux, Louisiana	Superior, Wisconsin	Milford Haven, Wales	Total
Crude capacity – b/sd*	125,000	35,000	135,000	295,000
Process capacity – b/sd*				
Vacuum distillation	50,000	20,500	55,000	125,500
Catalytic cracking – fresh feed	37,000	11,000	37,000	85,000
Naphtha hydrotreating	35,000	11,000	18,300	64,300
Catalytic reforming	32,000	8,000	18,300	58,300
Gasoline hydrotreating	–	7,500	–	7,500
Distillate hydrotreating	52,000	11,200	74,000	137,200
Hydrocracking	32,000	–	–	32,000
Gas oil hydrotreating	12,000	–	–	12,000
Solvent deasphalting	18,000	–	–	18,000
Isomerization	–	–	11,300	11,300
Production capacity – b/sd*				
Alkylation	8,500	1,600	6,300	16,400
Asphalt	–	7,500	–	7,500
Crude oil and product storage capacity – barrels	3,446,000	3,114,000	8,908,000	15,468,000

*Barrels per stream day.

In 2003, Murphy expanded the refinery at Meraux, Louisiana. The expansion included a new hydrocracker unit; an increase of the crude oil processing capacity to 125,000 barrels per stream day (b/sd); an increase to the naphtha hydrotreating capacity to 35,000 b/sd; an increase to the catalytic reforming capacity to 32,000 b/sd; construction of a new sulfur recovery complex, with amine regeneration, sour water stripping and high efficiency sulfur recovery; a new central control room; and two new utility boilers. In 2010, a new laboratory was completed and various units were debottlenecked at Meraux. The Meraux refinery underwent a full plant turnaround in early 2010. At the Superior, Wisconsin, refinery, the Company completed the addition of a fluid catalytic cracking gasoline hydrotreater unit in 2004. In 2006, the isomerization unit at the Superior refinery was converted to a hydrotreater and one of two existing naptha hydrotreaters was converted to a kerosine hydrotreater. In 2010, Superior completed an ultra-low sulfur diesel revamp on its distillate hydrotreaters, which expanded capability of distillate production. Both U.S. refineries are capable of meeting mandatory low-sulfur gasoline and distillate products specifications.

In late August 2005, the Meraux refinery and associated assets were severely damaged by flooding and high winds caused by Hurricane Katrina. The majority of costs to repair the Meraux refinery were covered by insurance. The Company recorded expenses for repair costs not expected to be recoverable from insurance of $50.7 million in 2006 and a further $3.0 million in 2007. The final insurance settlement related to the property damages and repairs was completed in 2009 and income of $12.7 million was recorded in 2009 associated with actual insurance recoveries that exceeded amounts estimated in prior years to be recoverable.

MOUSA markets refined products through a network of retail gasoline stations and branded and unbranded wholesale customers in a 26-state area, primarily in the Southern and Midwestern United States. Murphy's retail stations are located in 22 states and are primarily located in the parking lots of Walmart Supercenters using the brand name Murphy USA®. The Company's stations also include stand-alone locations using the Murphy Express® brand. Branded wholesale customers use the brand name SPUR®. At December 31, 2010, the Company marketed products through 1,099 Murphy owned and operated stations and 116 branded wholesale SPUR stations. Of the Company stations, 1,001 are located on parking lots of Walmart Supercenters and 98 are stand-alone Murphy Express locations. MOUSA plans to build additional retail gasoline stations at Walmart Supercenters and other stand-alone locations in 2011 and beyond. Refined products are supplied from 12 terminals that are wholly owned and operated by MOUSA, two terminals that are leased by Murphy and numerous terminals owned by others. Three of the wholly owned terminals are supplied by marine transportation, three are supplied by truck, four are supplied by pipeline and two are adjacent to MOUSA's refineries. MOUSA also receives products at terminals owned by others either in exchange for deliveries from the Company's terminals or by outright purchase. Six owned terminals and the rights to use two leased terminals are included as a component of the refinery assets held for sale in the U.S.

The Company owns land underlying 873 of the stations on Walmart parking lots. No rent is payable to Walmart for the owned locations. For the remaining gasoline stations located on Walmart property that are not owned, Murphy has master agreements that allow the Company to rent land from Walmart. The master agreements contain general terms applicable to all rental sites in the United States. The terms of the agreements range from 10-15 years at each station, with Murphy holding two successive five-year extension options at each site. The agreements permit Walmart to terminate the agreements in their entirety, or only as to affected sites, at its option for the following reasons: Murphy vacates or abandons the property; Murphy improperly transfers the rights under this agreement to another party; an agreement or a premises is taken upon execution or by process of law; Murphy files a petition in bankruptcy or becomes insolvent; Murphy fails to pay its debts as they become due; Murphy fails to pay rent or other sums required to be paid within 90 days after written notice; or Murphy fails to perform in any material way as required by the agreements. Sales from the Company's U.S. retail marketing stations represented 45.9% of consolidated Company revenues in 2010, 45.7% in 2009 and 42.7% in 2008. As the Company continues to expand the number of retail operated gasoline stations, total revenue generated by this business is expected to grow.

In October 2009, MOUSA acquired an ethanol production facility located in Hankinson, North Dakota. The $92 million purchase price was primarily financed by $82 million of seller-provided nonrecourse debt. The Company chose in 2010 to pay off the nonrecourse debt early. The facility is designed to produce 110 million gallons of corn-based ethanol per year. Ethanol production in 2010, the first full year of operation, totaled more than 115 million gallons at Hankinson. The Company acquired a partially constructed ethanol production facility in Hereford, Texas, in late 2010. The Company paid $40 million for the facility at purchase and expects to spend approximately $25 million to complete construction of the facility. The facility is designed with production capacity of 105 million gallons of corn-based ethanol per year, and it is expected to be in operation near the end of the first quarter of 2011.

Murphy owns a 20% interest in a 120-mile refined products pipeline, with a capacity of 165,000 barrels per day, that transports products from the Meraux refinery to two common carrier pipelines serving the southeastern United States. The Company also owns a 3.2% interest in the Louisiana Offshore Oil Port LLC (LOOP), which provides deepwater unloading accommodations off the Louisiana coast for oil tankers and onshore facilities for storage of crude oil. A crude oil pipeline with a diameter of 24 inches connects LOOP storage at Clovelly, Louisiana, to the Meraux refinery. Murphy owns a 40.1% interest in the first 22 miles of this pipeline from Clovelly to Alliance, Louisiana, and 100% of the remaining 24 miles from Alliance to Meraux.

The Milford Haven, Wales, refinery was shut down for a plant-wide turnaround in early 2010. During the downtime, the Company completed an expansion project that increased the plant's crude oil throughput capacity from 108,000 barrels per day to 135,000 barrels per day.

At the end of 2010, Murco distributed refined products in the United Kingdom from the wholly-owned Milford Haven refinery, three wholly owned terminals supplied by rail, six terminals owned by others where products are received in exchange for deliveries from the Company's terminals and eight terminals owned by others where products are purchased for delivery. At December 31, 2010, there were 234 Company stations, 209 of which were branded MURCO with the remainder under various third party brands. The Company owns the freehold under 151 of the sites and leases the remainder. The Company supplies 217 MURCO branded dealer stations.

In 2010, Murphy owned approximately 1.0% of the crude oil refining capacity in the United States and 7.5% of the refining capacity in the United Kingdom. The Company's market share of U.S. retail gasoline sales was approximately 2.7% in 2010 and in the U.K. Murphy's fuel sales represented 2.1% of the total market share.

A statistical summary of key operating and financial indicators for each of the seven years ended December 31, 2010 are reported on page 6 of the 2010 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 28 through 31.

Web site Access to SEC Reports

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

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

Item 1A. RISK FACTORS

Murphy Oil's businesses operate in highly competitive environments, which could adversely affect it in many ways, including its profitability, its ability to grow, and its ability to manage its businesses.
Murphy operates in the oil and gas industry and experiences intense competition from other oil and gas companies, which include state-owned foreign oil companies, major integrated oil companies, independent producers of oil and natural gas and independent refining and marketing companies. Virtually all of the state-owned and major integrated oil companies and many of the independent producers and refiners that compete with the Company have substantially greater resources than Murphy. In addition, the oil industry as a whole competes with other industries in supplying energy requirements around the world. Murphy competes, among other things, for valuable acreage positions, exploration licenses, drilling equipment and human resources.

If Murphy cannot replace its oil and natural gas reserves, it will not be able to sustain or grow its business.
Murphy continually depletes its oil and natural gas reserves as production occurs. In order to sustain and grow its business, the Company must successfully replace the crude oil and natural gas it produces with additional reserves. Therefore, it must create and maintain a portfolio of good prospects for future reserve additions and production by obtaining rights to explore for, develop and produce hydrocarbons in promising areas. In addition, it must find, develop and produce and/or purchase reserves at a competitive cost structure to be successful in the long-term. Murphy's ability to operate profitably in the exploration and production segments of its business, therefore, is dependent on its ability to find, develop and produce and/or purchase oil and natural gas reserves at costs that are less than the realized sales price for these products and at costs competitive with competing companies in the industry.

Murphy's proved reserves are based on the professional judgment of its engineers and may be subject to revision.
Proved oil and natural gas reserves included in this report on pages F-38 and F-39 have been prepared by Company personnel based on an unweighted average of oil and natural gas prices in effect at the beginning of each month in 2010 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 Securities and Exchange Commission rules, reported proved reserves must be reasonably certain of recovery in future periods.

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

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

The Company's proved undeveloped reserves represent significant portions of total proved reserves. As of December 31, 2010, approximately 19% of the Company's proved oil reserves and 34% 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 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.

The volatility in the global prices of oil, natural gas and petroleum products significantly affects the Company's operating results.
The most significant variables affecting the Company's results of operations are the sales prices for crude oil, natural gas and refined products that it produces. West Texas Intermediate (WTI) crude oil prices averaged about $80 per barrel in 2010, $62 per barrel in 2009 and $99 per barrel in 2008. The Company had overall record net income in 2008 due to high oil sales prices. Earnings for the exploration and production business declined in 2009 from the prior year due to lower oil prices, and then rose in 2010 with higher oil prices compared to 2009. The Company's net income is also significantly affected by changes in the sales price of natural gas and margins on refining and marketing operations. The Company cannot predict how changes in the sales prices of oil and natural gas and changes in refining and marketing margins will affect its

results of operations in future periods. Except in limited cases, the Company typically does not seek to hedge any significant portion of its exposure to the effects of changing prices of crude oil, natural gas and refined products. Certain of the Company's crude oil production is heavy and more sour than WTI quality crude; therefore, this crude oil usually sells at a discount to WTI and other light and sweet crude oils. In addition, the sales prices for heavy and sour crude oils do not always move in relation to price changes for WTI and lighter/sweeter crude oils.

The results of exploration drilling 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 2010, significant wildcat wells were primarily drilled offshore Malaysia, Republic of the Congo and Suriname. The Company's 2011 budget calls for wildcat drilling primarily onshore in Western Canada and Kurdistan, and in waters offshore Brunei, Republic of the Congo, Suriname and Indonesia.

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 expires in June 2012. Although not considered likely, there is the possibility that financing arrangements may not always be available at sufficient levels required to fund the Company's activities in future periods. The Company has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities through September 2012. Outstanding notes of $350 million mature in April 2012. Although not considered likely, the Company may not be able in the future to sell notes at reasonable rates in the marketplace.

Murphy has limited or virtually no control over several factors that could adversely affect the Company.
The ability of the Company to successfully manage development and operating costs is important because virtually all of the products it sells are energy commodities such as crude oil, natural gas and refined products, for which the Company has little or no influence on the sales prices or regional and worldwide consumer demand for these products. An economic slowdown in late 2008 and 2009 had a detrimental effect on the worldwide demand for these energy commodities, which effectively led to reduced prices for oil, natural gas and refined products. Lower prices for crude oil and natural gas inevitably led to lower earnings in the Company's exploration and production operations. Murphy is a net purchaser of crude oil and other refinery feedstocks, and also purchases refined products, particularly gasoline, needed to supply its 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. During 2010, approximately 20% of the Company's total production was at fields operated by others, while at December 31, 2010, approximately 42% of the Company's total proved reserves were at fields operated by others. Therefore, Murphy does not fully control all activities at certain of its significant revenue generating properties.

The operations and earnings of Murphy 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, 2010, approximately 40% 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 tax changes, royalty increases and regulations concerning: currency fluctuations, protection and remediation of the environment (See the caption "Environmental Matters" beginning on page 28 of this Form 10-K report for additional discussion of this risk), preferential and discriminatory awarding of oil and gas leases, restrictions on drilling and/or production, restraints and controls on imports and exports, safety, and relationships between employers and employees. Because these and other factors too numerous to list are subject to changes caused by governmental and political considerations and are often made in response to changing internal and worldwide economic conditions and to actions of other governments or specific events, it is not practical to attempt to predict the effects of such factors on Murphy's future operations and earnings.

Murphy's business is subject to operational hazards and risks normally associated with the exploration for and production of oil and natural gas and the refining and marketing of crude oil and petroleum products.
The Company operates in urban and remote, and often inhospitable, areas around the world. The occurrence of an event, including but not limited to acts of nature such as hurricanes, floods, earthquakes and other forms of severe weather, and mechanical equipment failures,

industrial accidents, fires, explosions, acts of war and intentional terrorist attacks could result in the loss of hydrocarbons and associated revenues, environmental pollution or contamination, and personal injury, including death, for which the Company could be deemed to be liable, and which could subject the Company to substantial fines and/or claims for punitive damages.

In April 2010, a drilling accident and subsequent oil spill occurred in the Gulf of Mexico at the Macondo well owned by other companies. In May 2010, the U.S. President placed a temporary moratorium on new drilling in the Gulf of Mexico that forced the Company to defer planned exploration drilling in the Gulf of Mexico, and to renegotiate a drilling contract to move a deepwater drilling rig to Republic of the Congo. Further impacts of the accident and oil spill include added delays in deepwater Gulf of Mexico drilling activities, and additional future regulations covering offshore drilling operations, plus expected higher costs for future drilling operations and offshore insurance. The 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 of oil and natural gas production 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. Additionally, the Company's largest refinery is located about 10 miles southeast of New Orleans, Louisiana. In August 2005, Hurricane Katrina passed near the refinery causing major flooding and significant wind damage. The gradual loss of coastal wetlands in southeast Louisiana increases the risk of future flooding should storms such as Katrina recur. Other assets such as gasoline terminals and certain retail gasoline stations also lie near the Gulf of Mexico coastlines and are vulnerable to storm damages. During the repairs at Meraux following Hurricane Katrina, the refinery took steps to try to reduce the potential for damages from future storms of similar magnitude. For example, certain key equipment such as motors and pumps were raised above ground level when feasible. These steps may somewhat reduce the damages associated with high winds and flooding that could occur with a future storm similar in strength to Katrina, but the risks from such a storm are not eliminated. Although the Company also maintains insurance for such risks as described below, due to policy deductibles and possible coverage limits, weather-related risks are not fully insured.

There can be no assurance that Murphy's insurance will be adequate to offset costs associated with certain events or 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 $775 million per occurrence and in the annual aggregate. These policies have up to $10 million in deductibles. Generally, this insurance covers various types of claims including those related to personal injury, death, property damage, loss of use and cleanup of hazardous materials discharged into the environment due to a "sudden and accidental" event. The Company also maintains insurance coverage with an additional limit of $250 million per occurrence ($600 million for Gulf of Mexico operations not related to a named windstorm), all or part of which could be applicable to certain sudden and accidental pollution events. The occurrence of an event that is not insured or not fully insured could have a material adverse effect on the Company's financial condition and results of operations in the future. During 2005, damages from hurricanes caused a temporary shut-down of certain U.S. oil and gas production operations as well as the Meraux, Louisiana, refinery. The Company repaired the Meraux refinery and it restarted operations in mid-2006, but the Company did not fully recover repair costs incurred at Meraux under its insurance policies. Damages incurred by the Company from 2008 hurricanes did not exceed deductible limits under the insurance policies. See Notes P and R in the consolidated financial statements for further discussion.

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

The Company is involved in numerous lawsuits seeking cash settlements for alleged personal injuries, property damages and other business-related matters. The most significant of these matters are addressed in more detail in Item 3 on page 15 of this Form 10-K report.

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

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

The 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 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, 2010.

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-36 to F-44 and in Note E—Property, Plant and Equipment beginning on page F-13.

Executive Officers of the Registrant

The age at January 1, 2011, present corporate office and length of service in office of each of the Company's executive officers are reported in the following listing. Executive officers are elected annually but may be removed from office at any time by the Board of Directors.

David M. Wood – Age 53; President and Chief Executive Officer and Director and Member of the Executive Committee since January 2009. Mr. Wood served as Executive Vice President responsible for the Company's worldwide exploration and production operations from January 2007 through December 2008, President of Murphy Exploration & Production Company-International from March 2003 through December 2006 and Senior Vice President of Frontier Exploration & Production from April 1999 through February 2003.

Steven A. Cossé – Age 63; Executive Vice President since February 2005 and General Counsel since August 1991. Mr. Cossé was elected Senior Vice President in 1994 and Vice President in 1993. Mr. Cossé has announced his retirement as of March 1, 2011.

Roger W. Jenkins – Age 49; Executive Vice President Exploration and Production since August 2009. Mr. Jenkins has served as President of the Company's exploration and production subsidiary since January 2009. He was Senior Vice President, North America for this subsidiary from September 2007 to December 2008, and prior to that time, held various positions, including General Manager of the Company's exploration and production operations in Sabah, Malaysia.

Thomas McKinlay – Age 47; Executive Vice President, World Wide Downstream Operations since January 2011. Mr. McKinlay was Vice President, U.S. Manufacturing from August 2009 to January 2011. Mr. McKinlay also became President of the Company's U.S. refining and marketing subsidiary effective January 2011 and was Vice President, Supply and Transportation of this subsidiary from April 2009 to January 2011. From August 2008 to March 2009, Mr. McKinlay was General Manager, Supply and Transportation of this U.S. subsidiary, and from January 2007 to August 2008 was Supply Director for the Company's U.K. refining and marketing subsidiary.

Kevin G. Fitzgerald – Age 55; Senior Vice President and Chief Financial Officer since January 1, 2007. He served as Treasurer from July 2001 through December 2006 and was Director of Investor Relations from 1996 through June 2001.

Bill H. Stobaugh – Age 59; Senior Vice President since February 2005. Mr. Stobaugh joined the Company as Vice President in 1995.

Mindy K. West – Age 41; Vice President and Treasurer since January 1, 2007. Ms. West was Director of Investor Relations from July 2001 through December 2006.

John W. Eckart – Age 52; Vice President and Controller since January 1, 2007. Mr. Eckart served as Controller since March 2000.

Kelli M. Hammock – Age 39; Vice President, Administration since December 2009. Ms. Hammock was General Manager, Administration from June 2006 to November 2009.

Walter K. Compton – Age 48; Vice President, Law since February 2009 and Secretary since December 1996. Effective March 1, 2011, Mr. Compton will be promoted to Senior Vice President and General Counsel, replacing Mr. Cossé who will retire on that date.

John A. Moore – Age 43; Secretary effective March 1, 2011. Mr. Moore was Senior Attorney from 2005 to February 2011.

Item 3. LEGAL PROCEEDINGS

Litigation arising out of a June 10, 2003 fire in the Residual Oil Supercritical Extraction (ROSE) unit at the Company's Meraux, Louisiana refinery was settled in July 2009 and memorialized via a filing in the U.S. District Court for the Eastern District of Louisiana on July 24, 2009. An arbitral tribunal heard the Company's claim for indemnity from one of its insurers, AEGIS, in September 2009 and a decision is pending. The Company believes that insurance coverage does apply for this matter. The Company continues to believe that the ultimate resolution of the June 2003 ROSE fire litigation, including associated insurance coverage issues, will not have a material adverse effect on its net income, financial condition or liquidity in a future period.

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.

PART II

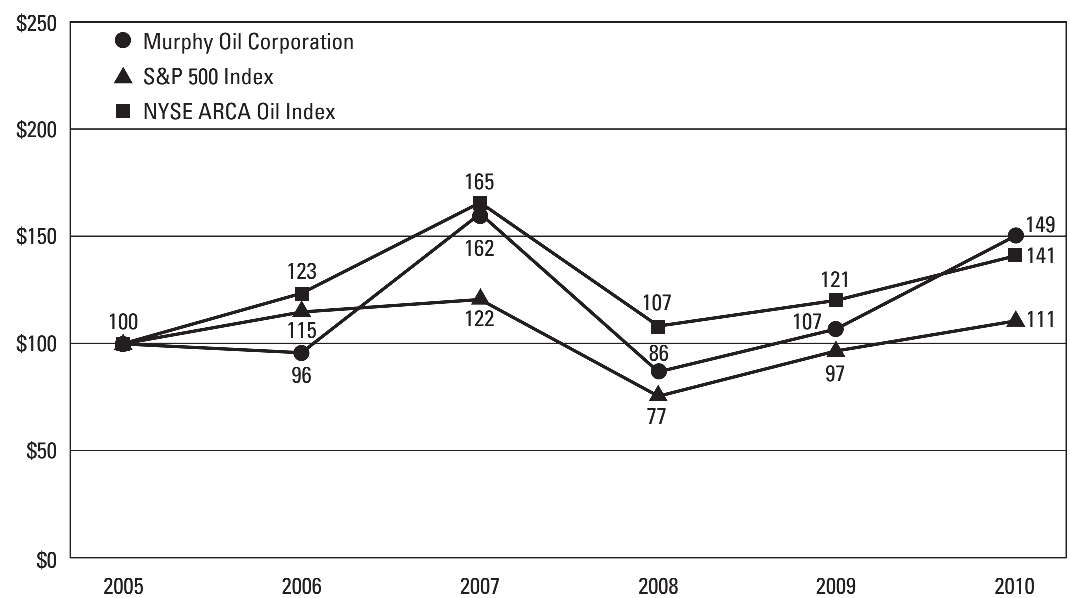
Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The Company's Common Stock is traded on the New York Stock Exchange using "MUR" as the trading symbol. There were 2,363 stockholders of record as of December 31, 2010. Information as to high and low market prices per share and dividends per share by quarter for 2010 and 2009 are reported on page F-45 of this Form 10-K report.

SHAREHOLDER RETURN PERFORMANCE PRESENTATION

The following graph presents a comparison of cumulative five-year shareholder returns (including the reinvestment of dividends) as if a $100 investment was made on December 31, 2005 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.

Murphy Oil Corporation
Comparison of Five-Year Cumulative Shareholder Returns
SOURCE: Bloomberg L.P.



	2005	2006	2007	2008	2009	2010
Murphy Oil Corporation	100	96	162	86	107	149
S&P 500 Index	100	115	122	77	97	111
NYSE ARCA Oil Index	100	123	165	107	121	141

Item 6. SELECTED FINANCIAL DATA

(Thousands of dollars except per share data)	**2010**	2009	2008	2007	2006
Results of Operations for the Year					
Sales and other operating revenues	**$23,401,117**	18,918,181	27,360,625	18,297,637	14,156,666
Net cash provided by continuing operations	**3,128,558**	1,865,647	2,924,436	1,673,503	906,561
Income from continuing operations	**798,081**	740,517	1,744,749	739,080	603,050
Net income	**798,081**	837,621	1,739,986	766,529	644,669
Per Common share – diluted					
Income from continuing operations	**$ 4.13**	3.85	9.08	3.87	3.19
Net income	**4.13**	4.35	9.06	4.01	3.41
Cash dividends per Common share	**1.05**	1.00	.875	.675	.525
Percentage return on[1]					
Average stockholders' equity	**10.3**	12.5	29.1	16.8	16.8
Average borrowed and invested capital	**9.4**	10.9	24.4	13.9	14.4
Average total assets	**5.9**	7.0	15.1	8.5	9.3
Capital Expenditures for the Year[2]					
Continuing operations					
Exploration and production	**$ 2,034,828**	1,807,561	1,928,346	1,740,327	1,046,463
Refining and marketing	**407,413**	375,897	426,156	572,458	173,400
Corporate and other	**5,899**	22,967	3,235	4,146	6,383
	2,448,140	2,206,425	2,357,737	2,316,931	1,226,246
Discontinued operations	**–**	844	6,949	40,416	36,293
	$ 2,448,140	2,207,269	2,364,686	2,357,347	1,262,539
Financial Condition at December 31					
Current ratio	**1.21**	1.55	1.51	1.37	1.61
Working capital	**$ 619,783**	1,194,087	958,818	777,530	795,986
Net property, plant and equipment	**10,367,847**	9,065,088	7,727,718	7,109,822	5,106,282
Total assets	**14,233,243**	12,756,359	11,149,098	10,535,849	7,483,161
Long-term debt	**939,350**	1,353,183	1,026,222	1,516,156	840,275
Stockholders' equity	**8,199,550**	7,346,026	6,278,945	5,066,174	4,121,273
Per share	**42.52**	38.44	32.92	26.70	21.97
Long-term debt – percent of capital employed	**10.3**	15.6	14.0	23.0	16.9

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

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

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

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

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

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 refining and marketing operations in the United States and 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 primarily by selling oil and natural gas production and refined petroleum products to customers at hundreds of locations in the United States, Canada, Malaysia, the United Kingdom and other countries. 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 refinery feedstocks, natural gas is purchased for fuel at its refineries and 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.

Worldwide oil and North American natural gas prices were higher in 2010 than in 2009, but these prices were significantly lower on average in 2009 than in 2008. The sales price for a barrel of West Texas Intermediate crude oil averaged $79.61 in 2010, $62.05 in 2009 and $98.90 in 2008. The NYMEX natural gas price per million British Thermal Units (MMBTU) averaged $4.38 in 2010, $3.94 in 2009 and $8.89 in 2008. Crude oil prices generally strengthened in 2010 as the worldwide economy began to show signs of recovery following the deep recession that began in 2008. WTI oil prices in 2010 averaged 28% higher than 2009. The year 2009 began with quite low demand for hydrocarbons and consequently very weak prices for oil and natural gas. Crude oil and natural gas prices rose as 2009 progressed as the slow economic recovery began. Crude oil and North American natural gas prices fell precipitously with the economic decline in late 2008. 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 68% of the total hydrocarbons produced on an energy equivalent basis (one barrel of oil equals six thousand cubic feet of natural gas) by the Company in 2010. In 2011, the percentage of hydrocarbon production represented by oil is expected to decline to about 61% due to start-up of significant natural gas production in the first quarter 2011 at the Tupper West area in British Columbia. If the prices for crude oil and natural gas should weaken in 2010 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.

