MURPHY OIL CORP /DE
Form 10-Q
November 06, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark one)

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

For the quarterly period ended September 30, 2012

OR

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

For the transition period from to

Commission File Number 1-8590

MURPHY OIL CORPORATION

(Exact name of registrant as specified in its charter)

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

(870) 862-6411

(Registrant s telephone number, including area code)

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. x 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). x Yes ¨ No

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

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

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