Results of Operations

Murphy had net income in 2010 of $798.1 million ($4.13 per diluted share) compared to net income of $837.6 million ($4.35 per diluted share) in 2009. The prior year included income from discontinued operations in Ecuador of $97.1 million ($0.50 per diluted share). Income from discontinued operations in 2009 primarily arose from a gain on disposal of all Ecuador assets in March 2009. Excluding Ecuador, income from continuing operations was $798.1 million ($4.13 per diluted share) in 2010 and $740.5 million ($3.85 per diluted share) in 2009. Income in 2010 rose for both the exploration and production (E&P) and refining and marketing (R&M) operations compared to the prior year. Earnings for the Company's E&P operations increased in 2010 primarily due to higher sales prices and sales volumes of crude oil and natural gas. The Company's R&M earnings were higher in 2010 primarily due to stronger margins on U.S. retail gasoline fuel sales. Earnings in 2010 were unfavorably affected compared to 2009 by higher net costs associated with Corporate activities that were not allocated to operating segments, with the higher costs primarily caused by an unfavorable variance for the effects of transactions denominated in foreign currencies.

Net income in 2009 of $837.6 million ($4.35 per diluted share) was well below net income in 2008 of $1.74 billion ($9.06 per diluted share). The large decline in 2009 net income in comparison to 2008 was attributable to lower earnings in both the E&P and R&M operations. Weaker oil and natural gas sales prices in 2009 were the primary reasons for lower earnings in the E&P business, while lower retail gasoline margins in the U.S. and weaker refining margins in the U.K. led to the earnings decline for R&M. The net cost of corporate activities not allocated to the operating segments was lower in 2009 than in 2008. Income from continuing operations, excluding results from Ecuador operations which are reported as discontinued operations, was $740.5 million ($3.85 per diluted share) in 2009 compared to $1.74 billion ($9.08 per diluted share) in 2008.

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

2010 vs. 2009 – Net income in 2010 was $798.1 million ($4.13 per diluted share) compared to $837.6 million ($4.35 per diluted share) in 2009. The 2009 results included income from discontinued operations of $97.1 million ($0.50 per diluted share). The discontinued operations income was associated with Ecuador properties sold in March 2009 and primarily arose from an after-tax gain on disposal of $103.6 million. Income from continuing operations in 2010 and 2009 were $798.1 million ($4.13 per diluted share) and $740.5 million ($3.85 per diluted share), respectively. The higher 2010 income from continuing operations compared to 2009 was caused by higher earnings in both the exploration and production (E&P) and refining and marketing (R&M) businesses, but these were partially offset by higher net costs for unallocated corporate activities.

E&P income from continuing operations improved $115.1 million in 2010, primarily due to a $10.70 per barrel higher realized sales price for crude oil in the most recent year. The 2009 results were impacted by two unusual items. First, an after-tax gain of $158.3 million in 2009 was derived from a recovery of certain deepwater Gulf of Mexico federal royalties paid in prior years. Second, an after-tax charge of $58.4 million was recorded in 2009 associated with a required one-time working interest redetermination at the Terra Nova field, offshore Eastern Canada. The 2010 E&P results were also favorably affected, but in less significant measures, by higher sales volumes for crude oil and natural gas and higher sales prices for natural gas. E&P was unfavorably affected in 2010 compared to the prior year by higher expenses for exploration, production, depreciation and administration. Income from R&M operations was $77.4 million more in 2010, with the improvement mostly attributable to slightly more than a $0.03 per gallon improvement in margins on sale of gasoline at U.S. retail marketing stations. This was partially offset by higher net losses in 2010 for U.K. R&M operations. The net costs of corporate activities were higher by $134.9 million in 2010, mostly attributable to unfavorable effects of transactions denominated in foreign currencies. To a lesser degree, the 2010 corporate net costs were unfavorably affected by lower interest income and higher expenses for interest and administration. The unfavorable variance in foreign currency transactions in 2010 was primarily attributable to a strengthening of the Malaysian ringgit versus the U.S. dollar and weakening of the British pound sterling against the U.S. dollar during the year.

Sales and other operating revenues grew $4.5 billion in 2010 compared to 2009 mostly due to higher sales prices for gasoline and other motor fuels in the current year. Additionally, higher sales prices and sales volumes for crude oil and natural gas in the E&P segment contributed to the increase in 2010 revenue. Gain on sale of assets was $2.8 million less in 2010 than 2009 because the prior year included a $3.9 million gain on sale of a small Canadian natural gas field. Interest and other operating income (loss) declined by $147.4 million in 2010 compared to 2009 mostly due to a $114.3 million unfavorable variance from the effects of transactions denominated in foreign currencies, plus nonrecurring interest income in 2009 of $42.0 million associated with a recovery of Federal royalties paid in prior years for production at certain deepwater Gulf of Mexico fields. The expense associated with crude oil and product purchases increased by $3.6 billion in 2010 compared to 2009 due to higher average costs in the current year for crude oil feedstocks at the Company's three refineries and due to the higher costs of 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 $345.4 million higher in 2010 than 2009 due to a combination of higher oil and natural gas production costs, higher operating costs associated with the three oil refineries, and higher costs for U.S. retail gasoline station operations. Exploration expenses rose $27.1 million in 2010 compared to 2009 due to higher geophysical costs in the Gulf of Mexico and Republic of the Congo, higher amortization expense for undeveloped leases in the Eagle Ford Shale, and higher administrative office and study costs in foreign locations. Exploration costs in 2010 included lower dry hole costs in Malaysia, Australia and the U.S., which more than offset higher dry hole costs in Republic of the Congo, Suriname and the U.K. Selling and general expenses were $36.9 million higher in 2010 compared to the prior year primarily due to higher employee compensation costs. Depreciation, depletion and amortization expense rose $245.7 million in 2010 versus 2009 due to higher natural gas and crude oil sales volumes in 2010, higher E&P per-unit depreciation rates, and higher R&M depreciation that included a new ethanol production facility, more U.S. retail gasoline stations and the crude unit expansion at the Milford Haven, Wales, refinery that was completed in 2010. Impairment of properties was nil in 2010 and $5.2 million in 2009, with the prior year costs related to write-off of an underperforming natural gas field in the Gulf of Mexico. Accretion of asset retirement obligations was $5.7 million more in 2010 than 2009 primarily due to higher discounted abandonment liabilities in the current year for wells drilled in Malaysia and for synthetic oil operations at Syncrude. Expense for redetermination of working interest at the Terra Nova field was $64.9 million less in 2010 than 2009 because the prior year included cumulative costs for the period of December 2004 through 2009, while 2010 costs related only to current year volumes sold by the Company prior to the effective date of the final settlement. Interest expense was $0.2 million higher in 2010 primarily due to nine months of interest in the current year on nonrecourse debt associated with the Hankinson, North Dakota, ethanol production facility, compared to three months of interest on this debt in the prior year following the October 1, 2009 acquisition date. The nonrecourse debt was paid off by the Company in September 2010. The higher nonrecourse debt interest was mostly offset by lower interest expense on outstanding general bank financing balances in 2010. Capitalized interest was $10.2 million less in 2010 than in the prior year due to interest amounts allocated to the Sarawak natural gas development in 2009 prior to start-up of operations later that year, partially offset by higher interest allocated to the Tupper West gas development in 2010. Income tax expense in 2010 was $79.5 million more than 2009 due to higher pretax earnings and a slightly higher overall effective tax rate in the current year. The consolidated effective tax rate was 43.6% in 2010 compared to 42.0% in 2009, with the rate increase in the current year caused by a larger percentage of earnings in higher tax jurisdictions in 2010 and due to higher current year exploration and other expenses in foreign jurisdictions where no income tax benefit can presently be recognized due to no assurance that these expenses will be realized in 2010 or future years to reduce taxes owed. The tax rates in both 2010 and 2009 were higher than the U.S. federal statutory tax rate of 35.0% due to a combination of U.S. state income taxes, certain foreign tax rates that exceeded the U.S. federal tax rate, and certain exploration and other expenses in foreign taxing jurisdictions for which no income tax benefit is currently being recognized because of the Company's uncertain ability to obtain tax benefits for these costs in 2010 or future years. Income from discontinued operations was $97.1 million ($0.50 per diluted share) in 2009 mostly due to an after-tax gain of $103.6 million on sale of Ecuador operations in March 2009. There was no income from discontinued operations in 2010.

2009 vs. 2008 – Net income in 2009 totaled $837.6 million ($4.35 per diluted share) compared to $1.74 billion ($9.06 per diluted share) in 2008. Earnings included discontinued operations income of $97.1 million ($0.50 per diluted share) in 2009 compared to a loss of $4.8 million ($0.02 per diluted share) in 2008. Discontinued operations were associated with the Company's former operations in Ecuador which were sold in March 2009 for an after-tax gain of $103.6 million. Income from continuing operations amounted to $740.5 million ($3.85 per diluted share) in 2009, down from $1.74 billion ($9.08 per diluted share) in 2008. The lower earnings in 2009 from continuing operations was attributable to lower income in the exploration and production (E&P) and refining and marketing (R&M) businesses.

E&P income from continuing operations was $911.0 million lower in 2009 compared to 2008, primarily attributable to weaker realized sales prices for crude oil, which were down about $33.00 per barrel for the Company's production. Other unfavorable impacts in 2009 included a $58.4 million charge after taxes to effect an anticipated reduction in the Company's working interest in the Terra Nova oil field offshore Newfoundland, lower North American natural gas sales prices, gains on sale of Canadian assets in 2008 that did not repeat in 2009, and higher extraction costs for oil and gas produced in 2009. E&P results in 2009 benefited from higher volumes of oil and gas produced, lower exploration expenses and after-tax income of $158.3 million from recovery of federal royalties paid between 2003 and 2009 on certain leases in the Gulf of Mexico. Income from R&M operations was $242.1 million lower in 2009 compared to 2008, essentially attributable to two factors – weaker retail gasoline marketing margins in the U.S. and weaker refining margins in the U.K. The net cost of corporate activities was $148.8 million less in 2009 than 2008 primarily due to gains from transactions denominated in foreign currencies in 2009 compared to losses on such transactions in 2008. During 2009 the U.S. dollar generally weakened in comparison to the British pound sterling, which provided a favorable foreign currency impact to the Company's earnings. Additionally, 2009 benefited from higher interest income, including interest due to the Company through December 31, 2009 on the federal royalty refund, and lower net interest expense.

Sales and operating revenues were $8.4 billion less in 2009 than 2008 primarily due to lower prices realized on gasoline and other fuels sold by the Company. Crude oil and natural gas sales prices were also lower in 2009 than 2008. But these lower prices were partially offset by income of $244.4 million in 2009 associated with a recovery of federal royalties previously paid by the Company on certain deepwater Gulf of Mexico properties. Gain on sale of assets classified in continuing operations was $130.0 million less in 2009 than 2008 principally due to significant gains on two assets sold in Canada in 2008 – Berkana Energy and the Lloydminster properties. Interest and other income in 2009 was $152.5 million higher than 2008 due to a combination of more favorable income effects from transactions denominated in foreign currencies and interest income on the recovery of federal royalties. Crude oil and product purchases expense was $7.1 billion less in 2009 than 2008 due mostly to the lower cost of gasoline purchased for resale in the U.S. retail marketing operations. Operating expenses in 2009 were $35.6 million less than 2008 mostly due to lower natural gas and other power costs in 2009 at synthetic oil operations in Canada and at the Company's three refineries. Exploration expense in 2009 was $79.2 million below 2008 primarily due to less spending on geophysical data in the U.S., Canada and Malaysia, and less amortization expense for undeveloped lease costs in the Tupper area in Western Canada. Selling and general expenses rose $13.8 million in 2009 compared to 2008 primarily due to a combination of higher costs for employee compensation and professional services. Depreciation, depletion and amortization expense was up $251.8 million in 2009 mostly due to higher oil and natural gas production volumes and higher depreciation rates per barrel of oil equivalents produced, with the higher costs mostly caused by new fields that came on stream in 2009. Impairment of long-lived assets of $5.2 million in 2009 was attributable to write-off of the remaining net book value for one underperforming natural gas field in the Gulf of Mexico. Accretion of asset retirement obligations increased $1.7 million in 2009 primarily due to future abandonment costs to be incurred on oil and gas wells drilled in Malaysia in 2009. A charge of $83.5 million was recorded in 2009 to reflect the estimated cash settlement to be paid on an anticipated reduction in the Company's working interest in the Terra Nova field from the present 12.0% to about 10.5% retroactive to approximately December 2004. This redetermination process at Terra Nova was essentially completed in 2010. Interest expense in 2009 was $20.6 million less than 2008 primarily due to lower interest rates charged on certain bank loans during 2009. Interest capitalized to oil and gas development projects in 2009 was $2.8 million below the 2008 level due to commencement of production at the Thunder Hawk and Azurite oil fields in the third quarter 2009. Income tax expense was $537.0 million less in 2009 than 2008 primarily due to lower pretax income in 2009. The effective tax rate on a consolidated basis increased from 38.1% in 2008 to 42.0% in 2009 due to a larger percentage of earnings in higher tax jurisdictions in 2009 and due to higher exploration and other expenses in foreign jurisdictions where no income tax benefit can presently be recognized due to no assurance that these expenses would be realized in 2009 or future years to reduce taxes owed. The tax rates in both 2009 and 2008 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 exceed 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 2009 or future years. Income from discontinued operations was $101.9 million higher in 2009 than 2008 mostly due to an after-tax gain of $103.6 million on sale of Ecuador operations in March 2009.

Segment Results – In the following table, the Company's results of operations for the three years ended December 31, 2010, 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)	**2010**	2009	2008
Exploration and production – continuing operations			
United States	**$ 72.7**	178.0	156.6
Canada	**213.8**	64.8	588.7
Malaysia	**659.4**	561.9	865.3
United Kingdom	**30.5**	12.6	73.8
Republic of the Congo	**(77.2)**	(20.6)	(1.1)
Other	**(92.3)**	(104.9)	(80.5)
	806.9	691.8	1,602.8
Refining and marketing			
United States Manufacturing	**28.4**	31.2	(39.8)
United States Marketing	**155.4**	61.0	267.7
United Kingdom	**(34.7)**	(20.5)	85.9
	149.1	71.7	313.8
Corporate and other	**(157.9)**	(23.0)	(171.8)
Income from continuing operations	**798.1**	740.5	1,744.8
Income (loss) from discontinued operations	–	97.1	(4.8)
Net income	**$ 798.1**	837.6	1,740.0

Exploration and Production – Earnings from exploration and production (E&P) continuing operations were $806.9 million in 2010, $691.8 million in 2009 and $1.60 billion in 2008.

Income from E&P continuing operations in 2010 was $115.1 million more than in 2009. The increase was primarily attributable to higher sales prices for crude oil and other liquid hydrocarbons produced by the Company. The Company's average realized sales price for crude oil, condensate and gas liquids in 2010 increased $10.70 per barrel over 2009. The Company's average natural gas sales prices in North American and Sarawak Malaysia were also higher in 2010 than 2009. E&P income in 2009 included a $158.3 million after-tax one-time benefit from recovery of previously paid federal royalties associated with certain fields in the deep waters of the Gulf of Mexico. Although both 2010 and 2009 had charges associated with a redetermination of working interest at the Terra Nova field offshore Eastern Canada, 2009 charges were higher by $64.9 million due to that year including estimated costs to settle the period from December 2004 to 2009, while 2010 included only costs for the current year. The one-time redetermination process was essentially completed in 2010 and reduced the Company's working interest at Terra Nova from the original 12.0% to 10.475%. Earnings in 2010 benefited from higher crude oil and natural sales volumes. Crude oil and liquids sales volumes increased 2% in 2010 while natural gas sales volumes rose 91%. The higher hydrocarbon sales volumes in 2010 led to higher expenses for production and depreciation of $225.0 million and $229.2 million, respectively. The 2010 year also had higher exploration expenses of $27.1 million compared to 2009, essentially due to higher expenses related to geophysical activities, undeveloped lease amortization and administration, which were somewhat offset by lower expenses for dry holes. Crude oil sales volumes increased in 2010 in the U.S. due to a full year of production at the Thunder Hawk field in the Gulf of Mexico; this field started producing in July 2009. Heavy oil sales volumes in Canada were lower in 2010 than 2009 due to lower gross production and a higher royalty rate in the Seal area of Western Canada. Sales volumes in 2010 offshore Canada were below 2009 levels mostly due to lower gross production at the Terra Nova field and a higher royalty rate at the Hibernia field. Synthetic oil sales at Syncrude increased in 2010 due to higher gross production compared to 2009. Sales volumes for crude oil produced in Malaysia were lower in 2010 due to less production at the Kikeh field offshore Sabah. Crude oil liquids sold in the U.K. rose in 2010 due to making up for undersold inventory barrels produced in 2009 at the Schiehallion field. Crude oil sales increased in 2010 in Republic of the Congo due to a full year of production at the Azurite field following production start-up in August 2009. Natural gas sales volumes in 2010 increased significantly compared to the prior year due to a full year of production and higher daily sales volumes at gas fields which started up in 2009 offshore Sarawak Malaysia, as well as higher sales volumes at the Tupper area in Western Canada.

E&P income from continuing operations in 2009 was $911.0 million less than in 2008 primarily due to significantly lower realized sales prices for the Company's crude oil production in 2009. The 2009 period was also unfavorably affected by several other factors, including lower North American natural gas sales prices, higher production and depreciation expenses, a $58.4 million after-tax charge for an anticipated reduction of its working interest in the Terra Nova field, and higher gains on asset sales in 2008 compared to 2009. The 2009 year benefited from higher oil and natural gas sales volumes, lower exploration expense and after-tax income of $158.3 million from recovery of previously paid federal royalties on production from certain deepwater Gulf of Mexico properties. Crude oil, condensate and gas liquids sales volumes from continuing operations were 8% higher in 2009 compared to 2008, compared to an increase in oil production volumes of 18% in 2009. Oil sales volumes did not rise as much as oil production volumes during 2009 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 2009 due to an increase in the volume of unsold barrels at the field at year-end and a higher percentage of such unsold inventory barrels at the field being attributable to the Company's account. During 2008, Kikeh sales volumes exceeded production, which effectively reduced the Company's unsold inventory balance from year-end 2007. Higher U.S. crude oil sales volume in 2009 was primarily attributable to a partial year of production at the Gulf of Mexico Thunder Hawk field, which started up in

July 2009, and less downtime in the Gulf of Mexico for hurricanes. Lower crude oil sales volumes in Canada in 2009 were mostly attributable to the sale of the Lloydminster heavy oil field in early 2008 and production declines at the maturing Hibernia and Terra Nova fields. Lower crude oil sales volume in the U.K. in 2009 was primarily due to no sale at the Schiehallion field during the year, as damage to sales equipment at the production facility caused the scheduled oil sale in December 2009 to be deferred until 2010. Crude oil sales volumes at Kikeh in 2009 rose compared to 2008 due to higher annual production. Natural gas sales volumes increased 237% in 2009 and the improvement was partially attributable to higher gas volumes produced during 2009 in the Gulf of Mexico, the Tupper area in Western Canada and at Kikeh, and partially due to new production at the Sarawak gas fields offshore Malaysia following start-up in September 2009. The Company's realized crude oil sales prices averaged 37% less in 2009 than 2008 and North American natural gas sales prices averaged 63% below 2008 levels.

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-41 and F-42 of this Form 10-K report. Average daily production and sales rates and weighted average sales prices are shown on page 5 of the 2010 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)	**2010**	2009	2008
United States			
Oil and gas liquids	**$ 557.6**	374.8	374.0
Natural gas	**87.0**	80.6	162.1
Canada			
Conventional oil and gas liquids	**388.6**	365.6	775.8
Synthetic oil	**378.6**	288.5	459.6
Natural gas	**132.1**	68.6	5.5
Malaysia			
Oil and gas liquids	**1,531.1**	1,478.4	1,985.6
Natural gas	**307.1**	45.4	0.1
United Kingdom			
Oil and gas liquids	**118.8**	54.7	189.4
Natural gas	**14.1**	6.4	25.8
Republic of the Congo – oil	**156.7**	24.5	–
Total oil and gas revenues	**$3,671.7**	2,787.5	3,977.9

The Company's total crude oil, condensate and natural gas liquids production from continuing operations, which excludes discontinued operations in Ecuador sold in March 2009, averaged 126,927 barrels per day in 2010, 130,522 barrels per day in 2009 and 110,842 barrels per day in 2008.

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

Oil production in the U.S. increased from 10,668 barrels per day in 2008 to 17,053 barrels per day in 2009 with the increase mostly caused by start-up of the Thunder Hawk field in July 2009 and higher production at the Medusa and Front Runner fields in 2009. Production of heavy oil in the Western Canada Sedimentary Basin was 6,813 barrels per day in 2009, down from 8,484 barrels per day in 2008, primarily due to the sale of the Lloydminster property in early 2008 and due to decline at properties operated by a third party in the Seal area. Oil production offshore Canada fell from 16,826 barrels per day in 2008 to 12,357 barrels per day in 2009 due to field decline at Terra Nova and field decline and a higher net profit royalty rate at Hibernia. Synthetic oil operations at Syncrude had net production of 12,855 barrels per day in 2009, up from 12,546 barrels per day in 2008, with the increase caused by a lower royalty rate in 2009 due to sales prices significantly below those of the prior year. Oil production in Malaysia increased from 57,403 barrels per day in 2008 to 76,322 barrels per day in 2009, with the increase primarily due to higher production at the Kikeh field, which recorded peak production levels during 2009. Oil production in Malaysia was also favorably affected in 2009 by condensate produced at the Sarawak gas fields that started up in September 2009 and higher net oil production at the West Patricia field. A higher portion of production at West Patricia was allocated to the Company's account in 2009 as costs incurred for development of Sarawak gas fields increased the level of West Patricia oil used to recover costs under the production sharing contract for

Blocks SK 309 and SK 311. Oil production in the U.K. was 3,361 barrels per day in 2009, down from 4,869 barrels per day in 2008, with the decline primarily due to more downtime at the Schiehallion field, mostly due to a damaged export hose that required production to be shut-in for nearly all of the fourth quarter. The Azurite field offshore Republic of the Congo came on production in August 2009 and averaged 1,743 barrels per day for the full year of 2009. The Company sold its interest in Block 16 and other areas in Ecuador in March 2009 and has accounted for Ecuador as discontinued operations. Oil production in Ecuador, excluded from the totals for continuing operations, averaged 1,317 barrels per day in 2009 and 7,412 barrels per day in 2008.

Worldwide sales of natural gas were 356.8 million cubic feet (MMCF) per day in 2010, 187.3 MMCF per day in 2009 and 55.5 MMCF per day in 2008.

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

Natural gas production in the U.S. averaged 54.2 MMCF per day in 2009, compared to 45.8 MMCF per day in 2008. The higher volume in 2009 was primarily attributable to the Mondo NW field that reached peak production during 2009, start-up of the Thunder Hawk field in July 2009 and less downtime in the Gulf of Mexico due to hurricanes. Natural gas production in Canada rose from 1.9 MMCF per day in 2008 to 54.9 MMCF per day in 2009 due to ramp-up of Tupper area production in Western Canada. Tupper started up in December 2008. Natural gas production in Malaysia also rose significantly in 2009 as the Sarawak gas development started up in September 2009 and Kikeh gas production, which started up in December 2008, was onstream for a full year in 2009. Natural gas production during 2009 at Sarawak and Kikeh averaged 28.1 MMCF per day and 46.6 MMCF per day, respectively. Natural gas production in the U.K. fell from 6.4 MMCF per day in 2008 to 3.5 MMCF per day in 2009 primarily due to the Amethyst field being shut-in for the first four months of 2009 for equipment repairs.

The Company's average worldwide realized sales price for crude oil, condensate and gas liquids from continuing operations was $67.11 per barrel in 2010, $56.41 per barrel in 2009 and $89.16 per barrel in 2008.

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

The decline in the Company's average realized oil sales price of 37% in 2009 compared to 2008 matched the decline in the average price of West Texas Intermediate (WTI) crude oil during 2009. Crude oil prices began to weaken in late 2008 as the economic downturn worsened. Crude oil prices started 2009 at low levels due to a weakening worldwide demand for energy, but improved as the year progressed. Compared to 2008, the Company's average 2009 crude oil sales prices fell 37% in the U.S. to $60.08 per barrel; heavy oil prices in Canada fell 31% to $40.45 per barrel; offshore Canada oil was sold for 40% less and averaged $58.19 per barrel; synthetic crude oil sold for 39% less at $61.49 per barrel; crude oil in Malaysia was down 37% and averaged $55.51 per barrel; and U.K. crude oil production sold for 32% less at $61.31 per barrel.

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

The Company's natural gas sales prices fell significantly in 2009 compared to 2008 as weaker demand for energy led to an oversupply of natural gas inventories. The Company's average realized North American natural gas sales prices were $3.57 per thousand cubic feet (MCF) in 2009, a decline of 63% from the $9.54 per MCF realized in 2008. In the U.K. the average sales price fell from $10.98 per MCF in 2008 to $5.04 per MCF in 2009. Natural gas produced in 2009 offshore Sarawak was sold at an average price of $4.05 per MCF during the year.

Based on 2010 sales volumes and deducting taxes at marginal rates, each $1.00 per barrel and $0.10 per MCF fluctuation in prices would have affected 2010 earnings from exploration and production continuing operations by $30.0 million and $8.4 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 from continuing operations were $879.5 million in 2010, $654.5 million in 2009 and $611.5 million in 2008. These amounts are shown by major operating area on pages F-41 and F-42 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)	**2010**	2009	2008
United States	**$12.46**	10.62	10.01
Canada			
Excluding synthetic oil	**8.45**	9.44	9.44
Synthetic oil	**42.61**	36.64	41.08
Malaysia	**9.31**	8.00	10.31
United Kingdom	**14.46**	17.97	13.21
Republic of the Congo	**31.30**	43.51	–
Worldwide – excluding synthetic oil	**10.51**	9.21	10.24

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

Costs per barrel in the U.S. increased in 2009 compared to 2008 due to start-up of the Thunder Hawk field in July 2009. The per-unit cost for Canadian conventional oil and gas operations was flat in 2009 compared to 2008 as the benefit of a full year of natural gas production at Tupper was offset by lower production volumes without a comparable reduction in costs at Hibernia and Terra Nova. Lower cost per barrel in 2009 compared to 2008 at Canadian synthetic oil operations was mostly caused by lower natural gas fuel costs. Production cost per unit in Malaysia was lower in 2009 compared to 2008 due to higher oil production at Kikeh, and new natural gas production offshore Sarawak and higher natural gas production at Kikeh that collectively altered the production mix toward lower cost natural gas in 2009. Higher per-barrel production expense in the U.K. in 2009 compared to 2008 was primarily attributable to lower production levels at the Schiehallion and Amethyst fields, both of which were offline for repairs for a portion of 2009.

Exploration expenses from continuing operations for each of the last three years are shown in total in the following table, and amounts are reported by major operating area on pages F-41 and F-42 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)	**2010**	2009	2008
Dry holes	**$ 90.1**	125.3	129.5
Geological and geophysical	**65.1**	40.5	85.2
Other	**29.1**	16.2	17.7
	184.3	182.0	232.4
Undeveloped lease amortization	**108.0**	83.2	112.0
Total exploration expenses	**$292.3**	265.2	344.4

Dry hole expense was $35.2 million lower in 2010 than in 2009 despite a 50% increase in spending for exploratory drilling. Dry hole expense in the U.S. was lower in the current year mostly due to deferral of planned Gulf of Mexico drilling due to the moratorium imposed by the Federal government following the April 2010 blowout and oil spill at the Macondo well owned by other companies. Malaysian operations had lower dry hole expense in 2010 due to more successful exploratory drilling results and favorable adjustments to final costs on prior-year wells. Dry holes in the U.K. in 2010 primarily related to a decision to expense a well drilled in 2008 for which studies in 2010 indicated a lack of economical development options based on current pricing levels. Dry hole expense in Republic of the Congo was higher in 2010 than 2009 due to drilling more unsuccessful wells in the MPS block in the current year. Dry hole expense in 2010 in other foreign areas was less than in 2009 primarily due to an unsuccessful well offshore Australia in the prior year. Geological and geophysical (G&G) expenses were $24.6 million higher in 2010 than 2009. Areas of higher spending on seismic in the 2010 year included the Eagle Ford Shale area of South Texas, the MPN and

MPS blocks offshore Republic of the Congo and offshore Malaysia. These higher G&G costs in 2010 were somewhat offset by lower spending in the Tupper area of Western Canada and offshore Suriname. Other exploration costs in 2010 were $12.9 million above 2009 levels primarily due to higher administrative costs for operations in Suriname, Indonesia and Australia in the current year. Undeveloped leasehold amortization expense rose $24.8 million in 2010 compared to 2009, primarily due to higher amortization associated with lease acquisition costs in the Eagle Ford Shale area of South Texas, partially offset by less amortization expense in 2010 following sanction of development at the Tupper West property in August 2009.

Dry hole expense was $4.2 million lower in 2009 than 2008 due to more successful exploratory drilling results during a year with higher drilling capital expended. During 2009, lower dry hole costs in Malaysia and the U.S. was somewhat offset by higher costs in Australia and Republic of the Congo. G&G expenses were $44.7 million lower in 2009 compared to 2008. The reduction in G&G in 2009 was attributable to less spending on seismic in the Gulf of Mexico, the Tupper area in Western Canada, and offshore Sabah in Malaysia, but 2009 included higher spending for seismic covering the Semai II concession, offshore Indonesia. Other exploration costs were $1.5 million lower in 2009 compared to 2008 mostly due to less office costs allocable to Republic of the Congo exploration activities in the current year. Undeveloped leasehold amortization expense was $28.8 million lower in 2009 compared to 2008 mostly due to lower amortization for Tupper and Tupper West area leases in Western Canada, but partially offset by higher amortization costs for Eagle Ford Shale leases in South Texas in 2009.

An impairment charge of $5.2 million was recorded in 2009 to write-off the remaining costs of a poorly performing natural gas field in the Gulf of Mexico.

Depreciation, depletion and amortization expense for exploration and production continuing operations totaled $1,005.0 million in 2010, $775.8 million in 2009 and $527.8 million in 2008. The $229.2 million increase in 2010 was primarily caused by higher overall volumes of oil and natural gas sold during the current year. Additionally, a higher proportion of 2010 production was derived from fields brought onstream in recent years under a higher-cost development environment. The $248.0 million increase in 2009 compared to 2008 was primarily attributable to a combination of higher overall hydrocarbon production levels and start-up of new fields in the Gulf of Mexico, Western Canada and Republic of the Congo that had higher per-unit depreciation rates than older fields already on production.

The exploration and production business recorded expenses of $31.1 million in 2010, $25.5 million in 2009 and $23.5 million in 2008 for accretion on discounted abandonment liabilities. Because the abandonment liability is carried on the balance sheet at a discounted fair value, accretion must be recorded annually so that the liability will be recorded at full value at the projected time of abandonment. The $5.6 million increase in accretion expense in 2010 compared to 2009 was due to additional wells drilled during the latest year in several geographical areas and higher estimated abandonment costs for offshore operations in Malaysia and synthetic oil operations in Western Canada. The $2.0 million increase in accretion costs in 2009 compared to 2008 was mostly attributable to additional wells drilled in 2009 at the Kikeh and Sarawak fields, offshore Malaysia.

The effective income tax rate for exploration and production continuing operations was 41.7% in 2010, 40.8% in 2009 and 37.4% in 2008. The effective tax rate was slightly higher in 2010 than 2009 mostly due to tax barrels owed the government of Republic of the Congo under the production sharing agreement covering the Azurite field. More tax barrels were owed the government due to higher Azurite production levels in 2010. The effective tax rate was higher in 2009 than 2008 due to both higher expenses in foreign tax jurisdictions where no tax benefit can be currently recognized due to lack of sufficient revenue to realize a current benefit and a higher percentage of profits in Malaysia where the effective tax rate of 38% is higher than the effective rates in the U.S. and Canada. 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 activities in areas where current tax benefits cannot be recorded by the Company. Tax jurisdictions with no current tax benefit on expenses primarily include non-revenue generating areas in Malaysia, Suriname, Australia and Indonesia. 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 Blocks H and P, offshore Sabah, and Blocks PM 311/312, offshore Peninsula Malaysia.

At December 31, 2010, 10.8 million barrels of the Company's U.S. proved oil reserves and 23.8 billion cubic feet of the U.S. proved natural gas reserves were undeveloped. More than 70% of the total U.S. undeveloped reserves (on a barrel of oil equivalent basis) are associated with the Company's various deepwater Gulf of Mexico fields. Further drilling, facility construction and well workovers are required to move undeveloped reserves to developed. In the Western Canadian Sedimentary basin, total proved undeveloped natural gas reserves totaled 116.8 billion cubic feet, with the migration of these reserves, primarily in the Tupper and Tupper West areas, dependent on both development drilling and completion of processing and transportation facilities. In Block K Malaysia, all oil reserves of 14.8 million barrels for the Kakap field are undeveloped pending completion of facilities and development drilling directed by another company. Additionally, the Kikeh field had undeveloped oil reserves of 15.8 million barrels, which are subject to further development drilling before being moved to developed. Also in Malaysia, there were 133.7 billion cubic feet of undeveloped natural gas reserves at various fields offshore Sarawak at year-end 2010, which were held under this category pending completion of development drilling and facilities. On a worldwide basis, the Company spent approximately $1.27 billion in 2010, $1.34 billion in 2009 and $783 million in 2008 to develop proved reserves.

Refining and Marketing – The Company's refining and marketing (R&M) operations generated earnings of $149.1 million in 2010, $71.7 million in 2009 and $313.8 million in 2008. The R&M earnings improvement of $77.4 million in 2010 compared to 2009 was mostly attributable to more than a $0.03 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

2010. The R&M earnings decline of $242.1 million in 2009 compared to 2008 was driven primarily by significantly weaker margins in the U.S. retail fuel marketing business and lower refining margins in the U.K.

The Company has announced its intention to sell its U.S. refineries and U.K. refining and marketing operations in 2011.

The Company's R&M operations in the United States generated earnings of $183.8 million in 2010, $92.2 million in 2009 and $227.9 million in 2008. U.S. operations are further reported as segregated between manufacturing and marketing activities. U.S. manufacturing activities include two oil refineries and two ethanol production facilities, while U.S. marketing activities include retail and wholesale fuel marketing operations. U.S. manufacturing operations generated profits of $28.4 million in 2010 and $31.2 million in 2009, but incurred a loss of $39.8 million in 2008. The $2.8 million decline in manufacturing income in 2010 compared to 2009 was primarily caused by nonrecurring income of $32.6 million in 2009 from insurance settlements at the Meraux, Louisiana, refinery. The insurance settlements related to property damage from Hurricane Katrina in 2005 and damage caused by a refinery fire in 2003. Final insurance proceeds for Hurricane Katrina-related property damage exceeded amounts originally estimated to be recovered. Manufacturing results in 2010 benefited from higher crude oil throughputs at both U.S. refineries, which occurred despite an approximate six-week shutdown for a plant-wide turnaround at the larger Meraux refinery. Overall refining margins per barrel at the Company's two U.S. refineries were lower, however, in 2010 than during the prior year. The Meraux refinery ran a slightly higher mix of more expensive sweet crudes in 2010 and the refinery's product yield of higher value gasoline and distillates in 2010 was slightly below 2009 levels. The 2010 manufacturing profit included higher earnings from the Company's ethanol production facility in Hankinson, North Dakota. The Hankinson plant, which was acquired on October 1, 2009, was in operation for the full year of 2010 compared to three months of operations in 2009. In late 2010, the Company acquired an unfinished ethanol production facility in Hereford, Texas. The Company expects to complete construction and start-up the Hereford plant near the end of the first quarter 2011.

United States manufacturing results in 2009 were improved by $71.0 million compared to 2008 partially due to final insurance settlements in 2009 at the Meraux refinery for Hurricane Katrina-related property damage and a related crude oil spill and damage caused by a 2003 fire. The insurance settlements provided pretax benefits of $32.6 million during 2009. Additionally, 2009 had slightly improved refining margins for the Company's Gulf Coast refinery and higher asphalt sales volumes and asphalt margins at the Superior, Wisconsin refinery. The Hankinson ethanol facility generated profitable operations in the fourth quarter 2009 due to the favorable spread between ethanol sales prices and corn prices.

Unit margins (sales realization less costs of crude and other feedstocks, transportation to point of sale and refinery operating and depreciation expenses) for U.S. refining operations averaged $0.23 per barrel in 2010, compared to $0.75 per barrel in 2009 and $(1.48) per barrel in 2008. Meraux refinery throughput volumes of crude oil and other feedstocks averaged 112,578 barrels per day in 2010, 109,725 barrels per day in 2009 and 103,169 barrels per day in 2008. Superior refinery throughput volumes averaged 34,641 barrels per day of crude oil and other feedstocks in 2010, compared to 32,280 barrels per day in 2009 and 26,770 barrels per day in 2008. The Meraux refinery underwent a full plant turnaround in early 2010, and both U.S. refineries were temporarily shut-down for turnaround activities during 2008.

Marketing operations in the U.S. generated earnings of $155.4 million in 2010, $61.0 million in 2009 and $267.7 million in 2008. Profits in 2010 exceeded 2009 due to more than a $0.03 per gallon improvement in margins on fuel sold in the Company's retail marketing system. Additionally, the Company had higher profits in 2010 on sale of merchandise in this business. Total fuel sales volumes per station at Company operated sites in the U.S. averaged about 306,600 gallons per month during 2010, down 1.9% from the prior year.

United States marketing profits fell $206.7 million in 2009 compared to 2008. Fuel margins in the retail chain were hurt in 2009 by both lower demand for gasoline and diesel due to the weak economy and generally rising wholesale fuel costs caused by crude oil prices that rose gradually during the year. The large marketing profit in 2008 was caused by significant spreads between prices for wholesale and retail gasoline for a portion of that year.

United States refined product sales volumes averaged 450,100 barrels per day in 2010, compared to 432,700 barrels per day in 2009 and 427,490 barrels per day in 2008. The increases in both 2010 and 2009 were mostly attributable to more finished products produced at the U.S. refineries compared to the prior year, plus in 2010 a full year of ethanol production from the Hankinson facility acquired in October 2009, compared to three months of ethanol production in 2009. The retail marketing business built 51 stations in 2010, following additions of 23 stations in 2009. The U.S. retail marketing network included 1,099 stations at year-end 2010.

United Kingdom R&M operations incurred a loss of $34.7 million in 2010 compared to a loss of $20.5 million in 2009 and a profit of $85.9 million in 2008. The losses in 2010 and 2009 for U.K. R&M operations were primarily due to weak margins at the Company's Milford Haven, Wales, refinery. Additionally, in 2010 the refinery underwent approximately a two-month plant-wide turnaround that reduced crude oil throughputs in the most recent year. The refining margin was hurt by weak demand for refined products in the U.K. and Western Europe during the two-year period of 2009 and 2010. The soft demand led to an industry-wide oversupply of gasoline and diesel products in the area.

Unit margins in the United Kingdom averaged $(1.47) per barrel in 2010, $(0.28) per barrel in 2009 and $3.41 per barrel in 2008. Overall refined product sales volumes in the U.K. averaged 86,657 barrels per day in 2010, down 16% compared to 2009, primarily due to downtime associated with the turnaround at the Milford Haven refinery in 2010. Sales volumes of refined products in the U.K. declined 7% to 103,774 barrels per day in 2009 compared to 2008, essentially due to lower production of finished products at the Company's Milford Haven, Wales refinery.

Corporate – The after-tax costs of corporate activities, which include interest income, interest expense, foreign exchange gains and losses, and unallocated corporate overhead, were $157.9 million in 2010, $23.0 million in 2009 and $171.8 million in 2008.

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

The net cost of corporate activities in 2009 was $148.8 million lower than in 2008, primarily due to more favorable effects of foreign currency exchange. Foreign currency exchange after taxes was a gain of $33.3 million in 2009 compared to a loss after taxes of $87.8 million in 2008. The U.S. dollar generally weakened against the British pound sterling in 2009 after having gained significant ground on the U.K. currency during 2008. The weaker dollar in 2009 reduced the cost of U.S. dollar based liabilities for the sterling-functional U.K. R&M business. Foreign currency transaction effects in Canada, Malaysia and other foreign countries were generally insignificant for the full year 2009. The corporate area also benefited in 2009 from higher interest income of $10.9 million compared to 2008, principally due to $42.0 million ($27.0 million after taxes) of interest recognized on a recovery of U.S. federal royalties previously paid on certain production in the Gulf of Mexico. The interest on royalties more than offset lower interest income earned in 2009 on cash deposits and other longer-term investments as these amounts attracted much lower interest rates during 2009 compared to the prior year. Net interest expense, after capitalization of finance-related costs to development projects, was $17.8 million less in 2009 than 2008, principally due to lower interest rates charged on certain borrowings under the Company's credit facilities. Certain of these facilities charge interest based on a spread above LIBOR rates, which were held low in 2009 due to weakness in the overall economy. Administrative and depreciation expenses associated with corporate activities were both slightly higher in 2009 compared to 2008. Income tax expense in 2009 was significantly unfavorable to 2008 in the corporate area primarily due to the aforementioned favorable pretax variances for foreign exchange, interest income and net interest expense.

Capital Expenditures

As shown in the selected financial data on page 16 of this Form 10-K report, capital expenditures, including exploration expenditures, were $2.45 billion in 2010 compared to $2.21 billion in 2009 and $2.36 billion in 2008. These amounts included capital expenditures of $0.8 million in 2009 and $6.9 million in 2008 related to discontinued operations in Ecuador. Capital expenditures included $184.3 million, $182.0 million and $232.4 million, respectively, in 2010, 2009 and 2008 for exploration costs that were expensed. Capital expenditures for exploration and production continuing operations totaled $2.03 billion in 2010, $1.81 billion in 2009 and $1.93 billion in 2008, representing 83%, 82% and 82%, respectively, of the Company's total capital expenditures from continuing operations for these years. E&P capital expenditures in 2010 included $242.8 million for acquisition of undeveloped leases, which primarily included leases acquired in the Eagle Ford Shale area of South Texas and in the Tupper West area in Western Canada, $470.0 million for exploration activities, $1.30 billion for development projects, and $22.0 million for acquisition of proved properties in Canada. Development expenditures included $524.7 million at the Tupper and Tupper West natural gas areas in Western Canada; $46.8 million for deepwater fields in the Gulf of Mexico; $166.8 million for the Kikeh field in Malaysia; $160.4 million for natural gas and other development activities in SK Blocks 309/311; $58.1 million for development of the Kakap field in Block K, offshore Malaysia; $63.2 million for synthetic oil operations at the Syncrude project in Canada; $84.9 million for Western Canada heavy oil projects; $126.5 million for development of the Azurite field in Republic of the Congo; and $21.2 million for the Terra Nova and Hibernia oil fields, offshore Newfoundland. Exploration and production capital expenditures are shown by major operating area on page F-40 of this Form 10-K report.

Refining and marketing capital expenditures totaled $407.4 million in 2010, $375.9 million in 2009 and $426.2 million in 2008. These amounts represented 17%, 17% and 18% of capital expenditures from continuing operations of the Company in 2010, 2009 and 2008, respectively. Refining capital spending was $179.2 million in 2010 compared to $206.0 million in 2009 and $141.8 million in 2008. Refining spending in 2010 included costs to reduce benzene production and construct a new laboratory at Meraux; costs to meet compliance with ultra-low sulfur diesel and Mobile Source Air Toxic requirements at Superior; and costs to complete an expansion to increase crude oil throughput capacity at Milford Haven to 135,000 barrels per day. Refining spending in 2009 mostly included projects at Meraux for benzene reduction, a distillate hydrotreater revamp and crude oil storage expansion; a sulfur recovery project at Superior; and an ongoing crude oil capacity expansion project at Milford Haven. Refining capital in 2008 included project costs for additional sulfur recovery capacity and property acquisition and improvements at the Meraux, Louisiana, refinery, and a cogeneration energy plant at the Milford Haven, Wales, refinery. Marketing expenditures amounted to $183.2 million in 2010, $78.5 million in 2009 and $284.4 million in 2008. Marketing capital expenditures in 2010 were primarily associated with building new retail fueling stations and acquiring land for new station sites in the U.S. Marketing capital expenditures in 2009 were primarily associated with new station builds and other improvements within the U.S. retail gasoline station network. Marketing capital spending in 2008 was split between station construction costs and land acquisitions costs for existing and future retail gasoline stations. The Company added 51 stations within its U.S. retail gasoline network in 2010, after adding 23 in 2009 and 52 in 2008.

The Company spent $40.0 million in 2010 to acquire an unfinished ethanol production facility in Hereford, Texas. The Hereford facility is expected to be completed and in operation near the end of the 2011 first quarter. In 2009, the Company spent $92.0 million to acquire an ethanol production facility in Hankinson, North Dakota. The Hankinson ethanol plant was financed with an $82.0 million nonrecourse loan from the seller and a cash payment of $10.0 million. The nonrecourse loan was repaid in 2010. See Note D of the consolidated financial statements for further details about these acquisitions.

Cash Flows

Operating activities – Cash provided by operating activities was $3.13 billion in 2010, $1.86 billion in 2009 and $3.04 billion in 2008. Cash provided by continuing operations in 2010 was $1.26 billion more than 2009 primarily due to a drawdown of working capital other than cash in the current year and higher income from continuing operations. The working capital reduction in 2010 included cash receipts of $286.4 million related to recovery of federal royalties and associated interest income. Income associated with the royalty recovery was recorded in 2009, but the cash proceeds were collected in early 2010. Cash provided by continuing operations in 2009 was $1.18 billion less than in 2008 primarily due to lower net income. Cash provided by operating activities was reduced by expenditures for abandonment of oil and gas properties totaling $36.5 million in 2010, $48.7 million in 2009 and $9.2 million in 2008.

Investing activities – Cash proceeds from property sales classified as continuing operations were $2.2 million in 2010, $1.6 million in 2009 and $362.0 million in 2008. The 2008 proceeds related to sales of two Canadian assets, including the Company's interests in Berkana Energy and the Lloydminster heavy oil property, plus a sale of 35% of its working interest in the MPS block offshore Republic of the Congo. During 2009, the Company generated cash of $78.9 million from the sale of its 20% working interest in Block 16 in Ecuador. Operating results and cash flows associated with Ecuador operations have been classified as discontinued operations in the Company's consolidated financial statements. Property additions and dry hole costs used cash of $2.32 billion in 2010, $1.98 billion in 2009 and $2.18 billion in 2008. Cash used to pay for capital expenditures was higher in 2010 compared to 2009, but was lower in 2009 compared to 2008, with these variances essentially in line with changes in capital expenditures in each year. Cash of $2.39 billion, $2.53 billion and $1.04 billion was spent in 2010, 2009 and 2008, 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 $2.55 billion in 2010, $2.17 billion in 2009 and $623.1 million in 2008. Cash of $98.9 million in 2010, $30.3 million in 2009 and $57.6 million in 2008 was used for turnarounds at refineries and Syncrude. The increase in 2010 was attributable to plant-wide turnarounds for both the Meraux and Milford Haven refineries.

Financing activities – During 2010 and 2008, the Company used available cash flow to repay $414.0 million and $492.8 million, respectively, of debt. During 2009, the Company borrowed $243.5 million under debt agreements primarily to fund a portion of the Company's development capital expenditures. Cash proceeds from stock option exercises and employee stock purchase plans, including income tax benefits on stock options, amounted to $54.7 million in 2010, $16.9 million in 2009 and $50.0 million in 2008. In 2009, the Company paid $10.0 million to partially finance the acquisition of the Hankinson, North Dakota, ethanol plant; the remaining $82.0 million acquisition price was financed with a seller-provided nonrecourse loan. This nonrecourse loan was fully repaid in 2010. Cash used for dividends to stockholders was $201.4 million in 2010, $190.8 million in 2009 and $166.5 million in 2008. The Company raised its annualized dividend rate from $1.00 per share to $1.10 per share beginning in the third quarter of 2010. The Company had previously increased the annualized dividend rate from $0.75 per share to $1.00 per share beginning in the third quarter of 2008.

Financial Condition

Year-end working capital (total current assets less total current liabilities) totaled $619.8 million in 2010 and $1.19 billion in 2009. 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 $735.1 million below fair value at December 31, 2010. Cash and cash equivalents at the end of 2010 totaled $535.8 million compared to $301.1 million at year-end 2009.

Long-term debt, including nonrecourse loans, decreased by $413.8 million during 2010 and totaled $939.4 million at year-end 2010, representing 10.3% of total capital employed. Long-term debt decreased by $327.0 million in 2009. Stockholders' equity was $8.20 billion at the end of 2010 compared to $7.35 billion a year ago and $6.28 billion at the end of 2008. A summary of transactions in stockholders' equity accounts is presented on page F-6 of this Form 10-K report.

Other significant changes in Murphy's year-end 2010 balance sheet compared to 2009 included a $162.4 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 $616.6 million at year-end 2010 and $779.0 million at year-end 2009. These slightly longer-term investments were purchased in each year because of a tight supply of shorter-term securities available for purchase in Canada. A $4.0 million increase in accounts receivable in 2010 was caused by higher sales prices and volumes for crude oil and finished products sold on credit terms by the Company, mostly offset by collection in 2010 of a receivable recorded in the prior year associated with recovery of previously paid federal royalties, plus interest thereon, totaling $286.4 million. Inventory values were $28.2 million more at year-end 2010 than in 2009 mostly due to higher valued crude and refined products held in storage within downstream operations in the later year, but partially offset by less costs for unsold crude oil production held in inventory in the current year. Prepaid expenses increased $5.0 million in 2010 primarily due to higher prepaid income taxes in the U.K. Short-term deferred income tax assets were $65.5 million higher at year-end 2010 compared to 2009 due mostly to larger current temporary differences for expense deductions within downstream operations. Net property, plant and equipment increased by $1.30 billion in 2010 as a significant level of property additions during the year exceeded the additional depreciation and amortization expensed. Goodwill increased $2.2 million in 2010 due to a stronger Canadian dollar exchange rate versus the U.S. dollar. Deferred charges and other assets decreased $3.1 million mostly due to reclassification of long-term prepaid advances from this category to property, plant and equipment during 2010, but partially offset by higher turnaround costs spent and deferred in 2010 at the Meraux and Milford Haven refineries. Current maturities of long-term debt at year-end 2010 was essentially unchanged from 2009. Accounts payable increased by $698.4 million at year-end 2010 compared to 2009 primarily due to higher amounts owed for refinery crude oil purchases and for E&P drilling activities. Income taxes payable was $28.4 million lower at year-end 2010 than at the end of 2009, primarily due to less U.S. income tax liabilities owed in the current year. Other taxes payable were $41.0 million higher mostly due to more value added taxes owed by the U.K. downstream operations at year-end 2010 compared to 2009. Other accrued liabilities increased by $21.0 million in 2010 mostly due to a deposit received related to the pending sale of a natural gas storage asset in Spain and higher postemployment plan liabilities classified as a current liability at December 31, 2010. The current portion of deferred income tax liabilities increased $17.3 million in 2010 due to various short-term temporary differences for tax deductions in Canada. Noncurrent deferred income tax liabilities were $193.4 million higher at year-end 2010 mostly due to accelerated tax depreciation associated with the Company's 2010 capital expenditures, primarily in Malaysia and Canada. The liability associated with future asset retirement obligations increased by $78.3 million mostly due to higher estimated future costs to retire assets in the Gulf of Mexico and at synthetic oil operations in Western Canada. Deferred credits and other liabilities were $16.1 million more in 2010 compared to 2009 mostly due to higher noncurrent liabilities associated with postemployment benefit plans in the current year.

Murphy had commitments for future capital projects of approximately $1.30 billion at December 31, 2010, including $678.0 million for field development and future work commitments in Malaysia, and $118.3 million for costs to develop deepwater Gulf of Mexico fields.

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, 2010, the Company had access to a long-term committed credit facility in the amount of $1.905 billion. A total of $340.0 million was borrowed under the committed credit facility at year-end 2010. 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 2012. At December 31, 2010, the Company had uncommitted bank credit lines of approximately $430.0 million, but no borrowings were outstanding under these lines. The long-term debt to capital ratio was approximately 10.3% at year-end 2010. In September 2009, the Company filed a Form S-3 registration statement with the U.S. Securities and Exchange Commission which permits the offer and sale of debt and/or equity securities. The Company may use this shelf registration, if needed, in future years to raise debt or equity capital to fund operational requirements. This shelf registration expires in September 2012. Current financing arrangements are set forth more fully in Note F to the consolidated financial statements. The Company anticipates that it may be able to repay a portion of its long-term debt during 2011. This assumption is based on the anticipated sale of its three refineries and U.K. marketing assets during 2011, plus an ability to closely match its spending plans to cash inflows during the year. However, if the Company is unable to sell these downstream assets or if future oil and natural gas prices and/or refining and marketing margins weaken significantly, the Company may have to borrow under available credit facilities to fund ongoing development projects. The Company's ratio of earnings to fixed charges was 18.0 to 1 in 2010, 16.7 to 1 in 2009 and 28.3 to 1 in 2008.

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. Compliance with existing and anticipated environmental regulations affects our overall cost of business. Areas affected include capital costs to construct, maintain and upgrade equipment and facilities, in concert with ongoing operating costs for environmental compliance. Anticipated and existing regulations affect our capital expenditures and earnings, and they may affect our competitive position to the extent that regulatory requirements with respect to a particular production technology may give rise to costs that our competitors might not bear. Environmental regulations have historically been subject to frequent change by regulatory authorities, and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of such regulations on our 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 us 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 $139.3 million in 2010 and are projected to be $117.2 million in 2011.

The most significant of those laws and the corresponding regulations affecting our U.S. operations are:

- The U.S. Clean Air Act, which regulates air emissions
- The U.S. Clean Water Act, which regulates discharges into U.S. waters
- The U.S. Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which addresses liability for hazardous substance releases
- The U.S. Federal Resource Conservation and Recovery Act (RCRA), which regulates the handling and disposal of solid wastes
- 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 wells
- Regulations of the U.S. Department of the Interior governing offshore oil and gas operations.

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 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. We are 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.

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 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 our ordinary operations, we generate waste that falls within CERCLA’s definition of a “hazardous substance.” We may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which such hazardous substances have been disposed of or released into the environment. CERCLA also requires reporting of releases to the environment of substances defined as hazardous or extremely hazardous and must be reported to the National Response Center, if they exceed an EPA established reportable quantity.

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

We currently own or lease, and have in the past owned or leased, properties at which hazardous substances have been or are being handled. Although we have 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 us 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 our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws we 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, we are 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 Murphy’s net income, financial condition or liquidity in a future period. Although certain environmental expenditures are likely to be recovered by us from other sources, no assurance can be given that future recoveries from these sources will occur. Therefore, we have not recorded a benefit for likely recoveries as of December 31, 2010.

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. We generate non-hazardous solid wastes that are subject to the requirements of RCRA and comparable state statutes. Our operating sites also incur costs to handle and dispose of hazardous waste and other chemical substances. The types of waste and substances disposed of generally fall into the following categories: spent catalysts (usually hydrotreating catalysts); spent/used filter media; tank bottoms and API separator sludge; contaminated soils; laboratory and maintenance spent solvents; and industrial debris. 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.

We are 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 our operations. Under our 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 quarterly. Actual cash expenditures often occur one or more years after a liability is recognized.

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. To the best of our knowledge, there has been no such OPA90 claims made against Murphy.

The EPA has issued several standards applicable to the formulation of motor fuels, primarily related to the level of sulfur found in highway diesel and gasoline, which are designed to reduce emissions of certain air pollutants when the fuel is used. Several states have passed similar or more stringent regulations governing the formulation of motor fuels. The EPA's mandated requirements for low-sulfur gasoline became effective in 2008 and both of our U.S. refineries are capable of producing the required low-sulfur gasoline. Each of the U.S. refineries are also capable of producing ultra low-sulfur diesel (ULSD) as required by the EPA beginning in 2010. Under the Clean Air Act, the EPA has issued requirements pursuant to the Mobile Source Air Toxics (MSAT) regulation for the corporate annual average of benzene content in gasoline, which is not to exceed 0.62% by volume beginning January 1, 2011, with no individual facility to exceed 1.30% by July 2012. Equipment has been installed at the Meraux and Superior refineries to achieve MSTA compliance.

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 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. We maintain wastewater discharge permits for our facilities where required pursuant to the FWPCA and comparable state laws. We have also applied for all necessary permits to discharge storm water under such laws. We believe that compliance with existing permits and foreseeable new permit requirements will not have a material adverse effect on our net income, financial condition or liquidity in a future period.

Our U.S. operations are subject to the Federal Clean Air Act and comparable state and local statutes. We believe that our operations are in substantial compliance with these statutes in all states in which we operate. 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.

Under the EPA's Clean Air Act authority, the National Petroleum Refinery (NPR) Initiative (Global Consent Decree) was used by the EPA to undertake at virtually all U.S. refineries an investigation of four marquee compliance areas, including: (i) New Source Review/Prevention of Significant Deterioration for fluidized catalytic cracking units, heaters and boilers; (ii) New Source Performance Standards for flares, sulfur recovery units, fuel gas combustion devices (including heaters and boilers); (iii) Leak Detection and Repair requirements; and (iv) Benzene National Emissions Standards for Hazardous Air Pollutants. Murphy began negotiations with the EPA in 2005, but was interrupted by the events of Hurricane Katrina. The states of Louisiana and Wisconsin are both parties to the NPR. Negotiations with EPA resumed in 2007 and were essentially completed in 2010. Under the Global Consent Decree, the Company agreed to pay a fine of $1.25 million and committed to capital improvements that are anticipated to cost approximately $142 million over the next eight years.

Our Meraux, Louisiana, refinery is also currently negotiating with the Louisiana Department of Environmental Quality (LDEQ) regarding three Compliance Order/Notice of Proposed Penalty (CO/NOPP) notifications regarding air and water discharges. While we are in various stages of negotiations and/or settlement, the Company has proposed a settlement offer related to these CO/NOPP negotiations and has reached agreement either independently with the State of Louisiana or as a condition of settlement of the federal Global Consent Decree, with approval of the State of Louisiana. The Company does not expect the settlement of this matter to have a material adverse effect on Company's net income, financial condition or liquidity in a future period.

World leaders have held numerous discussions about the level of worldwide greenhouse gas emissions. As part of these discussions, the Kyoto Agreement was adopted in 1997 and was ratified by certain countries in which we operate or may operate in the future, with the United States being the primary country that has yet to ratify the agreement. While efforts were made at the Copenhagen Accord, held December 19, 2009, to strengthen the Kyoto Protocol which expires in 2012, the delegates to the 15th session of the Conference of the Parties (COP15) at Copenhagen agreed only to "take note" of the proceedings and did not ratify or agree to a successor to the Kyoto Protocol. We are unable to predict how U.S. regulations (if any) associated with the Kyoto Agreement will impact costs in future years. The European Union has adopted an Emissions Trading Scheme in response to the Kyoto Agreement in order to achieve reductions in greenhouse gas emissions. Our refining operations at Milford Haven currently have 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.

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. During 2010, U.S. federal legislation (Cap and Trade 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 to develop statewide or regional programs, each of which have or could impose mandatory reductions in greenhouse gas emissions. The impact of existing and pending climate change legislation, regulations, international treaties and accords could result in increased costs to (i) operate and maintain our facilities; (ii) install new emission controls on our facilities; and (iii) administer and manage any greenhouse gas emissions trading program. These actions could also impact the consumption of refined products, thereby affecting our refinery operations. The physical impacts of climate change present potential risks for severe weather (floods, hurricanes, tornadoes, etc.) at our Meraux, Louisiana, refinery in southern Louisiana and our offshore platforms in the Gulf of Mexico. Commensurate with this risk is the possibility of indirect financial and operational impacts to the Company from disruptions to the operations of major customers or suppliers caused by severe weather. The Company has repositioned itself to take advantage of potential climate change opportunities by acquiring renewable energy sources through the acquisition of two ethanol production facilities, thereby achieving a lower carbon footprint and an enhanced capability to meet governmental fuel standards. The Company is unable to predict at this time how much the cost of compliance with any future legislation or regulation of greenhouse gas emissions, or the cost impact of natural catastrophic events resulting from climate change, if it occurs, will be in future periods.

The Company recognizes the importance of environmental stewardship as a core component of its mission as a responsible international energy company and has implemented sufficient disclosure controls and procedures to capture and process climate-change related information. The Company'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. Further, in February 2009, our Board approved a worldwide environmental, health, and safety policy (the EHS Policy), which is available on the Company's Web site. In addition to requiring that the Company comply with all applicable EHS laws and regulations, the EHS Policy includes a directive that the Company will "continue to minimize the impact of our operations, products and services on the environment by implementing economically feasible projects that promote energy efficiency and use natural resources effectively." We likewise apply this conscientious approach to the issue of climate change. As a companion to the EHS Policy, the Company's Web site also contains a statement on climate change. Not only does this statement on climate change include our goal of reducing greenhouse gas emissions on an absolute basis while growing our upstream and certain downstream operations, the information on our Web site describes actions we have already taken to move towards that goal. While we are admittedly in the early stages of a process that will grow over time, the Company has formed an internal Climate Change Workgroup to address emerging climate change issues and improve energy efficiencies. This Climate Change Workgroup is working with the respective business units to focus on comprehensive climate change efforts aimed at preparing the company to succeed in a world challenged to reduce greenhouse gas emissions. These efforts include incorporating climate change into our planning processes, reducing our own 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. The initiatives cited above demonstrate the Company's commitment regarding environmental issues, which are at the forefront of today's global public policy dialogue.

Murphy is actively engaged in the legislative and regulatory process, both nationally and internationally, in response to climate change issues and to protect our competitive advantage. Additionally, Murphy participates in the Massachusetts Institute of Technology (MIT) Joint Program on the Science and Policy of Global Change.

Safety Matters

We are 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 our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with OSHA requirements, including general industry standards, record-keeping requirements and monitoring of occupational exposure to regulated substances.

In 2007, OSHA announced a National Emphasis Program (NEP) for inspecting all refineries in the U.S. for compliance with OSHA's Process Safety Management (PSM) regulations. OSHA conducted an inspection of our Meraux, Louisiana, refinery from July-September 2009, and on December 29, 2009, OSHA issued several compliance related citations and a proposed penalty. The matter was settled with OSHA through payment of a $63,000 penalty with all of the OSHA items abated in 2010, with concurrence from OSHA that the NEP event is now closed.

Other Matters

Oil Spill Response Plan – Each Murphy offshore facility in the Gulf of Mexico has in place an Emergency Evacuation Plan (EEP) and an Oil Spill Response Plan (OSRP). In the event of an explosion, personnel would be evacuated immediately in accordance with the EEP and the OSRP would be activated if needed. In the event of an oil spill, the OSRP would be executed as needed. The EEP is approved by U.S. Coast Guard (USCG) and the OSRP is approved by Bureau of Ocean Energy Management (formerly the Minerals Management Service). 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. We have further contracted with another company to utilize their equipment for oil containment should a well blowout occur.

Impact of inflation – General inflation was moderate during the last three years in most countries where the Company operates; however, the Company's revenues and capital and operating costs are influenced to a larger extent by specific price changes in the oil and gas and allied industries than by changes in general inflation. Crude oil and petroleum product prices generally reflect the balance between supply and demand, with crude oil prices being particularly sensitive to OPEC production levels and/or attitudes of traders concerning supply and demand in the near future. Natural gas prices are affected by supply and demand, which are often affected by the weather and by the fact that delivery of gas is generally restricted to specific geographic areas. Prices for oil field goods and services have generally risen (with certain of these price increases such as drilling rig day rates having been significant at times) during the last few years primarily driven by high demand for such goods and services when oil and gas prices were strong. As noted earlier, oil and natural gas prices have been extremely volatile over the last several years. Oil prices were very strong in early to mid 2008, then fell precipitously in late 2008 and into early 2009, then have generally strengthened since that time. The prices for oil field goods and services generally rise in periods of higher oil prices and do not usually decline as significantly as oil and gas prices in a lower price environment. Should oil prices continue to rise in future periods, the Company anticipates that prices for certain oil field equipment and services could rise sharply. Due to the volatility of oil and natural gas prices, it is not possible to determine what effect these prices will have on the future cost of oil field goods and services.

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

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

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

The Company adopted new accounting guidance for noncontrolling interests in consolidated financial statements effective January 1, 2009. This guidance is applied prospectively, except for presentation and disclosure requirements which are applied retrospectively. This guidance required noncontrolling interests to be reclassified as equity, and consolidated net income and comprehensive income shall include the respective results attributable to noncontrolling interests. The adoption of this guidance did not have a significant effect on the Company's consolidated financial statements.

The Company adopted new accounting guidance covering business combinations effective January 1, 2009. The new guidance established principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquired business. It also established how to recognize and measure goodwill acquired in the business combination or a gain from a bargain purchase, if applicable. This guidance impacts the recognition and measurement of assets and liabilities in business combinations that occur beginning in 2009. Assets and liabilities that arose from business combinations that occurred prior to 2009 are not affected by this guidance. The adoption of this guidance did not have a significant effect on the Company's financial statements for the year ended December 31, 2009. The Company is unable to predict how the application of this guidance will affect its financial statements in future periods.

The Company adopted new accounting guidance which addressed disclosures about derivative instruments and hedging activities in January 2009. This guidance expanded required disclosures regarding derivative instruments to include qualitative information about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments, and disclosures about credit-risk related contingent features in derivative agreements. See Note L of this Form 10-K for further disclosures.

In 2009, the Company adopted new accounting guidance for determining whether instruments granted in share-based payment transactions are participating securities. This guidance specified that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings per share (EPS) calculation under the two-class method, and also required that all prior-period EPS calculations be adjusted retrospectively. The adoption of this guidance did not have a significant impact on the Company's prior-period EPS calculations.

The Company adopted new accounting guidance addressing certain equity method investment accounting considerations in January 2009. The guidance, which has been applied prospectively, addressed how to initially measure contingent consideration for an equity method investment, how to recognize other-than-temporary impairments of an equity method investment, and how an equity method investor is to account for a share issuance by an investee. The adoption of this guidance did not have a significant impact on the Company's consolidated financial statements.

The Company adopted new accounting guidance addressing subsequent events effective June 30, 2009. The guidance clarified the accounting for and disclosure of subsequent events that occur after the balance sheet date through the date of issuance of the applicable financial statements. The adoption of this guidance did not have a significant effect on the Company's consolidated financial statements.

The FASB's Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles guidance became effective for interim and annual periods ended after September 15, 2009, and it recognized the FASB Accounting Standards Codification as the single source of authoritative nongovernment U.S. generally accepted accounting principles. The codification superseded all existing accounting standards documents issued by the FASB, and established that all other accounting literature not included in the codification is considered nonauthoritative. Although the codification did not change U.S. generally accepted accounting principles, it did reorganize the principles into accounting topics using a consistent structure. The codification also included relevant U.S. Securities and Exchange Commission guidance following the same topical structure. For periods ending after September 15, 2009, all references to U.S. generally accepted accounting principles use the new topical guidelines established with the codification. Otherwise, this new standard did not have a material impact on the Company's consolidated financial statements.

The FASB has provided additional guidance regarding disclosures about postretirement benefit plan assets, including how asset investment allocation decisions are made, the fair value of each major category of plan assets, and how fair value is determined for each major asset category. This guidance was effective for the Company as of December 31, 2009. Upon adoption, no comparative disclosures were required for earlier years presented. See Note K of this Form 10-K for additional disclosures.

In December 2008, the U.S. Securities and Exchange Commission (SEC) adopted revisions to oil and natural gas reserves reporting requirements which became effective for the Company at year-end 2009. The primary changes to reserves reporting included:

- A revised definition of proved reserves, including the use of unweighted average oil and natural gas prices in effect at the beginning of each month during the year to compute such reserves,
- Expanding the definition of oil and gas producing activities to include non-traditional and unconventional resources, which includes the Company's Canadian synthetic oil operations at Syncrude,
- Allowing companies to voluntarily disclose probable and possible reserves in SEC filings,
- Amending required proved reserve disclosures to include separate amounts for synthetic oil and gas,
- Expanded disclosures of proved undeveloped reserves, including discussion of such proved undeveloped reserves five years old or more, and
- Disclosure of the qualifications of the chief technical person who oversees the Company's overall reserve process.

The Company utilized this new guidance at December 31, 2010 and 2009 to determine its proved reserves and to develop associated disclosures. The Company chose not to provide voluntary disclosures of probable and possible reserves in this Form 10-K. In January 2010, the FASB issued guidance that aligned its oil and gas reporting requirements and effective date with the SEC's guidance described above.

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

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

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

  The Company's proved reserves of oil and natural gas are presented on pages F-38 and F-39 of this Form 10-K. The positive revision in U.S. proved oil reserves in 2010 was primarily associated with better than anticipated performance of wells at the Thunder Hawk and Medusa fields in the Gulf of Mexico. Better well performance at the Hibernia and Terra Nova fields led to favorable proved oil reserve revisions in Canada in 2010. Proved oil reserves for Canadian synthetic oil operations had a positive revision in 2010 primarily due to a lower royalty. The positive proved oil reserve revision in Malaysia in 2010 primarily related to better well performance at the Kikeh field. A positive proved oil reserve revision in Republic of the Congo in 2010 was attributable to improved terms under the production sharing agreement that allocated a larger share of production at the Azurite field to the account of the Company beginning in October 2010. A favorable oil reserve revision in 2009 in the United States was attributable to favorable performance of the Thunder Hawk and Front Runner fields and federal royalty relief for various deepwater fields. A favorable conventional oil revision in Canada in 2009 was caused by performance of the Terra Nova field and improved heavy oil pricing which added reserves in the Seal area. Due to changes in the SEC's definition of proved oil reserves, which were first effective as of December 31, 2009, synthetic oil reserves are now included as proved oil reserves. Consequently, total synthetic oil reserves as of January 1, 2009 of 131.6 million barrels were added to total oil reserves in 2009. The positive revision to synthetic oil reserves during 2009 was attributable to lower royalties compared to a year ago. An unfavorable revision to oil reserves in Malaysia in 2009 was due to current-year drilling results for a well in the Kikeh field, along with reduced entitlements at Kikeh and West Patricia due to increased prices at year-end 2009 compared to year-end 2008. Oil reserves in the U.K. reflected an unfavorable revision in 2009 because of an anticipated reduction in life expectancy for major equipment at the Schiehallion project. An unfavorable U.S. oil revision in 2008 resulted from updated reservoir modeling of one field in the deepwater Gulf of Mexico. An unfavorable revision in Canada in 2008 was related to low heavy oil prices at year-end, but this was partially offset by a favorable impact from better field performance in 2008 at Hibernia. A favorable oil reserve revision in Malaysia in 2008 was attributable to better than anticipated drilling results and additional drilling opportunities in the main reservoir at the Kikeh field, coupled with better reservoir performance and artificial lift improvements at the West Patricia field.

  Proved natural gas reserves in the U.S. had positive revisions in 2010 due to better well performance at the Thunder Hawk and Mondo fields in the Gulf of Mexico. The positive gas reserve revision in Canada in 2010 was attributable to performance at various wells in the Tupper area of British Columbia. Proved reserves of natural gas in Malaysia were revised downward in 2010 due to higher prices leading to a lower future entitlement percentage for the Company. Positive gas reserve revisions in the U.K. in 2010 were attributable to better well performance at all gas producing fields. In 2009, a positive U.S. gas reserve revision was caused by favorable performance of the Thunder Hawk, Front Runner and Mondo NW fields as well as federal royalty relief for various deepwater fields. In Malaysia, a combination of increased entitlements due to pricing and drilling performance at the Sarawak gas project led to positive gas revisions in 2009. Gas reserves in the U.K. were favorably revised in 2009 because of the Amethyst field gas compression project and better Mungo field performance. An unfavorable natural gas reserve revision in Malaysia in 2008 was related to entitlement adjustments under the production sharing contract for Blocks SK 309 and SK 311 and gas volumes lost due to operational delays that restricted sales volumes at the Kikeh field, offshore Sabah.

The Company cannot predict the type of oil and natural gas reserve revisions that will be required in future periods.

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

  In some cases, a determination of whether a drilled well has found proved reserves cannot be made immediately. This is generally due to the need for a major capital expenditure to produce and/or evacuate the hydrocarbon(s) found. The determination of whether to make such a capital expenditure is, in turn, usually dependent on whether additional exploratory wells find a sufficient quantity of additional reserves. Under current accounting rules, the Company holds well costs in Property, Plant and Equipment in the Consolidated Balance Sheet when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

  Based on the time required to complete further exploration and appraisal drilling in areas where hydrocarbons have been found but proved reserves have not been booked, dry hole expense may be recorded one or more years after the original drilling costs are incurred. In 2010, a dry hole was recorded for a well in the North Sea that was drilled in 2008. Extensive evaluations of this oil discovery determined in 2010 that recovery of hydrocarbons was not economical in the current price environment. There were no dry holes in 2009 or 2008 that were drilled in prior years.

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

  In making its impairment assessments involving exploration and production property and equipment, the Company must make a number of projections involving future oil and natural gas sales prices, future production volumes, and future capital and operating costs. Due to the volatility of world oil and gas markets, the actual sales prices for oil and natural gas have often been quite different from the Company's projections. Estimates of future oil and gas production and sales volumes are based on a combination of proved and risked probable and possible reserves. Although the estimation of reserves and future production is uncertain, the Company believes that its estimates are reasonable; however, there have been cases where actual production volumes were higher or lower than projected and the timing was different than the original projection. The Company adjusts reserves and production estimates as new information becomes available. The Company generally projects future costs by using historical costs adjusted for both assumed long-term inflation rates and known or expected changes in future operations. Although the projected future costs are considered to be reasonable, at times, costs have been higher or lower than originally estimated. In assessing potential impairment involving refining and marketing assets, the Company evaluates its properties when circumstances indicate that carrying value of an asset may not be recoverable from future cash flows. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events, which include projections of future margins, future capital expenditures and future operating expenses. Future marketing or operating decisions, such as closing or selling certain assets, and future regulatory or tax changes could also impact the Company's conclusion about potential asset impairment. Impairment expense of $5.2 million was recorded in 2009 to write-off the remaining carrying value of one underperforming natural gas field in the Gulf of Mexico. Based on an evaluation of expected future cash flows from properties at year-end 2010, 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 2010. In addition, one or a combination of factors such as lower future sales prices, lower future production, higher future costs, lower future margins on refining and marketing sales, or the actions of government authorities could lead to impairment expenses in future periods. Based on these unknown future factors as described herein, the Company cannot predict the amount or timing of impairment expenses that may be recorded in the future.

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

- *Accounting for retirement and postretirement benefit plans* – Murphy Oil and certain of its subsidiaries maintain defined benefit retirement plans covering most of its full-time employees. The Company also sponsors health care and life insurance benefit plans covering most retired U.S. employees. The expense associated with these plans is determined by management based on a number of assumptions and with consultation assistance from qualified third-party actuaries. The most important of these assumptions for the retirement plans involve the discount rate used to measure future plan obligations and the expected long-term rate of return on plan assets. For the retiree medical and insurance plans, the most important assumptions are the discount rate for future plan obligations and the health care cost trend rate. Discount rates are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate which is the basis for selecting the discount rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Anticipated health care cost trend rates are determined based on prior experience of the Company and an assessment of near-term and long-term trends for medical and drug costs.

  Based on bond yields at year-end 2010, the Company has used a discount rate of 5.66% at year-end 2010 and beyond for the primary U.S. plans. Although the Company presently assumes a return on plan assets of 6.50% for the primary U.S. plan, it periodically reconsiders the appropriateness of this and other key assumptions. The smoothing effect of current accounting regulations tends to buffer the current year's pension expense from wide swings in liabilities and asset valuations. The Company's normal annual retirement and postretirement plan expenses are expected to increase slightly in 2011 compared to 2010 based on the effects of a growing employee base. In 2010, the Company paid $20.7 million into various retirement plans and $3.9 million into postretirement plans. In 2011, the Company is expecting to fund payments of approximately $39.3 million into various retirement plans and $6.0 million for postretirement plans. The Company could be required to make additional and more significant funding payments to retirement plans in future years. Future required payments and the amount of liabilities recorded on the balance sheet associated with the plans could be unfavorably affected if the discount rate declines, the actual return on plan assets falls below the assumed return, or the health care cost trend rate increase is higher than expected. As described above, the Company's retirement and postretirement expenses are sensitive to certain assumptions, primarily related to discount rates and assumed return on plan assets. A 0.5% decline in the discount rate would increase 2011 annual retirement and postretirement expenses by $6.6 million and $1.0 million, respectively, and a 0.5% decline in the assumed rate of return on plan assets would increase 2011 retirement expense by $2.1 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 2010 under such contractual obligations and arrangements are shown below.

		Amount of Obligation			
(Millions of dollars)	Total	2011	2012-2013	2014-2015	After 2015
Total debt including current maturities	$ 939.4	–	689.9	0.1	249.4
Operating leases	983.9	166.0	288.7	239.6	289.6
Purchase obligations	1,944.5	1,341.7	440.8	57.4	104.6
Other long-term liabilities	698.6	42.2	25.6	106.9	523.9
Total	$4,566.4	1,549.9	1,445.0	404.0	1,167.5

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 amount of commitments as of December 31, 2010 that expire in future periods is shown below.

		Amount of Commitment			
(Millions of dollars)	Total	2011	2012-2013	2014-2015	After 2015
Financial guarantees	$ 7.8	–	–	3.8	4.0
Letters of credit	223.4	219.6	–	–	3.8
Total	$231.2	219.6	–	3.8	7.8

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 2010 includes 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, a natural gas transportation contract for the Tupper area in Western Canada and a hydrogen purchase contract for the Meraux refinery. The leases call for future monthly net lease payments through 2015 at Kikeh, through 2016 at Azurite, through 2014 at Thunder Hawk and through 2012 at West Patricia. The Tupper transportation contract requires minimum monthly payments through 2018. The Meraux refinery contract to purchase hydrogen ends in 2021. The hydrogen contract requires a monthly minimum base facility charge whether or not any hydrogen is purchased. Future required minimum annual payments under these arrangements are included in the contractual obligation table shown above.

Outlook

Prices for the Company's primary products are often quite volatile. The price for crude oil is primarily attributable to the level of demand for energy. In January 2011, West Texas Intermediate crude oil traded in a band between $86 and $92 per barrel. NYMEX natural gas traded in a band of $4.30 to $4.70 per MMBTU during this same time. U.S. refining margins in January 2011 were somewhat stronger than in late 2010, but U.S. retail marketing margins were squeezed by higher wholesale fuel costs during this period. The Company continually monitors the prices for its main products and often alters its operations and spending based on these prices.

The Company's capital expenditure budget for 2011 was prepared during the fall of 2010 and based on this budget capital expenditures are expected to be slightly higher than 2010 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 2011 budget, but North American natural gas prices have generally trailed the budgeted prices. Based on a recent review of capital expenditure projects, capital expenditures in 2011 are projected to total approximately $2.25 billion. Of this amount, $2.0 billion or about 88%, is allocated for the exploration and production program. Geographically, E&P capital is spread approximately as follows: 23% each for the United States and Malaysia, 39% for Canada and 15% for all other areas. Spending in the U.S. is primarily associated with development and exploration programs in the Eagle Ford Shale. The Company believes that budgeted 2011 spending for exploration and development activities in the Gulf of Mexico is at risk due to the U.S. government's delay in permitting all such activities following the Macondo incident in 2010. In Malaysia, the majority of the spending is for continued development of natural gas fields in Blocks SK 309 and SK 311 offshore Sarawak and at the Kikeh and Kakap fields in Block K. Approximately one-half of Canadian spending in 2011 will relate to natural gas development activities at the Tupper and Tupper West areas in Western Canada, with the remainder to be spent on continued development of existing oil fields. Other spending is primarily in Republic of the Congo for continued development of the Azurite offshore field and further exploration drilling in the MPS block. Refining and marketing expenditures in 2011 should be about $265 million, or 12% of the Company total, including funds for construction of additional U.S. retail gasoline stations. Capital and other expenditures will be routinely reviewed during 2011 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 2011 using operating cash flow, but will supplement funding where necessary using borrowings under available credit facilities. The Company's 2011 budget calls for a partial pay down of long-term debt during the year, primarily based on the assumption that worldwide refining and U.K. marketing assets will be sold during 2011. If oil and/or natural gas prices weaken or refining and U.K. marketing assets are not sold, actual cash flow generated from operations or asset dispositions could be reduced such that borrowings might be required during the year to maintain funding of the Company's ongoing development projects.

The Company currently expects production in 2011 to average between 200,000 and 210,000 barrels of oil equivalent per day. A key assumption in projecting the level of 2011 Company production is the anticipated ramp up of natural gas production following a February 2011 start-up at the Tupper West area in Western Canada. Other key assumptions include the timing of and ramp-up of oil production from well workovers at the Kikeh field and well performance at the Azurite field offshore Republic of the Congo. In addition, continued reliability of production at significant operations such as Syncrude, Hibernia and Terra Nova and the continued demand for natural gas from our offshore Malaysia fields are necessary to achieve the anticipated 2011 production levels.

Forward-Looking Statements

This Form 10-K contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. These statements, which express management's current views concerning future events or results, are subject to inherent risks and uncertainties. Factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements include, but are not limited to, the volatility and level of crude oil and natural gas prices, the level and success rate of our exploration programs, our ability to maintain production rates and replace reserves, customer demand for our products, political and regulatory instability, and uncontrollable natural hazards. For further discussion of risk factors, see Item 1A. Risk Factors, which begins on page 11 of this Annual Report on Form 10-K. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

There were short-term commodity derivative contracts in place at December 31, 2010 to hedge the value of about 0.1 million barrels of crude oil at the Company's refineries. Additionally, on this date the Company had open fixed-price corn purchase commitments of approximately 7.0 million bushels of corn expected to be purchased and processed at the Company's ethanol production facility. The Company also had open derivative contracts at that date to sell 7.5 million bushels of corn at these fixed prices and buy it back at future prices in effect at the time the corn is actually purchased. A 10% increase in the respective benchmark price of these commodities would have reduced the recorded asset associated with these derivative contracts by approximately $1.6 million, while a 10% decrease would have increased the recorded asset by a similar amount. Changes in the fair value of the Company's derivative contracts generally offset the changes in the value for an equivalent volume of these feedstocks.

There were short-term derivative foreign exchange contracts in place at December 31, 2010 to hedge the value of U.S. dollars against two foreign currencies. A 10% strengthening of the U.S. dollar against these foreign currencies would have reduced the recorded net asset associated with these contracts by approximately $37.4 million, while a 10% weakening of the U.S. dollar would have increased the recorded net asset by approximately $45.6 million. Changes in the fair value of these derivative contracts generally offset the financial statement impact of an equivalent volume of foreign currency exposures associated with other assets and/or liabilities.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages F-1 through F-45, which follow page 43 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, 2010, the principal executive officer and principal financial officer of Murphy Oil Corporation have concluded that the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective to ensure that the information required to be disclosed by Murphy Oil Corporation in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Murphy's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Management has conducted an evaluation of the effectiveness of our internal control over financial reporting based on the criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, management has concluded that our internal control over financial reporting was effective as of December 31, 2010. Our report is included on page F-2 of the annual report. KPMG LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2010 and their report is also included on page F-2 of this annual report.

There were no changes in the Company's internal controls over financial reporting that occurred during the fourth quarter of 2010 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 page 14 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 11, 2011 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 11, 2011 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 11, 2011 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 11, 2011 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 11, 2011 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.

2. Financial Statement Schedules

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

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

Exhibit No.		Incorporated by Reference to
*3.1	Certificate of Incorporation of Murphy Oil Corporation as amended, effective May 11, 2005	
3.2	By-Laws of Murphy Oil Corporation as amended effective February 3, 2010	Exhibit 3.2 of Murphy's Form 8-K report filed February 4, 2010
4	Instruments Defining the Rights of Security Holders. Murphy is party to several long-term debt instruments in addition to those in Exhibit 4.1 and 4.2, none of which authorizes securities exceeding 10% of the total consolidated assets of Murphy and its subsidiaries. Pursuant to Regulation S-K, item 601(b), paragraph 4(iii)(A), Murphy agrees to furnish a copy of each such instrument to the Securities and Exchange Commission upon request.	

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

[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.

Exhibit No.		Incorporated by Reference to
99.4	Form of non-employee director restricted stock award	Exhibit 99.4 of Murphy's Form 10-K report for the year ended December 31, 2006
99.5	Form of non-employee director restricted stock unit award	Exhibit 99.5 of Murphy's Form 10-K report for the year ended December 31, 2008
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	

Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). Users of this data are advised pursuant to Rule 406T of Regulation S-T that the interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of section 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise not subject to liability under these sections. The financial information contained in the XBRL-related documents is "unaudited" or "unreviewed."

SIGNATURES

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

MURPHY OIL CORPORATION

By DAVID M. WOOD
David M. Wood, President

Date: February 28, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 28, 2011 by the following persons on behalf of the registrant and in the capacities indicated.

WILLIAM C. NOLAN JR.
William C. Nolan Jr., Chairman and Director

R. MADISON MURPHY
R. Madison Murphy, Director

DAVID M. WOOD
David M. Wood, 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

CLAIBORNE P. DEMING
Claiborne P. Deming, Director

CAROLINE G. THEUS
Caroline G. Theus, Director

ROBERT A. HERMES
Robert A. Hermes, Director

KEVIN G. FITZGERALD
Kevin G. Fitzgerald, Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

JAMES V. KELLEY
James V. Kelley, Director

JOHN W. ECKART
John W. Eckart
Vice President and Controller
(Principal Accounting Officer)

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REPORT OF MANAGEMENT – CONSOLIDATED FINANCIAL STATEMENTS

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

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

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

Our report of management covering internal control over financial reporting and the associated report of the independent registered public accounting firm can be found at page F-2.

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, 2010 and 2009, and the related consolidated statements of income, comprehensive income, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2010. 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, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, 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, 2010, 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, 2011 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
February 28, 2011

REPORT OF MANAGEMENT – INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Management has conducted an evaluation of the effectiveness of our internal control over financial reporting based on the criteria set forth in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2010.

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, 2010, 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, 2010, 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, 2010 and 2009, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2010, and our report dated February 28, 2011 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
February 28, 2011

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(Thousands of dollars except per share amounts)*	**2010**	2009	2008
Revenues			
Sales and other operating revenues	**$23,401,117**	18,918,181	27,360,625
Gain on sale of assets	**884**	3,709	133,717
Interest and other income (loss)	**(56,930)**	90,502	(62,011)
Total revenues	**23,345,071**	19,012,392	27,432,331
Costs and Expenses			
Crude oil and product purchases	**18,142,253**	14,547,589	21,649,742
Operating expenses	**1,967,209**	1,621,854	1,657,427
Exploration expenses, including undeveloped lease amortization	**292,264**	265,172	344,406
Selling and general expenses	**279,164**	242,266	228,490
Depreciation, depletion and amortization	**1,164,782**	919,055	667,265
Impairment of properties	**–**	5,240	–
Accretion of asset retirement obligations	**31,858**	26,154	24,484
Redetermination of Terra Nova working interest	**18,582**	83,498	–
Interest expense	**53,172**	53,005	73,611
Interest capitalized	**(18,444)**	(28,614)	(31,459)
Total costs and expenses	**21,930,840**	17,735,219	24,613,966
Income from continuing operations before income taxes	**1,414,231**	1,277,173	2,818,365
Income tax expense	**616,150**	536,656	1,073,616
Income from continuing operations	**798,081**	740,517	1,744,749
Income (loss) from discontinued operations, net of income taxes	**–**	97,104	(4,763)
Net Income	**$ 798,081**	837,621	1,739,986
Income per Common Share – Basic			
Income from continuing operations	**$ 4.16**	3.88	9.20
Income (loss) from discontinued operations	**–**	.51	(.02)
Net Income – Basic	**$ 4.16**	4.39	9.18
Income per Common Share – Diluted			
Income from continuing operations	**$ 4.13**	3.85	9.08
Income (loss) from discontinued operations	**–**	.50	(.02)
Net Income – Diluted	**$ 4.13**	4.35	9.06
Average Common shares outstanding – basic	**191,830,357**	190,767,077	189,608,846
Average Common shares outstanding – diluted	**193,157,814**	192,468,450	192,133,672

See notes to consolidated financial statements, page F-8.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

December 31 *(Thousands of dollars)*	**2010**	2009
Assets		
Current assets		
Cash and cash equivalents	**$ 535,825**	301,144
Canadian government securities with maturities greater than 90 days at the date of acquisition	**616,558**	779,025
Accounts receivable, less allowance for doubtful accounts of $7,954 in 2010 and $7,761 in 2009	**1,467,311**	1,463,297
Inventories, at lower of cost or market		
Crude oil and blend stocks	**147,256**	128,936
Finished products	**388,162**	384,250
Materials and supplies	**226,795**	220,796
Prepaid expenses	**88,241**	83,218
Deferred income taxes	**80,545**	15,029
Total current assets	**3,550,693**	3,375,695
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $6,040,996 in 2010 and $4,714,826 in 2009	**10,367,847**	9,065,088
Goodwill	**42,850**	40,652
Deferred charges and other assets	**271,853**	274,924
Total assets	**$14,233,243**	12,756,359
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long-term debt	**$ 41**	38
Accounts payable	**2,237,920**	1,539,523
Income taxes payable	**358,764**	387,164
Other taxes payable	**206,951**	165,934
Other accrued liabilities	**109,918**	88,949
Deferred income taxes	**17,316**	–
Total current liabilities	**2,930,910**	2,181,608
Long-term debt	**939,350**	1,353,183
Deferred income taxes	**1,212,213**	1,018,767
Asset retirement obligations	**555,248**	476,938
Deferred credits and other liabilities	**395,972**	379,837
Stockholders' equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued	**–**	–
Common Stock, par $1.00, authorized 450,000,000 shares at December 31, 2010 and 2009, issued 193,293,526 shares at December 31, 2010 and 191,797,600 shares at December 31, 2009	**193,294**	191,798
Capital in excess of par value	**767,762**	680,509
Retained earnings	**6,800,992**	6,204,316
Accumulated other comprehensive income	**449,428**	287,187
Treasury stock	**(11,926)**	(17,784)
Total stockholders' equity	**8,199,550**	7,346,026
Total liabilities and stockholders' equity	**$14,233,243**	12,756,359

See notes to consolidated financial statements, page F-8.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(Thousands of dollars)*	**2010**	2009	2008
Operating Activities			
Net income	**$ 798,081**	837,621	1,739,986
Adjustments to reconcile net income to net cash provided by operating activities			
(Income) loss from discontinued operations	–	(97,104)	4,763
Depreciation, depletion and amortization	**1,164,782**	919,055	667,265
Impairment of long-lived assets	–	5,240	–
Amortization of deferred major repair costs	**39,110**	26,103	27,294
Expenditures for asset retirements	**(36,506)**	(48,694)	(9,240)
Dry hole costs	**90,125**	125,244	129,459
Amortization of undeveloped leases	**108,026**	83,213	112,052
Accretion of asset retirement obligations	**31,858**	26,154	24,484
Deferred and noncurrent income tax charges	**143,388**	97,213	233,076
Pretax gains from disposition of assets	**(884)**	(3,709)	(133,717)
Net decrease (increase) in noncash operating working capital	**639,566**	(194,690)	93,710
Other operating activities – net	**151,012**	90,001	35,304
Net cash provided by continuing operations	**3,128,558**	1,865,647	2,924,436
Net cash provided (required) by discontinued operations	–	(1,014)	115,476
Net cash provided by operating activities	**3,128,558**	1,864,633	3,039,912
Investing Activities			
Property additions and dry hole costs	**(2,316,372)**	(1,978,598)	(2,179,011)
Acquisition of ethanol plants [1]	**(40,000)**	(10,000)	–
Proceeds from sale of property, plant and equipment	**2,189**	1,616	361,961
Expenditures for major repairs	**(98,939)**	(30,253)	(57,604)
Purchase of investment securities [2]	**(2,388,720)**	(2,531,515)	(1,043,473)
Proceeds from maturity of investment securities [2]	**2,551,187**	2,172,830	623,133
Other investing activities – net	**(38,157)**	(34,050)	(21,256)
Investing activities of discontinued operations			
Sales proceeds	–	78,908	–
Other	–	(845)	(6,949)
Net cash required by investing activities	**(2,328,812)**	(2,331,907)	(2,323,199)
Financing Activities			
Additions to long-term debt	–	243,500	–
Reductions of long-term debt	**(332,038)**	–	(487,612)
Reductions of nonrecourse debt of a subsidiary	**(82,000)**	(2,572)	(5,235)
Proceeds from exercise of stock options and employee stock purchase plans	**42,995**	12,746	29,687
Excess tax benefits related to exercise of stock options	**11,672**	4,143	20,288
Cash dividends paid	**(201,405)**	(190,788)	(166,501)
Withholding tax on stock-based incentive awards	**(5,170)**	–	–
Net cash provided (required) by financing activities	**(565,946)**	67,029	(609,373)
Effect of exchange rate changes on cash and cash equivalents	**881**	35,279	(114,937)
Net increase (decrease) in cash and cash equivalents	**234,681**	(364,966)	(7,597)
Cash and cash equivalents at January 1	**301,144**	666,110	673,707
Cash and cash equivalents at December 31	**$ 535,825**	301,144	666,110

[1] Excludes nonrecourse seller financing of $82 million related to the Company's acquisition of the Hankinson, North Dakota, ethanol plant in 2009.
[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-8.

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

Years Ended December 31 *(Thousands of dollars)*	**2010**	2009	2008
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	**–**	–	–
Common Stock – par $1.00, authorized 450,000,000 shares at December 31, 2010, 2009 and 2008, issued 193,293,526 shares at December 31, 2010, 191,797,600 shares at December 31, 2009 and 191,248,941 shares at December 31, 2008			
Balance at beginning of year	**$ 191,798**	191,249	189,973
Exercise of stock options	**1,496**	549	1,276
Balance at end of year	**193,294**	191,798	191,249
Capital in Excess of Par Value			
Balance at beginning of year	**680,509**	631,859	547,185
Exercise of stock options, including income tax benefits	**54,887**	17,244	45,839
Restricted stock transactions and other	**(9,688)**	2,473	7,089
Stock-based compensation	**40,842**	27,976	30,811
Sale of stock under employee stock purchase plans	**1,212**	957	935
Balance at end of year	**767,762**	680,509	631,859
Retained Earnings			
Balance at beginning of year	**6,204,316**	5,557,483	3,983,998
Net income for the year	**798,081**	837,621	1,739,986
Cash dividends – $1.05 per share in 2010, $1.00 per share in 2009 and $0.875 per share in 2008	**(201,405)**	(190,788)	(166,501)
Balance at end of year	**6,800,992**	6,204,316	5,557,483
Accumulated Other Comprehensive Income (Loss)			
Balance at beginning of year	**287,187**	(87,697)	351,765
Foreign currency translation gains (losses), net of income taxes	**165,940**	375,951	(383,021)
Retirement and postretirement benefit plan adjustments, net of income taxes	**(3,699)**	(1,067)	(56,441)
Balance at end of year	**449,428**	287,187	(87,697)
Treasury Stock			
Balance at beginning of year	**(17,784)**	(13,949)	(6,747)
Sale of stock under employee stock purchase plans	**1,295**	1,604	515
Awarded restricted stock, net of forfeitures	**4,305**	–	–
Cancellation of performance-based restricted stock and forfeitures	**258**	(5,439)	(7,717)
Balance at end of year – 457,518 shares of Common Stock in 2010, 682,222 shares in 2009 and 535,135 shares in 2008	**(11,926)**	(17,784)	(13,949)
Total Stockholders' Equity	**$8,199,550**	7,346,026	6,278,945

See notes to consolidated financial statements, page F-8.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(Thousands of dollars)*	**2010**	2009	2008
Net income	**$798,081**	837,621	1,739,986
Other comprehensive income (loss), net of tax			
Net gain (loss) from foreign currency translation	**165,940**	375,951	(383,021)
Retirement and postretirement benefit plan adjustments	**(3,699)**	(1,067)	(56,441)
Other comprehensive income (loss)	**162,241**	374,884	(439,462)
Comprehensive Income	**$960,322**	1,212,505	1,300,524

See notes to consolidated financial statements, page F-8.

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, owns two petroleum refineries and two ethanol production facilities in the United States and one refinery in the United Kingdom. Murphy markets petroleum products under various brand names and to unbranded wholesale customers in the United States and United Kingdom. In 2010, the Company announced that it intends to sell its three refineries and U.K. marketing assets in 2011.

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

REVENUE RECOGNITION – Revenues from sales of crude oil, natural gas and refined petroleum products are recorded when deliveries have occurred and legal ownership of the commodity transfers to the customer. Refined products sold at retail are recorded when the customer takes delivery at the pump. Merchandise revenues are recorded at the point of sale. Revenues from the production of oil and natural gas properties in which Murphy shares an undivided interest with other producers are recognized based on the actual volumes sold by the Company during the period. Gas imbalances occur when the Company's actual sales differ from its entitlement under existing working interests. The Company records a liability for gas imbalances when it has sold more than its working interest of gas production and the estimated remaining reserves make it doubtful that partners can recoup their share of production from the field. At December 31, 2010 and 2009, 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, 2010, the Company owned Canadian government securities with maturities greater than 90 days at date of acquisition that had a carrying value of $616,558,000.

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 can not 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 common natural gas processing facilities are depreciated primarily using the composite straight-line method with depreciable lives ranging from 14 to 25 years. Gasoline stations and other properties are depreciated over 3 to 20 years by individual unit on the straight-line method. Gains and losses on asset disposals or retirements are included in income as a separate component of revenues.

Turnarounds for major processing units are scheduled at four to five year intervals at the Company's three refineries. 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 the Company's refineries and Syncrude will vary 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 include 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. 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 2010 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, 2010. Should a future assessment indicate that goodwill is not fully recoverable, an impairment charge to write down the carrying value of goodwill would be required.

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

INCOME TAXES – The Company accounts for income taxes using the asset and liability method. Under this method, income taxes are provided for amounts currently payable and for amounts deferred as tax assets and liabilities based on differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities. Deferred income taxes are measured using the enacted tax rates that are assumed will be in effect when the differences reverse. Petroleum revenue taxes are provided using the estimated effective tax rate over the life of applicable U.K. properties. The accounting rules for income tax uncertainties permit recognition of income tax benefits only when they are more likely than not to be realized. The Company includes potential penalties and interest for uncertain income tax positions in income tax expense.

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

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

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

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

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

New Accounting Principles Adopted

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

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

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

The Company adopted new accounting guidance for noncontrolling interests in consolidated financial statements effective January 1, 2009. This guidance was applied prospectively, except for presentation and disclosure requirements which are applied retrospectively. This guidance required noncontrolling interests to be reclassified as equity, and consolidated net income and comprehensive income shall include the respective results attributable to noncontrolling interests. The adoption of this guidance did not have a significant effect on the Company's consolidated financial statements.

The Company adopted new accounting guidance covering business combinations effective January 1, 2009. The new guidance established principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquired business. It also established how to recognize and measure goodwill acquired in the business combination or a gain from a bargain purchase, if applicable. This guidance impacts the recognition and measurement of assets and liabilities in business combinations that occur beginning in 2009. Assets and liabilities that arose from business combinations that occurred prior to 2009 are not affected by this guidance. The adoption of this guidance did not have a significant effect on the Company's financial statements for the year ended December 31, 2009. The Company is unable to predict how the application of this guidance will affect its financial statements in future periods.

The Company adopted new accounting guidance which addressed disclosures about derivative instruments and hedging activities in January 2009. This guidance expanded required disclosures regarding derivative instruments to include qualitative information about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments, and disclosures about credit-risk related contingent features in derivative agreements. See Note L for further disclosures.

In 2009, the Company adopted new accounting guidance for determining whether instruments granted in share-based payment transactions are participating securities. This guidance specified that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings per share (EPS) calculation under the two-class method, and also required that all prior-period EPS calculations be adjusted retrospectively. The adoption of this guidance did not have a significant impact on the Company's prior-period EPS calculations.

The Company adopted new accounting guidance addressing certain equity method investment accounting considerations in January 2009. The guidance, which has been applied prospectively, addressed how to initially measure contingent consideration for an equity method investment, how to recognize other-than-temporary impairments of an equity method investment, and how an equity method investor is to account for a share issuance by an investee. The adoption of this guidance did not have a significant impact on the Company's consolidated financial statements.

The Company adopted new accounting guidance addressing subsequent events effective June 30, 2009. The guidance clarified the accounting for and disclosure of subsequent events that occur after the balance sheet date through the date of issuance of the applicable financial statements. The adoption of this guidance did not have a significant effect on the Company's consolidated financial statements.

The FASB's Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles guidance became effective for interim and annual periods ended after September 15, 2009, and it recognized the FASB Accounting Standards Codification as the single source of authoritative nongovernment U.S. generally accepted accounting principles. The codification superseded all existing accounting standards documents issued by the FASB, and established that all other accounting literature not included in the codification is considered nonauthoritative. Although the codification did not change U.S. generally accepted accounting principles, it did reorganize the principles into accounting topics using a consistent structure. The codification also includes relevant U.S. Securities and Exchange Commission guidance following the same topical structure. Subsequent to adoption of this statement, all references to U.S. generally accepted accounting principles use the new topical guidelines established with the codification. Otherwise, this new standard did not have a material impact on the Company's consolidated financial statements.

The FASB has provided additional guidance regarding disclosures about postretirement benefit plan assets, including how asset investment allocation decisions are made, the fair value of each major category of plan assets, and how fair value is determined for each major asset category. This guidance was effective for the Company as of December 31, 2009. Upon adoption, no comparative disclosures were required for earlier years presented. See Note K for these disclosures.

In December 2008, the U.S. Securities and Exchange Commission (SEC) adopted revisions to oil and natural gas reserves reporting requirements which became effective for the Company at year-end 2009. The primary changes to reserves reporting included:

- A revised definition of proved reserves, including the use of unweighted average oil and natural gas prices in effect at the beginning of each month during the year to compute such reserves,
- Expanding the definition of oil and gas producing activities to include non-traditional and unconventional resources, which includes the Company's Canadian synthetic oil operations at Syncrude,
- Allowing companies to voluntarily disclose probable and possible reserves in SEC filings,
- Amending required proved reserve disclosures to include separate amounts for synthetic oil and gas,
- Expanded disclosures of proved undeveloped reserves, including discussion of such proved undeveloped reserves five years old or more, and
- Disclosure of the qualifications of the chief technical person who oversees the Company's overall reserve process.

The Company utilized this new guidance at December 31, 2010 and 2009 to determine its proved reserves and to develop associated disclosures. The Company chose not to provide voluntary disclosures of probable and possible reserves in this Form 10-K. In January 2010, the FASB issued guidance that aligned its oil and gas reporting requirements and effective date with the SEC's guidance described above.

Recent Accounting and Reporting Rules

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

Note C – Discontinued Operations

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

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

The following table reflects the results of operations, including the gain on sale, from the Ecuador properties sold in 2009.

(Thousands of dollars)	2009	2008
Revenues	$125,654	80,209
Income before income tax expense, including a gain on disposal of $117,557 in 2009	109,865	188
Income tax expense	12,761	4,951

Note D – Acquisitions

In August 2010, a wholly-owned subsidiary of the Company purchased an unfinished ethanol production facility in Hereford, Texas, for $40,000,000. The Company expects the construction of the facility to be completed and in operation by the end of the first quarter of 2011. The Company has allocated the purchase price for the Hereford facility as of acquisition date based on the estimated fair value of the assets acquired as presented in the following table.

(Thousands of dollars)	
Land and land improvements	$ 2,379
Buildings and improvements	639
Machinery and transportation equipment	36,982
Total purchase price	$40,000

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

(Thousands of dollars)	
Inventory	$ 2,469
Land and land improvements	11,833
Buildings and improvements	9,819
Machinery and transportation equipment	67,879
Total purchase price	$92,000

Note E – Property, Plant and Equipment

	December 31, 2010		December 31, 2009	
(Thousands of dollars)	**Cost**	**Net**	Cost	Net
Exploration and production[1]	**$12,506,579**	**7,898,417[2]**	10,258,126	6,834,178[2]
Refining	**2,266,883**	**1,301,128**	1,900,551	1,048,067
Marketing	**1,527,340**	**1,108,282**	1,518,349	1,120,494
Corporate and other	**108,041**	**60,020**	102,888	62,349
	$16,408,843	**10,367,847**	13,779,914	9,065,088
[1] Includes mineral rights as follows:	**$ 779,036**	**432,051**	576,543	326,382

[2] Includes 17,067 in 2010 and $11,773 in 2009 related to administrative assets and support equipment.

In January 2008, the Company sold its interest in Berkana Energy Corporation and recorded a pretax gain of $41,950,000 ($40,161,000 after-tax). In May 2008, the Company sold its interest in the Lloydminster area properties in Western Canada for a pretax gain of $90,451,000 ($67,236,000 after-tax).

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, 2010, 2009 and 2008, the Company had total capitalized drilling costs pending the determination of proved reserves of $497,765,000, $369,862,000, and $310,118,000, respectively. The following table reflects the net changes in capitalized exploratory well costs during the three-year period ended December 31, 2010.

(Thousands of dollars)	**2010**	2009	2008
Beginning balance at January 1	**$369,862**	310,118	272,155
Additions to capitalized exploratory well costs pending the determination of proved reserves	**137,403**	119,995	44,832
Reclassifications to proved properties based on the determination of proved reserves	**–**	(60,251)	(6,869)
Capitalized exploratory well costs charged to expense or sold	**(9,500)**	–	–
Ending balance at December 31	**$497,765**	369,862	310,118

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 have been capitalized since the completion of drilling.

(Thousands of dollars)	**2010**			2009			2008		
	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	**$135,494**	**15**	**4**	$117,618	10	6	$ 48,424	4	4
One to two years	**115,418**	**10**	**4**	49,628	4	4	8,870	7	–
Two to three years	**42,571**	**3**	**3**	8,870	5	–	101,151	18	4
Three years or more	**204,282**	**31**	**4**	193,746	27	4	151,673	14	4
	$497,765	**59**	**15**	$369,862	46	14	$ 310,118	43	12

Of the $362,271,000 of exploratory well costs capitalized more than one year at December 31, 2010, $235,418,000 is in Malaysia, $104,694,000 is in the U.S., $15,078,000 is in Republic of the Congo and $7,081,000 is in Canada. In Malaysia either further appraisal or development drilling is planned and/or development studies/plans are in various stages of completion. In the U.S. further drilling is anticipated and development plans are being formulated. In Republic of the Congo further appraised drilling is planned. In Canada a continuing drilling and development program is underway.

In July 2010, the Company announced that its Board of Directors had approved plans to exit the U.S. refining and U.K. refining and marketing businesses. These operations, which have been placed for sale, are included within the U.S. manufacturing and U.K. refining and marketing segments presented in Note U. The Company currently anticipates the sale of these operations to be completed in 2011. The Company expects that the results of these operations will be presented as discontinued operations in future periods when the criteria for held for sale under U.S. generally accepted accounting principles have been met.

Note F – Financing Arrangements

At December 31, 2010, the Company had a $1,905,000,000 committed credit facility with a major banking consortium that matures in June 2012. Between June 2011 and June 2012, the capacity of the committed facility is reduced to $1,827,500,000. At December 31, 2010, the Company had borrowed $340,000,000 under this committed facility. Borrowings under this facility bear interest at prime or varying cost of fund options. Facility fees are due at varying rates on the commitment. At December 31, 2010, the Company had no borrowings under uncommitted credit lines that amount to approximately $430,000,000. If necessary, the Company could borrow funds under all or certain of these uncommitted lines with various financial institutions in future periods. The Company has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities through September 2012.

Note G – Long-term Debt

	December 31	
(Thousands of dollars)	**2010**	2009
Notes payable		
6.375% notes, due 2012, net of unamortized discount of $154 at December 31, 2010	**$349,846**	349,731
7.05% notes, due 2029, net of unamortized discount of $1,709 at December 31, 2010	**248,291**	248,199
Notes payable to banks, 0.7375% at December 31, 2010	**340,000**	672,000
Other, 6%, due through 2028	**1,254**	1,291
Total notes payable	**939,391**	1,271,221
Nonrecourse debt of a subsidiary		
Loan payable to seller on ethanol plant, 5.0%, due in 2014	–	82,000
Total debt including current maturities	**939,391**	1,353,221
Current maturities	**(41)**	(38)
Total long-term debt	**$939,350**	1,353,183

Future maturities are: $41,000 in 2011, $689,889,000 in 2012, $46,000 in 2013, $48,000 in 2014, $51,000 in 2015 and $249,316,000 thereafter.

During 2010, the Company repaid nonrecourse debt used in 2009 to acquire an ethanol production facility in Hankinson, North Dakota.

Note H – Asset Retirement Obligations

The majority of the asset retirement obligations (ARO) recognized by the Company at December 31, 2010 and 2009 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 did not record 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 2010 and 2009 is shown in the following table.

(Thousands of dollars)	**2010**	2009
Balance at beginning of year	**$476,938**	435,589
Accretion expense	**31,858**	26,154
Liabilities incurred	**59,605**	42,578
Revision of previous estimates	**14,170**	(609)
Liabilities settled	**(36,506)**	(48,694)
Changes due to translation of foreign currencies	**9,183**	21,920
Balance at end of year	**$555,248**	476,938

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

Note I – Income Taxes

The components of income from continuing operations before income taxes for each of the three years ended December 31, 2010 and income tax expense attributable thereto were as follows.

(Thousands of dollars)	**2010**	2009	2008
Income from continuing operations before income taxes			
United States	**$ 214,109**	302,765	476,882
Foreign	**1,200,122**	974,408	2,341,483
	$1,414,231	1,277,173	2,818,365
Income tax expense			
Federal – Current	**$ 104,798**	114,037	134,759
Deferred	**(30,044)**	1,005	40,328
	74,754	115,042	175,087
State	**16,892**	9,496	16,714
Foreign – Current	**347,746**	318,619	689,407
Deferred	**176,758**	93,499	192,408
	524,504	412,118	881,815
Total	**$ 616,150**	536,656	1,073,616

Income tax benefits attributable to employee stock option transactions of $15,896,000 in 2010, $6,035,000 in 2009 and $23,964,000 in 2008 were included in Capital in Excess of Par Value in the Consolidated Balance Sheets.

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

(Thousands of dollars)	**2010**	2009	2008
Income tax expense based on the U.S. statutory tax rate	**$494,981**	447,011	986,428
Foreign income subject to foreign taxes at a rate different than the U.S. statutory rate	**56,367**	33,395	19,823
State income taxes, net of federal benefit	**10,979**	6,172	10,864
Increase in deferred tax asset valuation allowance related to foreign exploration expenditures	**47,128**	34,431	31,535
Other, net	**6,695**	15,647	24,966
Total	**$616,150**	536,656	1,073,616

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2010 and 2009 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	**2010**	2009
Deferred tax assets		
Property and leasehold costs	**$ 391,168**	344,735
Liabilities for dismantlements	**97,149**	91,546
Postretirement and other employee benefits	**137,709**	118,044
Foreign tax credit carryforwards	**47,725**	46,308
Other deferred tax assets	**47,511**	129,517
Total gross deferred tax assets	**721,262**	730,150
Less valuation allowance	**(305,349)**	(290,168)
Net deferred tax assets	**415,913**	439,982
Deferred tax liabilities		
Property, plant and equipment	**(729,699)**	(575,955)
Accumulated depreciation, depletion and amortization	**(702,512)**	(668,006)
Deferred major repair costs	**(35,848)**	(18,525)
Other deferred tax liabilities	**(96,838)**	(181,234)
Total gross deferred tax liabilities	**(1,564,897)**	(1,443,720)
Net deferred tax liabilities	**$(1,148,984)**	(1,003,738)

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 2011 through 2019. The valuation allowance increased $15,181,000 in 2010, 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, 2010, undistributed earnings of the Company's subsidiaries considered indefinitely invested were approximately $4,835,000,000. 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 $442,823,000. 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 U.S.

Uncertain Income Tax Positions

The FASB's rules for accounting for income tax uncertainties clarify the criteria for recognizing uncertain income tax benefits and requires additional disclosures about uncertain tax positions. Under current rules the financial statement recognition of the benefit for a tax position is dependent upon the benefit being more likely than not to be sustainable upon audit by the applicable taxing authority. If this threshold is met, the tax benefit is then measured and recognized at the largest amount that is greater than 50 percent likely of being realized upon ultimate settlement. Liabilities associated with uncertain income tax positions are included in Deferred Credits and Other Liabilities in the Consolidated Balance Sheet. A reconciliation of the beginning and ending amount of the consolidated liability for unrecognized income tax benefits during the years ended December 31, 2010 and 2009 follows.

(Thousands of dollars)	**2010**	2009
Balance at January 1	**$25,978**	20,765
Additions for tax positions related to current year	**1,225**	12,833
Additions for tax positions related to prior years	–	800
Settlements with tax authorities	–	(3,012)
Settlements due to lapse of time	**(4,007)**	(5,428)
Changes due to translation of foreign currencies	–	20
Balance at December 31	**$23,196**	25,978

All additions or reductions to the above liability, other than translation of foreign currencies, 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, 2010 and 2009 for interest and penalties of $1,010,000 and $967,000, respectively, associated with uncertain tax positions. Income tax expense for the years ended December 31, 2010, 2009 and 2008 included (charges)/benefits for interest and penalties of $(43,000), $1,763,000 and $1,185,000, 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 2011 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 2011.

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, 2010, the earliest years remaining open for audit and/or settlement in our major taxing jurisdictions are as follows: United States – 2007; Canada – 2006; United Kingdom – 2009; and Malaysia – 2006.

Note J – Incentive Plans

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

The 2007 Annual Incentive Plan (2007 Annual Plan) authorizes the Executive Compensation Committee (the Committee) to establish specific performance goals associated with annual cash awards that may be earned by officers, executives and other key employees. Cash awards under the 2007 Annual Plan are determined based on the Company's actual financial and operating results as measured against the performance goals established by the Committee. The 2007 Long-Term Incentive Plan (2007 Long-Term Plan) authorizes the Committee to make grants of the Company's Common Stock to employees. These grants may be in the form of stock options (nonqualified or incentive), stock appreciation rights (SAR), restricted stock, restricted stock units, performance units, performance shares, dividend equivalents and other stock-based incentives. The 2007 Long-Term Plan expires in 2017. A total of 6,700,000 shares are issuable during the life of the 2007 Long-Term Plan, with annual grants limited to 1% of Common shares outstanding; allowed shares not granted may be granted in future years. At December 31, 2010, approximately 6,080,000 shares remained available for issuance under the 2007 Long-Term Plan. The Company also has a Stock Plan for Non-Employee Directors (Directors Plan) that permits the issuance of restricted stock, restricted stock units and stock options or a combination thereof to the Company's Non-Employee Directors.

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

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

(Thousands of dollars)	**2010**	2009	2008
Compensation charged against income before income tax benefit	**$41,992**	28,618	25,656
Related income tax benefit recognized in income	**12,169**	7,860	8,628

As of December 31, 2010, there was $47,067,000 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, 2010, 2009 and 2008 was $42,995,000, $12,746,000 and $29,687,000, respectively. Total income tax benefits realized from tax deductions related to stock option exercises under share-based payment arrangements were $15,896,000, $6,035,000 and $23,964,000 for the years ended December 31, 2010, 2009 and 2008, respectively.

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

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

	2010	2009	2008
Fair value per option grant	**$18.75**	$15.15	$17.69
Assumptions			
Dividend yield	**1.80%**	1.40%	1.20%
Expected volatility	**43.00%**	41.00%	27.00%
Risk-free interest rate	**2.52%**	1.95%	2.58%
Expected life	**5.25 yrs.**	5.25 yrs.	4.75 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, 2007	5,801,510	$31.65
Granted at FMV	932,500	72.75
Exercised	(1,255,450)	20.56
Forfeited	(79,500)	60.40
Outstanding at December 31, 2008	5,399,060	40.90
Granted at FMV	1,057,000	43.95
Exercised	(560,500)	19.58
Forfeited	(464,000)	60.65
Outstanding at December 31, 2009	5,431,560	42.01
Granted at FMV	**1,605,628**	**52.85**
Exercised	**(1,580,950)**	**29.04**
Forfeited	**(153,854)**	**53.33**
Outstanding at December 31, 2010	**5,302,384**	**48.83**
Exercisable at December 31, 2008	3,375,810	$28.46
Exercisable at December 31, 2009	3,506,310	34.86
Exercisable at December 31, 2010	**2,499,610**	**45.07**

Additional information about stock options outstanding at December 31, 2010 is shown below.

	Options Outstanding			Options Exercisable		
Range of Exercise Prices per Option	No. of Options	Avg. Life in Years	Aggregate Intrinsic Value	No. of Options	Avg. Life in Years	Aggregate Intrinsic Value
$19.43 to $23.58	746,050	1.7	$ 40,149,000	746,050	1.7	$40,149,000
$30.30 to $45.23	1,290,060	4.0	39,763,000	344,560	0.9	10,830,000
$51.07 to $72.75	3,266,274	4.5	56,496,000	1,409,000	2.9	22,716,000
	5,302,384	4.0	$136,408,000	2,499,610	2.3	$73,695,000

The total intrinsic value of options exercised during 2010, 2009 and 2008 was $49,929,000, $17,932,000, and $71,405,000, respectively. Intrinsic value is the excess of the market price of stock at date of exercise over the exercise price received by the Company upon exercise. Aggregate intrinsic value is nil when the exercise price of the stock option exceeds the market price of the Company's Common stock.

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

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

(Number of shares or share units)	**2010**	2009	2008
Balance at beginning of year	**872,027**	806,822	798,497
Granted	**449,100**	375,050	328,000
Forfeited	**(45,084)**	(309,845)	(319,675)
Awarded	**(252,551)**	–	–
Balance at end of year	**1,023,492**	872,027	806,822

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 2010, 2009 and 2008 are presented in the following table.

	2010	2009	2008
Fair value per share at grant date	**\$42.38 – \$50.95**	\$41.18 – \$44.94	\$52.70 – \$62.53
Assumptions			
Expected volatility	**51.00%**	48.00%	29.00%
Risk-free interest rate	**1.41%**	1.37%	2.08%
Stock beta	**1.008**	0.973	0.885
Expected life	**3.00 yrs.**	3.00 yrs.	3.00 yrs.

TIME-LAPSE RESTRICTED STOCK AND RESTRICTED STOCK UNITS – Restricted stock and restricted stock units (RSU) have been granted to the Company's Non-Employee Directors under the Directors Plan. These awards vest on the third anniversary of the date of grant. In addition, the Committee awarded 60,000 time-lapse RSU to an officer during 2008. The fair value of these awards was estimated based on the fair market value of the Company's stock on the date of grant, which was \$52.49 per share in 2010, \$43.95 per share in 2009 and \$72.75 per share in 2008. Changes in time-lapse restricted stock and restricted stock units outstanding for each of the last three years are presented in the following table.

(Number of shares or share units)	**2010**	2009	2008
Balance at beginning of year	**164,695**	132,819	68,289
Granted	**43,370**	50,290	84,930
Expired	**(29,475)**	(18,414)	(20,400)
Forfeited	**(12,417)**	–	–
Balance at end of year	**166,173**	164,695	132,819

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 44,361 shares at an average price of \$51.97 per share in 2010, 51,271 shares at \$44.73 per share in 2009, and 20,715 shares at \$73.94 per share in 2008. At December 31, 2010, 355,934 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 \$357,000 in 2010, \$623,000 in 2009 and \$401,000 in 2008. The fair value per share issued under the ESPP was approximately \$7.51, \$11.47 and \$13.03 for the years ended December 31, 2010, 2009 and 2008, respectively.

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

CASH AWARDS – The Committee also administers the Company's incentive compensation plans, which provide for annual or periodic cash awards to officers, directors and key employees. These cash awards are generally determinable based on the Company achieving specific financial and/or operational objectives. Compensation expense of $25,171,000, $23,073,000 and $23,793,000 was recorded in 2010, 2009 and 2008, respectively, for these plans.

Note K – Employee and Retiree Benefit Plans

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

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

The tables that follow provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets for the years ended December 31, 2010 and 2009 and a statement of the funded status as of December 31, 2010 and 2009.

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	**2010**	2009	**2010**	2009
Change in benefit obligation				
Obligation at January 1	**$ 521,471**	441,697	**101,750**	87,318
Service cost	**20,706**	17,052	**4,133**	3,121
Interest cost	**30,144**	28,767	**6,211**	5,688
Plan amendments	**–**	612	**–**	–
Participant contributions	**33**	35	**956**	894
Actuarial loss	**30,544**	44,140	**14,646**	9,643
Medicare Part D subsidy	**–**	–	**528**	500
Exchange rate changes	**(1,357)**	11,311	**22**	–
Benefits paid	**(26,241)**	(24,561)	**(5,367)**	(5,820)
Special termination benefits	**–**	1,867	**–**	–
Curtailments	**–**	551	**–**	406
Obligation at December 31	**575,300**	521,471	**122,879**	101,750
Change in plan assets				
Fair value of plan assets at January 1	**375,947**	278,083	**–**	–
Actual return on plan assets	**46,792**	61,406	**–**	–
Employer contributions	**20,651**	50,772	**3,883**	4,426
Participant contributions	**33**	35	**956**	894
Medicare Part D subsidy	**–**	–	**528**	500
Exchange rate changes	**(422)**	10,598	**–**	–
Benefits paid	**(26,241)**	(24,561)	**(5,367)**	(5,820)
Other	**(488)**	(386)	**–**	–
Fair value of plan assets at December 31	**416,272**	375,947	**–**	–
Funded status and amounts recognized in the Consolidated Balance Sheets at December 31				
Deferred charges and other assets	**14,191**	13,895	**–**	–
Other accrued liabilities	**(3,378)**	(2,429)	**(5,223)**	–
Deferred credits and other liabilities	**(169,841)**	(156,990)	**(117,656)**	(101,750)
Funded status and net plan liability recognized at December 31	**$(159,028)**	(145,524)	**(122,879)**	(101,750)

At December 31, 2010, 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 loss	**$(153,873)**	**(52,190)**
Prior service (cost) credit	**(7,053)**	**1,975**
Transitional asset (liability)	**2,057**	**(24)**
	$(158,869)	**(50,239)**

Amounts included in AOCI at December 31, 2010 that are expected to be amortized into net periodic benefit expense during 2011 are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
Net loss	**$(10,745)**	**(3,113)**
Prior service (cost) credit	**(1,339)**	**263**
Transitional asset (liability)	**514**	**(8)**
	$(11,570)	**(2,858)**

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)	**2010**	2009	**2010**	2009	**2010**	2009
Funded qualified plans where accumulated benefit obligation exceeds fair value of plan assets	**$478,234**	436,208	**431,668**	382,672	**383,683**	346,187
Unfunded nonqualified and directors' plans where accumulated benefit obligation exceeds fair value of plan assets	**78,667**	69,398	**69,104**	52,308	**–**	–
Unfunded other postretirement plans	**122,879**	101,750	**122,879**	101,750	**–**	–

The table that follows provides the components of net periodic benefit expense for each of the three years ended December 31, 2010.

	Pension Benefits			Other Postretirement Benefits		
(Thousands of dollars)	**2010**	2009	2008	**2010**	2009	2008
Service cost	**$ 20,706**	17,052	17,928	**4,133**	3,121	2,708
Interest cost	**30,144**	28,767	27,667	**6,211**	5,688	5,087
Expected return on plan assets	**(24,199)**	(20,375)	(23,131)	**–**	–	–
Amortization of prior service cost	**1,558**	1,635	1,693	**(263)**	(263)	(264)
Amortization of transitional asset (liability)	**(514)**	(466)	(499)	**8**	–	–
Recognized actuarial loss	**12,257**	10,305	5,119	**2,790**	1,551	1,639
	39,952	36,918	28,777	**12,879**	10,097	9,170
Termination benefits expense	**–**	1,867	–	**–**	–	–
Curtailment expense	**–**	575	–	**–**	397	–
Net periodic benefit expense	**$ 39,952**	39,360	28,777	**12,879**	10,494	9,170

The increase in net periodic benefit expense in 2009 compared to prior years was mostly attributable to the decline in value of pension plan assets during 2008, plus termination and curtailment expenses related to an early retirement offer to certain U.S. employees during 2009.

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

(Thousands of dollars)	Pension Benefits 2010	Pension Benefits 2009	Other Postretirement Benefits 2010	Other Postretirement Benefits 2009
Benefit obligation at December 31	**$133,751**	121,664	**430**	–
Fair value of plan assets at December 31	**126,075**	107,982	**–**	–
Net plan liabilities recognized	**7,676**	13,682	**430**	–
Net periodic benefit expense	**9,784**	8,058	**60**	–

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2010 and 2009 and net periodic benefit expense for the years 2010 and 2009.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	December 31		December 31		Year		Year	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009
Discount rate	**5.66%**	5.97%	**5.66%**	5.90%	**5.88%**	6.49%	**5.90%**	6.75%
Expected return on plan assets	**6.56%**	6.60%	**–**	–	**6.56%**	6.60%	**–**	–
Rate of compensation increase	**4.19%**	4.14%	**–**	–	**4.19%**	4.30%	**–**	–

The discount rates used for purposes of determining the plan obligations and expense are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate which is the basis for selecting the discount 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
2011	$ 27,042	6,021
2012	28,423	6,459
2013	29,704	6,906
2014	31,397	7,322
2015	32,448	7,701
2016-2020	186,400	47,171

For purposes of measuring postretirement benefit obligations at December 31, 2010, the future annual rates of increase in the cost of health care were assumed to be 8.2% for 2011 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, 2010	$ 1,847	(1,464)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 2010	18,419	(14,981)

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

The Company provides a health care benefit plan to eligible U.S. employees and most U.S. retired employees. The new law did not significantly affect the Company's consolidated financial statements as of December 31, 2010 and for the year 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 three 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 75%, fixed income securities may range from 25% to 65%, 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 reminder split between North American, European, Japanese and other Pacific Basin securities. A minimum of 95% of the fixed income allocation is to be invested in U.K. securities with up to 5% in international or high yield bonds. Tolerance ranges are specified in the Document within the general equity/bond allocation guidelines. Asset performance is compared to a benchmark return based on the allocation guidelines and is targeted to outperform the benchmark by 0.75% per annum over a rolling three-year period. Small working cash balances are permitted to facilitate daily management of payments and receipts within the plan. The trustees routinely review the investment performance of the plan.

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

The weighted average asset allocation for the Company's funded pension benefit plans at December 31, 2010 and 2009 are presented in the following table.

	December 31,	
	2010	2009
Equity securities	**62.7%**	60.5%
Fixed income securities	**36.2**	38.7
Cash equivalents	**1.1**	0.8
	100.0%	100.0%

The Company's weighted average expected return on plan assets was 6.56% in 2010 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 6.56% expected return was based on an expected average future equity securities return of 8.36% and a fixed income securities return of 4.62% and is net of average expected investment expenses of 0.28%. Over the last 10 years, the return on funded retirement plan assets has averaged 4.74%.

At December 31, 2010 and 2009, the fair value measurements of retirement plan assets within the fair value hierarchy were as follows:

		Fair Value Measurements Using		
(Thousands of dollars)	**Fair Value at December 31, 2010**	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	**$ 79,550**	79,550	–	–
U.S. small/midcap	**17,324**	17,324	–	–
U.S. long/short equity fund	**14,205**	–	14,205	–
International commingled trust fund	**61,531**	–	61,531	–
Emerging market commingled equity fund	**7,131**	–	7,131	–
Fixed income securities:				
U.S. fixed income	**81,989**	–	81,989	–
International commingled trust fund	**19,833**	–	19,833	–
Emerging market mutual fund	**7,045**	–	7,045	–
Cash and equivalents	**1,589**	1,589	–	–
Total Domestic Plans	**290,197**	98,463	191,734	–
Foreign Plans				
Equity securities funds	**58,353**	–	58,353	–
Fixed income securities funds	**31,948**	–	31,948	–
Diversified pooled fund	**32,590**	–	32,590	–
Cash and equivalents	**3,184**	3,184	–	–
Total Foreign Plans	**126,075**	3,184	122,891	–
Total	**$416,272**	101,647	314,625	–

(Thousands of dollars)	Fair Value at December 31, 2009	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	$ 90,387	90,387	–	–
U.S. small/midcap	13,752	13,752	–	–
International commingled trust fund	53,552	–	53,552	–
Fixed income securities:				
U.S. fixed income	89,891	–	89,891	–
International commingled trust fund	18,271	–	18,271	–
Cash and equivalents	2,112	2,112	–	–
Total Domestic Plans	267,965	106,251	161,714	–
Foreign Plans				
Equity securities funds	50,279	–	50,279	–
Fixed income securities funds	26,900	–	26,900	–
Diversified pooled fund	29,760	–	29,760	–
Cash and equivalents	1,043	1,043	–	–
Total Foreign Plans	107,982	1,043	106,939	–
Total	$375,947	107,294	268,653	–

The definition of levels within the fair value hierarchy in the above table 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 2010, the Company made contributions of $12,834,000 to its domestic defined benefit pension plans, $7,817,000 to its foreign defined benefit pension plans, $3,838,000 to its domestic postretirement benefits plan and $45,000 to its foreign postretirement benefits plan. The Company currently expects during 2011 to make contributions of $24,646,000 to its domestic defined benefit pension plans, $14,669,000 to its foreign defined benefit pension plans, $5,970,000 to its domestic postretirement benefits plan and $52,000 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. 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 $11,467,000 in 2010, $11,617,000 in 2009 and $6,215,000 in 2008.

Note L – Financial Instruments and Risk Management

DERIVATIVE INSTRUMENTS – Murphy makes limited use of derivative instruments to manage certain risks related to commodity prices, interest rates and foreign currency exchange rates. The use of derivative instruments for risk management is covered by operating policies and is closely monitored by the Company's senior management. The Company does not hold any derivatives for speculative purposes and it does not use derivatives with leveraged or complex features. Derivative instruments are traded primarily with creditworthy major financial institutions or over national exchanges such as the New York Mercantile Exchange (NYMEX).

- *Commodity Purchase Price Risks* – The Company is subject to commodity price risk related to crude oil and intermediate feedstocks it holds in inventory at its refineries. Short-term derivative instruments were outstanding at December 31, 2010 to manage the 2011 purchase price of 118,000 barrels of crude oil at the Company's Superior, Wisconsin refinery. The total pretax charge from marking these contracts to market at year-end 2010 was $335,000. There were no open crude oil purchase contracts at December 31, 2009, but $2,296,000 was receivable from a third party at that date on a matured contract.

  The Company is also subject to commodity price risk related to corn that it will purchase in the future for feedstock at its ethanol production facility in Hankinson, North Dakota. At December 31, 2010, the Company had open physical delivery fixed-price purchase commitment contracts for approximately 7.0 million bushels of corn for processing at its ethanol plant. The Company also had outstanding derivative contracts to sell 7.5 million bushels of fixed-priced quantities and buy them back at future prices in effect on the expected date of delivery under the purchase commitment contracts. The total pretax benefit from marking to market these contracts at year-end 2010 was $750,000.

  The total net receivable from third parties on open and matured commodity contracts was $124,000 at December 31, 2010.

- *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, 2010 and 2009, short-term derivative instruments were outstanding to manage the risk of approximately $38,000,000 and $36,000,000, respectively, of U.S. dollar accounts receivable balances associated with the Company's Canadian crude oil operations. Also short-term derivative instruments were outstanding at December 31, 2010 and 2009 to manage the risk of approximately $366,000,000 and $100,000,000 equivalent, respectively, of ringgit denominated income tax liability balances in the Company's Malaysian operations. The impacts on consolidated income from continuing operations before taxes from marking to market these derivative contracts as of December 31, 2010 and 2009 were gains of $7,261,000 and $340,000, respectively.

At December 31, 2010 and 2009, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

	December 31, 2010				December 31, 2009			
	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
Commodity derivative contracts	Accounts Receivable	**$ 750**	Accounts Payable	**$626**	Accounts Receivable	$2,296	–	$ –
Foreign exchange derivative contracts	Accounts Receivable	**7,261**	–	–	Accounts Receivable	340	–	–

For the years ended December 31, 2010 and 2009, the gains and losses recognized in the consolidated statement of income for derivative instruments not designated as hedging instruments are presented in the following table.

	Year Ended December 31, 2010		Year Ended December 31, 2009	
(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
Commodity derivative contracts	Crude Oil and Product Purchases	**$ (7,577)**	Crude Oil and Product Purchases	$(26,241)
Foreign exchange derivative contracts	Interest and Other Income (Loss)	**34,215**	Interest and Other Income (Loss)	5,052
		$26,638		$(21,189)

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

Note M – Earnings per Share

The following table reconciles the weighted-average shares outstanding for computation of basic and diluted income per Common share for each of the three years ended December 31, 2010. No difference existed between net income used in computing basic and diluted income per Common share for these years.

(Weighted-average shares outstanding)	**2010**	2009	2008
Basic method	**191,830,357**	190,767,077	189,608,846
Dilutive stock options	**1,327,457**	1,701,373	2,524,826
Diluted method	**193,157,814**	192,468,450	192,133,672

Outstanding options to purchase shares of Common Stock were not included in the computation of diluted earnings per share in 2010 through 2008 because the incremental shares from assumed conversion were antidilutive. These included 2,220,567 shares at a weighted average share price of $58.78 in 2010, 1,793,905 shares at a weighted average share price of $56.25 in 2009 and 924,000 shares at a weighted average share price of $72.745 in 2008.

Note N – Other Financial Information

INVENTORIES – Inventories accounted for under the LIFO method totaled $345,449,000 and $334,768,000 at December 31, 2010 and 2009, respectively, and these amounts were $735,091,000 and $551,184,000 less than such inventories would have been valued using the FIFO method.

ACCOUNTS RECEIVABLE – In 2009, the Company recorded pretax income, and a related accounts receivable, of $244,418,000 plus $42,000,000 of associated interest thereon, for an anticipated recovery of federal royalties paid in previous years on certain oil and gas properties in the Gulf of Mexico. These amounts were collected in 2010.

ACCUMULATED OTHER COMPREHENSIVE INCOME – At December 31, 2010 and 2009, the components of Accumulated Other Comprehensive Income were as follows.

(Thousands of dollars)	**2010**	2009
Foreign currency translation gains, net of tax	**$ 587,408**	421,468
Retirement and postretirement plan liability adjustments, net of tax	**(137,980)**	(134,281)
Balance at end of year	**$ 449,428**	287,187

At December 31, 2010, components of the net foreign currency translation gains of $587,408,000 were gains (losses) of $548,724,000 for Canadian dollars, $42,968,000 for pounds sterling and $(4,284,000) 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 $(63,861,000) in 2010, $48,429,000 in 2009 and $(105,620,000) in 2008.

CASH FLOW DISCLOSURES – Cash income taxes paid were $585,759,000, $501,506,000, and $380,602,000 in 2010, 2009 and 2008, respectively. Interest paid, net of amounts capitalized, was $35,452,000, $21,017,000 and $43,715,000 in 2010, 2009 and 2008, respectively.

Noncash operating working capital (increased) decreased during each of the three years ended December 31, 2010 as follows.

(Thousands of dollars)	**2010**	2009	2008
Accounts receivable	**$ (4,363)**	(402,481)	386,605
Inventories	**(28,231)**	(114,569)	22,474
Prepaid expenses	**14,567**	7,209	(12,959)
Deferred income tax assets	**(80,073)**	14,772	56,451
Accounts payable and accrued liabilities	**766,067**	365,257	(701,450)
Current income tax liabilities	**(28,401)**	(64,878)	342,589
Net (increase) decrease in noncash operating working capital	**$639,566**	(194,690)	93,710

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 Company carries certain assets and liabilities at fair value in its Consolidated Balance Sheet. The fair value measurements for these assets and liabilities at December 31, 2010 and 2009 are presented in the following table.

		Fair Value Measurements at Reporting Date Using		
(Thousands of dollars)	**Fair Value at December 31, 2010**	Quoted Prices in Active Markets for Identical Assets (Liabilities) (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets				
Foreign exchange derivative assets	**$ 7,261**	–	7,261	–
Commodity derivative assets	**750**	–	750	–
Total	**8,011**	–	8,011	–
Liabilities				
Nonqualified employee savings plan	**(7,672)**	(7,672)	–	–
Commodity derivative liabilities	**(626)**	–	(626)	–
Total	**(8,298)**	(7,672)	(626)	–

		Fair Value Measurements at Reporting Date Using		
(Thousands of dollars)	Fair Value at December 31, 2009	Quoted Prices in Active Markets for Identical Assets (Liabilities) (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets				
Foreign exchange derivative assets	$ 340	–	340	–
Commodity derivative assets	2,296	–	2,296	–
Total	2,636	–	2,636	–
Liabilities				
Nonqualified employee savings plan	(5,691)	(5,691)	–	–

At the balance sheet date the fair value of commodity derivatives contracts for crude oil was determined based on market quotes for WTI crude and the fair value of commodity derivative contracts for corn was determined based on market quotes for No. 2 yellow corn. The fair value of derivative contracts for foreign currency exchange was based on quotes from active brokers in the respective markets. The change in fair value of commodity derivatives is recorded in Crude Oil and Product Purchases and the change in fair value of foreign currency exchange derivatives is recorded in Interest and Other Income (Loss). The nonqualified employee savings plan is an unfunded savings plan through which the participants seek a return via phantom investments in equity securities and/or mutual funds. The fair value of this savings plan liability was based on quoted prices for these equity securities and mutual funds. The income effect of the changes in the fair value of nonqualified employee savings plan is recorded in Selling and General Expense in the Consolidated Statement of Income. The carrying value of the Company's Cash and Cash Equivalents, Accounts Receivable and Accounts Payable approximates fair value.

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

The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2010 and 2009. 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,			
	2010		2009	
(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	**$ 616,558**	**617,372**	779,025	779,234
Current and long-term debt	**(939,391)**	**(1,064,225)**	(1,353,221)	(1,400,539)

Note P – Hurricane and Insurance Related Matters

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

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

The Company also settled with an insurance consortium in 2009 for its claims related to a crude oil spill that occurred at the Meraux refinery after Hurricane Katrina. The settlement led to pretax income of $6,500,000 in the Consolidated Statement of Income for 2009, with $4,500,000 related to the insurance claim included in Sales and Other Operating Revenues for the North American Refining and Marketing segment and $2,000,000 of associated interest income included in Interest and Other Income for Corporate activities. During 2010, the Company received $3,000,000 to settle its claim against one insurer for legal and other professional costs associated with the insurance coverage negotiation process. This amount was recorded as a reduction of Selling and General Expense to reflect recovery of incurred legal fees associated with this matter.

Note Q – Commitments

In 2010, the Company entered into forward sales contracts to mitigate the price risk for a portion of its 2011 natural gas sales volumes at the Tupper field in Western Canada. The contract calls for natural gas deliveries of approximately 34 million cubic feet per day during 2011 at an average price of Cdn$6.27 per thousand cubic feet at the AECO "C" sales point. The contract has been accounted for as a normal sale for accounting purposes.

The Company leases land, gasoline stations, and production and other facilities under operating leases. The most significant operating leases are associated with floating, production, storage and offloading facilities at the Kikeh and Azurite oil fields, a production facility at the Thunder Hawk field, certain motor fuel stations in the U.K and land under a portion of gasoline stations in the U.S. During the next five years, expected future rental payments under all operating leases are approximately $166,012,000 in 2011, $152,646,000 in 2012, $136,033,000 in 2013, $125,518,000 in 2014 and $114,056,000 in 2015. Rental expense for noncancellable operating leases, including contingent payments when applicable, was $178,410,000 in 2010, $124,693,000 in 2009 and $88,890,000 in 2008.

The Company has entered into contracts to hire various drilling rigs and associated equipment for periods beyond December 31, 2010. These rigs will primarily be utilized for drilling operations in the Gulf of Mexico, onshore U.S. and Canada, and offshore Malaysia and Republic of the Congo. Future commitments under these contracts, all of which expire by 2012, total approximately $394,398,000. 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.

To assure a long-term supply of hydrogen at its Meraux, Louisiana refinery, the Company has contracted to purchase up to 35 million standard cubic feet of hydrogen per day at market prices through 2021. The contract requires the payment of a base facility charge for use of the facility. Future required minimum annual payments for base facility charges for the next five years are $6,754,000 in 2011, $6,923,000 in 2012, $7,096,000 in 2013, $7,274,000 in 2014, and $7,456,000 in 2015. Base facility charges and hydrogen costs incurred in 2010, 2009 and 2008 totaled $26,826,000, $26,888,000 and $45,396,000, respectively.

The Company has operating, production handling and transportation agreements providing for processing, production handling and transportation services for hydrocarbon production from certain fields in the Gulf of Mexico and Western Canada. These agreements require minimum monthly or annual payments for processing and/or transportation charges through 2018. Future required minimum monthly payments for the next five years are $17,413,000 in 2011, $22,255,000 in 2012, $14,537,000 in 2013, $17,185,000 in 2014 and $17,543,000 in 2015. 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 $10,337,000 in 2010, $11,860,000 in 2009 and $9,276,000 in 2008.

Additionally, the Company has a Reserved Capacity Service Agreement providing for the availability of needed crude oil storage capacity for certain oil fields through 2020. Under the agreement, the Company must make specified minimum payments monthly. Future required minimum annual payments are approximately $3,500,000 in 2011 through 2015. In addition, the Company is required to pay additional amounts depending on actual crude oil quantities stored under the agreement. Total payments under the agreement were $3,202,000 in 2010, $2,743,000 in 2009 and $3,703,000 in 2008.

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 four payments have been made through January 2010. The Company recorded a discounted liability of $38,700,000 in 2006 for this unconditional commitment. The liability was discounted at the Company's 10-year borrowing rate and the discounted liability increases for accretion monthly with a corresponding charge to Selling and General Expenses in the Consolidated Statement of Income. Total accretion cost included in Selling and General Expense was $1,534,000 in 2010, $1,739,000 in 2009 and $1,931,000 in 2008.

Commitments for capital expenditures were approximately $1,300,757,000 at December 31, 2010, including $678,015,000 for field development and future work commitments in Malaysia, and $118,335,000 for costs to develop deepwater Gulf of Mexico fields.

Note R – Contingencies

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

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

The Company currently owns or leases, and has in the past owned or leased, properties at which hazardous substances have been or are being handled. Although the Company has used operating and disposal practices that were standard in the industry at the time, hazardous substances may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes were not under Murphy's control. Under existing laws the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. While some of these historical properties are in various stages of negotiation, investigation, and/or cleanup, the Company is investigating the extent of any such liability and the availability of applicable defenses and 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, 2010.

The U.S. Environmental Protection Agency (EPA) currently considers the Company to be a Potentially Responsible Party (PRP) at one Superfund site. The potential total cost to all parties to perform necessary remedial work at this site may be substantial. However, based on current negotiations and available information, the Company believes that it is a de minimis party as to ultimate responsibility at the Superfund site. Accordingly, the Company has not recorded a liability for remedial costs at the Superfund site at December 31, 2010. The Company could be required to bear a pro rata share of costs attributable to nonparticipating PRPs or could be assigned additional responsibility for remediation at this site or other Superfund sites. The Company believes that its share of the ultimate costs to clean-up this Superfund site will be immaterial and will not have a material adverse effect on its net income, financial condition or liquidity in a future period.

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

LEGAL MATTERS – Litigation arising out of a June 10, 2003 fire in the Residual Oil Supercritical Extraction (ROSE) unit at the Company's Meraux, Louisiana refinery was settled in July 2009 and memorialized via a filing in the U.S. District Court for the Eastern District of Louisiana on July 24, 2009. An arbitral tribunal heard the Company's claim for indemnity from one of its insurers, AEGIS, in September 2009 and a decision is pending. The Company believes that insurance coverage applies for this matter. The Company continues to believe that the ultimate resolution of the June 2003 ROSE fire litigation, including associated insurance coverage issues, will not have a material adverse effect on its net income, financial condition or liquidity in a future period.

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, 2010, the Company had contingent liabilities of $7,798,000 under a financial guarantee described in the following paragraph and $223,424,000 on outstanding letters of credit. The Company has not accrued a liability in its balance sheet related to these contingent liabilities and letters of credit because it is believed that the likelihood of having these drawn is remote.

The Company owns a 3.2% interest in the Louisiana Offshore Oil Port (LOOP) that it accounts for at cost. At year-end 2010, LOOP had $243,690,000 of outstanding bonds, which mature in varying amounts between 2014 and 2027 and which are secured by a Throughput and Deficiency Agreement (T&D). The Company is obligated to ship crude oil in quantities sufficient for LOOP to pay certain of its expenses and obligations, including long-term debt secured by the T&D, or to make cash payments for which the Company will receive credit for future throughput. No other collateral secures the investee's obligation or the Company's guarantee. As of December 31, 2010, it is not probable that the Company will be required to make payments under the guarantee; therefore, no liability has been recorded for the Company's obligation under the T&D agreement. The Company continues to monitor conditions that are subject to guarantees to identify whether it is probable that a loss has occurred, and it would recognize any such losses under the guarantees should losses become probable.

Note S – Terra Nova Working Interest Redetermination

The joint agreement between the owners of the Terra Nova field, offshore Eastern Canada, required a one-time redetermination of working interests based on an analysis of reservoir quality among fault separated areas where varying ownership interests existed. Under the redetermination, which was essentially completed in 2010, the Company's working interest at Terra Nova will be reduced from its original 12.0% to 10.475% effective in January 2011. The Company made a cash payment to certain Terra Nova partners in January 2011 to equalize all partners' interest in the field since about December 2004 related to the Company's working interest reduction. The Company recorded expense of $18,582,000 in 2010 and $83,498,000 in 2009 based on the anticipated working interest reduction, with this amount reflected as Redetermination of Terra Nova Working Interest in the Consolidated Statement of Income.

Note T – Common Stock Issued and Outstanding

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2010 is shown below.

(Number of shares outstanding)	**2010**	2009	2008
At beginning of year	**191,115,378**	190,713,806	189,714,149
Stock options exercised	**1,495,926**	548,659	1,275,971
Employee stock purchase and thrift plans	**49,657**	61,575	19,755
Restricted stock awards, net of forfeitures	**175,047**	(208,662)	(299,334)
All other	**–**	–	3,265
At end of year	**192,836,008**	191,115,378	190,713,806

Note U – Business Segments

Murphy's reportable segments are organized into two major types of business activities, each subdivided into geographic areas of operations. The Company's exploration and production activity is subdivided into segments for the United States, Canada, Malaysia, the United Kingdom, Republic of the Congo and all other countries; each of these segments derives revenues primarily from the sale of crude oil and/or natural gas. The Company's refining and marketing segments are United States Manufacturing, United States Marketing and the United Kingdom and each derives revenue mainly from the sale of petroleum products and merchandise. United States Manufacturing operations include two refineries and an ethanol production facility. United States Marketing includes retail and wholesale fuel marketing operations. Transactions between these two U.S. downstream segments are recorded at agreed transfer prices that are essentially market and eliminations have been made as necessary within the consolidated financial statements. The Company sells gasoline in the United States at retail stations built primarily at Walmart Supercenters. The Company's management evaluates segment performance based on income from operations, excluding interest income and interest expense. Intersegment transfers of crude oil, natural gas and petroleum products are at market prices and intersegment services are recorded at cost.

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 $2,034,105,000, $2,069,323,000 and $2,140,338,000 for the years 2010, 2009 and 2008, respectively, that were collected by the Company and remitted to various government entities were excluded from revenues and costs and expenses.

Segment Information

(Millions of dollars)	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Other	Total
	Exploration and Production						
Year ended December 31, 2010							
Segment income (loss)	**$ 72.7**	**213.8**	**659.4**	**30.5**	**(77.2)**	**(92.3)**	**806.9**
Revenues from external customers	**659.9**	**780.2**	**1,837.9**	**133.6**	**155.7**	**3.9**	**3,571.2**
Intersegment revenues	–	**118.9**	–	–	–	–	**118.9**
Interest income	–	–	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–	–	–
Income tax expense (benefit)	**30.0**	**79.1**	**414.1**	**32.6**	**20.6**	**.5**	**576.9**
Significant noncash charges (credits)							
Depreciation, depletion, amortization	**281.1**	**225.5**	**379.0**	**22.4**	**95.5**	**1.5**	**1,005.0**
Accretion of asset retirement obligations	**6.9**	**11.2**	**9.8**	**2.3**	**.4**	**.5**	**31.1**
Amortization of undeveloped leases	**68.5**	**33.7**	–	–	–	**5.8**	**108.0**
Deferred and noncurrent income taxes	**(48.6)**	**34.5**	**145.5**	**(11.4)**	**(.9)**	–	**119.1**
Additions to property, plant, equipment	**369.4**	**804.5**	**468.0**	**(4.7)**	**163.5**	**49.8**	**1,850.5**
Total assets at year-end	**1,651.3**	**3,242.6**	**3,333.1**	**187.9**	**678.9**	**88.9**	**9,182.7**
Year ended December 31, 2009							
Segment income (loss)	$ 178.0	64.8	561.9	12.6	(20.6)	(104.9)	691.8
Revenues from external customers	708.6	635.2	1,526.4	61.6	16.5	2.4	2,950.7
Intersegment revenues	–	85.3	–	–	–	–	85.3
Interest income	–	–	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–	–	–
Income tax expense (benefit)	88.4	21.0	354.1	11.9	1.3	(.6)	476.1
Significant noncash charges (credits)							
Depreciation, depletion, amortization	246.5	199.9	304.1	12.4	11.5	1.4	775.8
Accretion of asset retirement obligations	6.8	8.6	7.8	1.6	.1	.6	25.5
Amortization of undeveloped leases	34.7	44.1	–	–	–	4.4	83.2
Impairment of long-lived assets	5.2	–	–	–	–	–	5.2
Deferred and noncurrent income taxes	(4.6)	(7.2)	77.6	(.9)	–	(.1)	64.8
Additions to property, plant, equipment	336.8	330.1	739.0	17.2	194.9	7.6	1,625.6
Total assets at year-end	1,679.7	2,507.8	3,249.6	209.0	516.7	33.5	8,196.3
Year ended December 31, 2008							
Segment income (loss)	$ 156.6	588.7	865.3	73.8	(1.1)	(80.5)	1,602.8
Revenues from external customers	529.1	1,210.0	2,000.6	215.8	–	1.8	3,957.3
Intersegment revenues	–	166.5	–	.2	–	–	166.7
Interest income	–	–	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–	–	–
Income tax expense (benefit)	85.8	244.7	552.9	72.9	–	–	956.3
Significant noncash charges (credits)							
Depreciation, depletion, amortization	110.0	139.4	248.4	28.9	.2	.9	527.8
Accretion of asset retirement obligations	6.2	8.3	5.9	2.4	–	.7	23.5
Amortization of undeveloped leases	25.2	85.9	–	–	.8	.1	112.0
Deferred and noncurrent income taxes	25.6	(.5)	176.2	3.0	–	(3.2)	201.1
Additions to property, plant, equipment	366.4	470.7	664.1	31.7	150.4	12.7	1,696.0
Total assets at year-end	1,458.3	2,017.0	2,675.4	210.8	413.9	36.8	6,812.2

Geographic Information

(Millions of dollars)	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Other	Total
	Certain Long-Lived Assets at December 31						
2010	**$3,178.8**	**3,028.8**	**2,807.0**	**706.3**	**579.4**	**74.3**	**10,374.6**
2009	2,907.2	2,324.6	2,714.9	704.7	399.9	20.5	9,071.8
2008	2,671.1	1,880.6	2,277.0	591.6	231.6	83.5	7,735.4

Segment Information (Continued)

(Millions of dollars)	Refining and Marketing – United States – Manufacturing	Refining and Marketing – United States – Marketing	Refining and Marketing – United Kingdom	Refining and Marketing – Total	Corporate and Other	Discontinued Operations	Consolidated
Year ended December 31, 2010							
Segment income (loss)	**$ 28.4**	**155.4**	**(34.7)**	**149.1**	**(157.9)**	**–**	**798.1**
Revenues from external customers	**845.8**	**16,080.0**	**2,905.0**	**19,830.8**	**(56.9)**	**–**	**23,345.1**
Intersegment revenues	**3,906.6**	**–**	**–**	**3,906.6**	**–**	**–**	**4,025.5**
Interest income	**–**	**–**	**–**	**–**	**6.9**	**–**	**6.9**
Interest expense, net of capitalization	**–**	**–**	**–**	**–**	**34.7**	**–**	**34.7**
Income tax expense (benefit)	**11.8**	**97.0**	**(22.3)**	**86.5**	**(47.2)**	**–**	**616.2**
Significant noncash charges (credits)							
Depreciation, depletion, amortization	**56.2**	**54.2**	**41.4**	**151.8**	**8.0**	**–**	**1,164.8**
Accretion of asset retirement obligations	**–**	**.8**	**–**	**.8**	**–**	**–**	**31.9**
Amortization of undeveloped leases	**–**	**–**	**–**	**–**	**–**	**–**	**108.0**
Deferred and noncurrent income taxes	**12.1**	**1.2**	**3.2**	**16.5**	**7.8**	**–**	**143.4**
Additions to property, plant, equipment	**164.4**	**173.9**	**69.1**	**407.4**	**5.9**	**–**	**2,263.8**
Total assets at year-end	**1,456.8**	**1,539.8**	**1,113.6**	**4,110.2**	**940.3**	**–**	**14,233.2**
Year ended December 31, 2009							
Segment income (loss)	$ 31.2	61.0	(20.5)	71.7	(23.0)	97.1	837.6
Revenues from external customers	558.8	12,674.8	2,725.9	15,959.5	102.2	–	19,012.4
Intersegment revenues	2,957.0	–	–	2,957.0	–	–	3,042.3
Interest income	–	–	–	–	51.7	–	51.7
Interest expense, net of capitalization	–		–	–	24.4	–	24.4
Income tax expense (benefit)	17.5	39.9	(1.0)	56.4	4.2	–	536.7
Significant noncash charges (credits)							
Depreciation, depletion, amortization	51.9	51.6	33.8	137.3	6.0	–	919.1
Accretion of asset retirement obligations	–	.7	–	.7	–	–	26.2
Amortization of undeveloped leases	–	–	–	–	–	–	83.2
Impairment of long-lived assets	–	–	–	–	–	–	5.2
Deferred and noncurrent income taxes	4.9	6.5	15.9	27.3	5.0	–	97.1
Additions to property, plant, equipment	202.5	71.6	101.8	375.9	23.0	.8	2,025.3
Total assets at year-end	1,117.7	1,372.9	939.8	3,430.4	1,129.7	–	12,756.4
Year ended December 31, 2008							
Segment income (loss)	$ (39.8)	267.7	85.9	313.8	(171.8)	(4.8)	1,740.0
Revenues from external customers	660.7	18,266.3	4,639.1	23,566.1	(91.1)	–	27,432.3
Intersegment revenues	4,236.8	–	–	4,236.8	–	–	4,403.5
Interest income	–	–	–	–	40.8	–	40.8
Interest expense, net of capitalization	–	–	–	–	42.2	–	42.2
Income tax expense (benefit)	(23.5)	158.1	38.1	172.7	(55.4)	–	1,073.6
Significant noncash charges (credits)							
Depreciation, depletion, amortization	49.1	48.1	36.9	134.1	5.4	–	667.3
Accretion of asset retirement obligations	–	1.0	–	1.0	–	–	24.5
Amortization of undeveloped leases	–	–	–	–	–	–	112.0
Deferred and noncurrent income taxes	15.9	.5	5.3	21.7	10.1	–	232.9
Additions to property, plant, equipment	82.4	258.9	84.9	426.2	3.2	–	2,125.4
Total assets at year-end	981.7	1,332.8	805.6	3,120.1	1,142.2	74.6	11,149.1

Geographic Information

Revenues from External Customers for the Year

(Millions of dollars)	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Other	Total
2010	**$17,562.0**	**3,018.7**	**809.3**	**1,793.8**	**156.5**	**4.8**	**23,245.1**
2009	13,973.1	2,838.7	652.5	1,526.4	16.5	5.2	19,012.4
2008	19,352.5	4,855.1	1,222.3	2,000.6	–	1.8	27,432.3

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

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

Due to new SEC proved reserve definitions beginning at year-end 2009, Murphy has included synthetic crude oil from its 5% interest in the Syncrude project in Alberta, Canada in its proved oil reserves for the first time. 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% - 90%. Overall, it takes approximately two metric tons of oil sand to produce one barrel of synthetic crude oil. All synthetic oil volumes reported as reserves in this filing are the final synthetic crude oil product.

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

Oil and natural gas reserves in Malaysia are associated with production sharing contracts for Blocks SK 309/311 and K. Malaysia reserves include oil and gas to be received for both cost recovery and profit provisions under the contracts. Oil and natural gas reserves associated with the production sharing contracts in Malaysia totaled 98.4 million barrels and 434 billion cubic feet, respectively, at December 31, 2010. Approximately 85.9 billion cubic feet of natural gas proved reserves in Malaysia relate to the Kikeh field for which the Company expects to receive sale proceeds of approximately $0.23 per thousand cubic foot. Oil reserves attributable to a production sharing agreement in Republic of the Congo amounted to 10.1 million barrels at December 31, 2010.

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

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

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

Schedule 5 also presents the principal reasons for change in the standardized measure of discounted future net cash flows for each of the three years ended December 31, 2010.

Schedule 1 – Summary of Proved Oil Reserves Based on Year-End Prices for 2007 and 2008 and Average Prices for 2009 and 2010

	Total	Total – by product		United States	Canada		Malaysia	United Kingdom	Republic of the Congo	Ecuador
(Millions of barrels)	All Products	Oil	Synthetic Oil	Oil	Oil	Synthetic Oil	Oil	Oil	Oil	Oil
Proved developed and undeveloped reserves:										
December 31, 2007	178.2	178.2	–	31.2	38.2	–	82.6	18.8	–	7.4
Revisions of previous estimates	10.0	10.0	–	(1.5)	(1.9)	–	13.3	–	–	.1
Improved recovery	18.4	18.4	–	–	–	–	18.4	–	–	–
Extensions and discoveries	9.5	9.5	–	1.0	1.1	–	7.4	–	–	–
Production	(38.7)	(38.7)	–	(3.9)	(9.3)	–	(21.0)	(1.8)	–	(2.7)
Sales of properties	(3.8)	(3.8)	–	–	(3.8)	–	–	–	–	–
December 31, 2008	173.6	173.6	–	26.8	24.3	–	100.7	17.0	–	4.8
Synthetic reserves now presented as proved under SEC rules	131.6	–	131.6	–	–	131.6	–	–	–	–
Revisions of previous estimates	5.8	3.2	2.6	5.0	7.2	2.6	(4.9)	(4.1)	–	–
Improved recovery	31.0	31.0	–	–	–	–	31.0	–	–	–
Extensions and discoveries	23.9	23.9	–	.8	3.3	–	11.2	–	8.6	–
Production	(48.2)	(43.5)	(4.7)	(6.2)	(7.0)	(4.7)	(27.9)	(1.2)	(.7)	(.5)
Sales of properties	(4.3)	(4.3)	–	–	–	–	–	–	–	(4.3)
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**	**.4**	**4.3**	**–**
Improved recovery	**5.8**	**5.8**	**–**	**–**	**1.0**	**–**	**4.8**	**–**	**–**	**–**
Extensions and discoveries	**12.6**	**12.6**	**–**	**4.1**	**5.0**	**–**	**3.5**	**–**	**–**	**–**
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**	**–**
Proved developed reserves:										
December 31, 2008	122.5	122.5	–	16.7	23.1	–	63.4	14.5	–	4.8
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**	**–**
Proved undeveloped reserves:										
December 31, 2008	51.1	51.1	–	10.1	1.2	–	37.3	2.5	–	–
December 31, 2009	43.4	33.6	9.8	8.1	1.6	9.8	20.1	–	3.8	–
December 31, 2010	**59.7**	**49.6**	**10.1**	**10.8**	**4.2**	**10.1**	**31.9**	**–**	**2.7**	**–**

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.

Schedule 2 – Summary of Proved Natural Gas Reserves Based on Year-End Prices for 2007 and 2008 and Average Prices for 2009 and 2010

(Billions of cubic feet)	Total	United States	Canada	Malaysia	United Kingdom
Proved developed and undeveloped reserves:					
December 31, 2007	590.8	113.3	29.9	424.0	23.6
Revisions of previous estimates	(43.5)	1.1	.8	(45.4)	–
Improved recovery	1.9	–	–	1.9	–
Extensions and discoveries	82.1	.8	56.0	25.3	–
Production	(23.0)	(17.8)	(1.8)	(.6)	(2.8)
Sales of properties	(22.7)	–	(22.7)	–	–
December 31, 2008	585.6	97.4	62.2	405.2	20.8
Revisions of previous estimates	77.2	9.1	(.6)	59.4	9.3
Improved recovery	6.9	–	–	6.9	–
Extensions and discoveries	153.5	2.6	83.3	67.6	–
Production	(68.4)	(19.8)	(20.0)	(27.3)	(1.3)
Sales of properties	(.2)	–	(.2)	–	–
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)**	**–**	**–**	**(1.0)**	**–**
Extensions and discoveries	**220.5**	**14.3**	**194.2**	**12.0**	**–**
Purchases of properties	**24.0**	**–**	**24.0**	**–**	**–**
Production	**(130.2)**	**(19.4)**	**(31.2)**	**(77.6)**	**(2.0)**
December 31, 2010	**883.1**	**90.8**	**326.9**	**434.0**	**31.4**
Proved developed reserves:					
December 31, 2008	209.2	58.8	52.0	79.5	18.9
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**
Proved undeveloped reserves:					
December 31, 2008	376.4	38.6	10.2	325.7	1.9
December 31, 2009	353.0	16.1	35.0	301.9	–
December 31, 2010	**297.1**	**23.8**	**116.8**	**156.5**	**–**

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.

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

(Millions of dollars)	United States	Canada[1]	Malaysia	United Kingdom	Republic of the Congo	Ecuador[2]	Other	Total
Year Ended December 31, 2010								
Property acquisition costs								
Unproved	$129.8	78.6	–	–	–	–	34.4	242.8
Proved	–	22.0	–	–	–	–	–	22.0
Total acquisition costs	129.8	100.6	–	–	–	–	34.4	264.8
Exploration costs[3]	204.1	1.8	99.6	6.7	93.5	–	67.7	473.4
Development costs[3]	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)	–	14.3	15.2	35.5	–	26.5	90.1
Geophysical and other costs	37.1	1.8	5.4	1.0	21.0	–	27.8	94.1
Total charged to expense	35.7	1.8	19.7	16.2	56.5	–	54.3	184.2
Property additions	$396.5	821.6	476.6	6.0	169.3	–	49.8	1,919.8
Year Ended December 31, 2009								
Property acquisition costs								
Unproved	$ 82.4	31.0	–	–	–	–	4.7	118.1
Proved	–	–	–	–	–	–	–	–
Total acquisition costs	82.4	31.0	–	–	–	–	4.7	118.1
Exploration costs[3]	89.7	9.9	114.4	.1	19.1	–	79.4	312.6
Development costs[3]	197.2	321.4	695.9	15.1	187.5	.8	1.2	1,419.1
Total costs incurred	369.3	362.3	810.3	15.2	206.6	.8	85.3	1,849.8
Charged to expense								
Dry hole expense	11.3	–	55.0	–	13.9	–	45.1	125.3
Geophysical and other costs	16.2	10.0	.8	.2	(3.1)	–	32.6	56.7
Total charged to expense	27.5	10.0	55.8	.2	10.8	–	77.7	182.0
Property additions	$341.8	352.3	754.5	15.0	195.8	.8	7.6	1,667.8
Year Ended December 31, 2008								
Property acquisition costs								
Unproved	$125.7	20.6	–	–	–	–	9.7	156.0
Proved	–	–	–	–	–	–	–	–
Total acquisition costs	125.7	20.6	–	–	–	–	9.7	156.0
Exploration costs[3]	142.4	18.8	97.2	10.2	1.1	–	60.0	329.7
Development costs[3]	168.9	421.7	687.9	27.2	149.4	6.9	3.0	1,465.0
Total costs incurred	437.0	461.1	785.1	37.4	150.5	6.9	72.7	1,950.7
Charged to expense								
Dry hole expense	18.0	–	80.4	–	–	–	31.1	129.5
Geophysical and other costs	40.2	18.9	14.3	.5	.2	–	28.8	102.9
Total charged to expense	58.2	18.9	94.7	.5	.2	–	59.9	232.4
Property additions	$378.8	442.2	690.4	36.9	150.3	6.9	12.8	1,718.3

[1] Excludes property additions for the Company's 5% interest in synthetic oil operations in Canada of $35.6 million in 2008. With the SEC's rule change to include synthetic oil reserves as proved reserves, the Company has included synthetic oil property additions of $63.2 million in 2010 and $46.1 million in 2009.
[2] The Company sold its Ecuador operations on March 12, 2009.
[3] Includes non-cash asset retirement costs as follows:

2010								
Exploration costs	$ 3.4	–	–	–	–	–	–	3.4
Development costs	23.7	17.1	8.6	10.7	5.8	–	–	65.9
	$27.1	17.1	8.6	10.7	5.8	–	–	69.3
2009								
Exploration costs	$ 5.0	–	–	–	–	–	–	5.0
Development costs	–	22.2	15.5	(2.2)	.9	–	–	36.4
	$ 5.0	22.2	15.5	(2.2)	.9	–	–	41.4
2008								
Exploration costs	$ 6.1	–	–	–	–	–	–	6.1
Development costs	6.3	7.1	26.3	5.2	–	–	–	44.9
	$12.4	7.1	26.3	5.2	–	–	–	51.0

Schedule 4 – Results of Operations for Oil and Gas Producing Activities[1]

(Millions of dollars)	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Other	Subtotal	Synthetic Oil – Canada	Total
Year Ended December 31, 2010									
Revenues									
Crude oil and natural gas liquids									
Sales to unaffiliated enterprises	**$557.6**	**346.4**	**1,531.1**	**118.8**	**156.7**	–	**2,710.6**	**301.9**	**3,012.5**
Transfers to consolidated operations	–	**42.2**	–	–	–	–	**42.2**	**76.7**	**118.9**
Natural gas									
Sales to unaffiliated enterprises	**87.0**	**132.1**	**307.1**	**14.1**	–	–	**540.3**	–	**540.3**
Total oil and gas revenues	**644.6**	**520.7**	**1,838.2**	**132.9**	**156.7**	–	**3,293.1**	**378.6**	**3,671.7**
Other operating revenues	**15.3**	**(.2)**	**(.3)**	**.7**	**(1.0)**	**3.9**	**18.4**	–	**18.4**
Total revenues	**659.9**	**520.5**	**1,837.9**	**133.6**	**155.7**	**3.9**	**3,311.5**	**378.6**	**3,690.1**
Costs and expenses									
Production expenses	**131.7**	**97.5**	**355.0**	**26.9**	**62.0**	–	**673.1**	**206.4**	**879.5**
Exploration costs charged to expense	**35.7**	**1.9**	**19.8**	**16.2**	**56.4**	**54.3**	**184.3**	–	**184.3**
Undeveloped lease amortization	**68.5**	**33.7**	–	–	–	**5.8**	**108.0**	–	**108.0**
Depreciation, depletion and amortization	**281.1**	**180.3**	**379.0**	**22.4**	**95.5**	**1.5**	**959.8**	**45.2**	**1,005.0**
Accretion of asset retirement obligations	**6.9**	**4.8**	**9.8**	**2.3**	**.4**	**.5**	**24.7**	**6.4**	**31.1**
Terra Nova working interest redetermination	–	**18.6**	–	–	–	–	**18.6**	–	**18.6**
Selling and general expenses	**33.3**	**10.5**	**.8**	**2.7**	**(2.0)**	**33.6**	**78.9**	**.9**	**79.8**
Total costs and expenses	**557.2**	**347.3**	**764.4**	**70.5**	**212.3**	**95.7**	**2,047.4**	**258.9**	**2,306.3**
	102.7	**173.2**	**1,073.5**	**63.1**	**(56.6)**	**(91.8)**	**1,264.1**	**119.7**	**1,383.8**
Income tax expense	**30.0**	**44.6**	**414.1**	**32.6**	**20.6**	**.5**	**542.4**	**34.5**	**576.9**
Results of operations	**$ 72.7**	**128.6**	**659.4**	**30.5**	**(77.2)**	**(92.3)**	**721.7**	**85.2**	**806.9**
Year Ended December 31, 2009									
Revenues									
Crude oil and natural gas liquids									
Sales to unaffiliated enterprises	$374.8	310.7	1,478.4	54.7	24.5	–	2,243.1	258.1	2,501.2
Transfers to consolidated operations	–	54.9	–	–	–	–	54.9	30.4	85.3
Natural gas									
Sales to unaffiliated enterprises	80.6	68.6	45.4	6.4	–	–	201.0	–	201.0
Total oil and gas revenues	455.4	434.2	1,523.8	61.1	24.5	–	2,499.0	288.5	2,787.5
Other operating revenues[2]	253.2	(2.2)	2.6	.5	(8.0)	2.4	248.5	–	248.5
Total revenues	708.6	432.0	1,526.4	61.6	16.5	2.4	2,747.5	288.5	3,036.0
Costs and expenses									
Production expenses	101.2	97.9	248.2	19.9	15.4	–	482.6	171.9	654.5
Exploration costs charged to expense	27.5	10.0	55.8	.2	10.8	77.7	182.0	–	182.0
Undeveloped lease amortization	34.7	44.1	–	–	–	4.4	83.2	–	83.2
Depreciation, depletion and amortization	246.5	171.8	304.1	12.4	11.5	1.4	747.7	28.1	775.8
Accretion of asset retirement obligations	6.8	4.3	7.8	1.6	.1	.6	21.2	4.3	25.5
Impairment of long-lived assets	5.2	–	–	–	–	–	5.2	–	5.2
Terra Nova working interest redetermination	–	83.5	–	–	–	–	83.5	–	83.5
Selling and general expenses	20.3	18.0	(5.5)	3.0	(2.0)	23.8	57.6	.8	58.4
Total costs and expenses	442.2	429.6	610.4	37.1	35.8	107.9	1,663.0	205.1	1,868.1
	266.4	2.4	916.0	24.5	(19.3)	(105.5)	1,084.5	83.4	1,167.9
Income tax expense (benefits)	88.4	1.2	354.1	11.9	1.3	(.6)	456.3	19.8	476.1
Results of operations	$178.0	1.2	561.9	12.6	(20.6)	(104.9)	628.2	63.6	691.8

[1] Results exclude corporate overhead, interest and discontinued operations.

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

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

(Millions of dollars)	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Other	Subtotal	Synthetic Oil – Canada	Total
Year Ended December 31, 2008									
Revenues									
Crude oil and natural gas liquids									
Sales to unaffiliated enterprises	$374.0	697.5	1,985.6	189.2	–	–	3,246.3	371.4	3,617.7
Transfers to consolidated operations	–	78.3	–	.2	–	–	78.5	88.2	166.7
Natural gas									
Sales to unaffiliated enterprises	162.1	5.5	.1	25.8	–	–	193.5	–	193.5
Total oil and gas revenues	536.1	781.3	1,985.7	215.2	–	–	3,518.3	459.6	3,977.9
Other operating revenues[2]	(7.0)	133.1	14.9	.8	–	1.8	143.6	2.5	146.1
Total revenues	529.1	914.4	2,000.6	216.0	–	1.8	3,661.9	462.1	4,124.0
Costs and expenses									
Production expenses	67.0	88.6	234.4	32.9	–	–	422.9	188.6	611.5
Exploration costs charged to expense	58.2	18.9	94.7	.5	.1	60.0	232.4	–	232.4
Undeveloped lease amortization	25.2	85.9	–	–	.8	.1	112.0	–	112.0
Depreciation, depletion and amortization	110.0	111.1	248.4	28.9	.2	.9	499.5	28.3	527.8
Accretion of asset retirement obligations	6.2	4.4	5.9	2.4	–	.7	19.6	3.9	23.5
Selling and general expenses	20.1	12.6	(1.0)	4.6	–	20.6	56.9	.8	57.7
Total costs and expenses	286.7	321.5	582.4	69.3	1.1	82.3	1,343.3	221.6	1,564.9
	242.4	592.9	1,418.2	146.7	(1.1)	(80.5)	2,318.6	240.5	2,559.1
Income tax expense	85.8	169.1	552.9	72.9	–	–	880.7	75.6	956.3
Results of operations	$156.6	423.8	865.3	73.8	(1.1)	(80.5)	1,437.9	164.9	1,602.8

[1] Results exclude corporate overhead, interest and discontinued operations.
[2] Other operating revenues in Canada in 2008 primarily related to gains on sale of Berkana Energy and properties in the Lloydminster heavy oil area.

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

(Millions of dollars)	United States	Canada[1]	Malaysia	United Kingdom	Republic of the Congo	Ecuador[2]	Total
December 31, 2010							
Future cash inflows	**$2,472.8**	**13,440.2**	**8,118.9**	**1,005.1**	**758.9**	**–**	**25,795.9**
Future development costs	**(379.7)**	**(1,244.5)**	**(756.3)**	**(14.0)**	**(69.6)**	**–**	**(2,464.1)**
Future production and abandonment costs	**(631.3)**	**(6,923.3)**	**(2,379.0)**	**(305.6)**	**(330.7)**	**–**	**(10,569.9)**
Future income taxes	**(335.0)**	**(1,509.8)**	**(1,659.4)**	**(329.0)**	**(82.4)**	**–**	**(3,915.6)**
Future net cash flows	**1,126.8**	**3,762.6**	**3,324.2**	**356.5**	**276.2**	**–**	**8,846.3**
10% annual discount for estimated timing of cash flows	**(254.2)**	**(1,818.0)**	**(922.2)**	**(123.5)**	**(34.4)**	**–**	**(3,152.3)**
Standardized measure of discounted future net cash flows	**$ 872.6**	**1,944.6**	**2,402.0**	**233.0**	**241.8**	**–**	**5,694.0**
December 31, 2009							
Future cash inflows	$1,908.1	9,571.1	7,496.1	831.2	467.7	–	20,274.2
Future development costs	(245.7)	(191.3)	(726.3)	(9.7)	(99.7)	–	(1,272.7)
Future production and abandonment costs	(523.6)	(5,450.6)	(1,976.1)	(330.4)	(176.5)	–	(8,457.2)
Future income taxes	(264.8)	(952.3)	(1,531.3)	(250.2)	(83.2)	–	(3,081.8)
Future net cash flows	874.0	2,976.9	3,262.4	240.9	108.3	–	7,462.5
10% annual discount for estimated timing of cash flows	(174.8)	(1,521.4)	(838.0)	(64.7)	(7.2)	–	(2,606.1)
Standardized measure of discounted future net cash flows	$ 699.2	1,455.5	2,424.4	176.2	101.1	–	4,856.4
December 31, 2008							
Future cash inflows	$1,722.0	999.6	5,602.3	751.0	–	128.5	9,203.4
Future development costs	(330.0)	(26.3)	(924.8)	(133.3)	–	(4.8)	(1,419.2)
Future production and abandonment costs	(495.6)	(445.0)	(1,078.8)	(254.8)	–	(87.4)	(2,361.6)
Future income taxes	(217.9)	(157.0)	(1,336.8)	(201.4)	–	–	(1,913.1)
Future net cash flows	678.5	371.3	2,261.9	161.5	–	36.3	3,509.5
10% annual discount for estimated timing of cash flows	(146.1)	(62.2)	(572.3)	(59.6)	–	(4.1)	(844.3)
Standardized measure of discounted future net cash flows	$ 532.4	309.1	1,689.6	101.9	–	32.2	2,665.2

[1] Excludes discounted future net cash flows from synthetic oil of $378.9 million at December 31, 2008. With the SEC's change in the definition of proved reserves to include synthetic oil as proved reserves, the Company has included synthetic oil reserves in this table beginning in 2009.
[2] The Company sold its Ecuador operations on March 12, 2009.

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

(Millions of dollars)	**2010**	2009	2008
Inclusion of synthetic oil reserves beginning in 2009	**$ –**	378.9	–
Net changes in prices, production costs and development costs	**240.1**	675.1	(3,433.3)
Sales and transfers of oil and gas produced, net of production costs	**(2,792.2)**	(2,381.5)	(3,288.1)
Net change due to extensions and discoveries	**1,022.2**	1,976.2	825.4
Net change due to purchases and sales of proved reserves	**48.7**	(36.7)	(75.0)
Development costs incurred	**1,271.3**	1,344.1	1,245.0
Accretion of discount	**698.9**	422.1	798.5
Revisions of previous quantity estimates	**798.8**	267.8	164.0
Net change in income taxes	**(450.2)**	(454.8)	956.7
Net increase (decrease)	**837.6**	2,191.2	(2,806.8)
Standardized measure at January 1	**4,856.4**	2,665.2	5,472.0
Standardized measure at December 31	**$ 5,694.0**	4,856.4	2,665.2

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

(Millions of dollars)	United States	Canada	Malaysia	United Kingdom	Republic of the Congo	Other	Subtotal	Synthetic Oil – Canada	Total
December 31, 2010									
Unproved oil and gas properties	**$ 564.7**	**729.0**	**322.4**	**–**	**57.9**	**79.6**	**1,753.6**	**–**	**1,753.6**
Proved oil and gas properties	**1,869.1**	**2,861.1**	**3,596.0**	**526.1**	**657.0**	**3.3**	**9,512.6**	**1,171.6**	**10,684.2**
Gross capitalized costs	**2,433.8**	**3,590.1**	**3,918.4**	**526.1**	**714.9**	**82.9**	**11,266.2**	**1,171.6**	**12,437.8**
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	**(126.5)**	**(200.5)**	**–**	**–**	**(6.0)**	**(13.8)**	**(346.8)**	**–**	**(346.8)**
Proved oil and gas properties	**(1,074.6)**	**(1,258.4)**	**(1,115.3)**	**(347.9)**	**(129.8)**	**(3.3)**	**(3,929.3)**	**(280.3)**	**(4,209.6)**
Net capitalized costs	**$ 1,232.7**	**2,131.2**	**2,803.1**	**178.2**	**579.1**	**65.8**	**6,990.1**	**891.3**	**7,881.4**
December 31, 2009									
Unproved oil and gas properties	$ 427.9	467.8	254.5	9.5	21.3	19.7	1,200.7	–	1,200.7
Proved oil and gas properties	1,626.9	2,217.4	3,201.8	510.6	404.6	3.6	7,964.9	1,035.0	8,999.9
Gross capitalized costs	2,054.8	2,685.2	3,456.3	520.1	425.9	23.3	9,165.6	1,035.0	10,200.6
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	(78.8)	(157.3)	–	–	(6.1)	(8.0)	(250.2)	–	(250.2)
Proved oil and gas properties	(791.1)	(1,017.9)	(744.5)	(328.8)	(20.3)	(3.6)	(2,906.2)	(221.8)	(3,128.0)
Net capitalized costs	$ 1,184.9	1,510.0	2,711.8	191.3	399.5	11.7	6,009.2	813.2	6,822.4

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

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, 2010					
Sales and other operating revenues	**$5,228.7**	**5,592.3**	**6,072.4**	**6,507.7**	**23,401.1**
Income before income taxes	**286.1**	**445.0**	**360.0**	**323.1**	**1,414.2**
Net income	**148.9**	**272.3**	**202.8**	**174.1**	**798.1**
Net income per Common share					
Basic	**0.78**	**1.42**	**1.06**	**0.90**	**4.16**
Diluted	**0.77**	**1.41**	**1.05**	**0.90**	**4.13**
Cash dividend per Common share	**0.25**	**0.25**	**0.275**	**0.275**	**1.05**
Market price of Common Stock*					
High	**59.71**	**61.82**	**61.92**	**75.37**	**75.37**
Low	**50.13**	**49.55**	**48.44**	**61.01**	**48.44**
Year Ended December 31, 2009					
Sales and other operating revenues	$3,416.4	4,496.0	5,202.2	5,803.6	18,918.2
Income from continuing operations before income taxes	156.5	271.1	312.8	536.8	1,277.2
Income from continuing operations	71.2	160.9	188.9	319.5	740.5
Net income	171.1	158.8	188.9	318.8	837.6
Income from continuing operations per Common share					
Basic	0.37	0.84	0.99	1.67	3.88
Diluted	0.37	0.84	0.98	1.65	3.85
Net income per Common share					
Basic	0.90	0.83	0.99	1.67	4.39
Diluted	0.89	0.83	0.98	1.65	4.35
Cash dividend per Common share	0.25	0.25	0.25	0.25	1.00
Market price of Common Stock*					
High	51.79	60.49	61.79	64.66	64.66
Low	38.18	43.93	50.38	53.18	38.18

*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
2010					
Deducted from asset accounts:					
Allowance for doubtful accounts	**$ 7.8**	**.5**	**(.2)**	**(.1)**	**8.0**
Deferred tax asset valuation allowance	**290.2**	**15.1**	**–**	**–**	**305.3**
2009					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 7.3	.9	(.2)	(.2)	7.8
Deferred tax asset valuation allowance	266.8	23.4	–	–	290.2
2008					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 7.5	.1	(.2)	(.1)	7.3
Deferred tax asset valuation allowance	214.1	52.7	–	–	266.8

*Amounts primarily represent changes in foreign currency exchange rates.

GLOSSARY OF TERMS

3-D 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

feedstock
crude oil, natural gas liquids and other materials used as raw materials for making gasoline and other refined products by the Company's refineries

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
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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 in Transfer Agent and Registrar at left.

E-mail Address
murphyoil@murphyoilcorp.com

Web Site
www.murphyoilcorp.com
Murphy Oil's Web site 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's U.S. retail gasoline station locator

Annual Meeting
The annual meeting of the Company's shareholders will be held at 10:00 a.m. on May 11, 2011, 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
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

David M. Wood
President and Chief Executive Officer and Director and Member of the Executive Committee since January 2009. Mr. Wood served as Executive Vice President and President of Murphy Exploration & Production Company from January 2007 until December 2008, and President of Murphy Exploration & Production Company-International from March 2003 through December 2006.

Roger W. Jenkins
Executive Vice President since August 2009. Mr. Jenkins has served as President of Murphy Exploration & Production Company since January 2009, and prior to that was Senior Vice President, North America for this subsidiary from September 2007 to December 2008.

Thomas McKinlay
Executive Vice President, World Wide Downstream operations and President of Murphy Oil USA, Inc. since January 2011. Mr. McKinlay was Vice President, U.S. Manufacturing from August 2009 to January 2011.

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

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 1996 to January 2009.

Bill H. Stobaugh
Senior Vice President since February 2005. Mr. Stobaugh joined the Company as Vice President in 1995.

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

John W. Eckart
Vice President and Controller since January 2007. Mr. Eckart has been Controller since March 2000.

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

John A. Moore
Secretary, since March 2011. Mr. Moore was Senior Attorney from 2005 to February 2011.

MURPHY
OIL CORPORATION

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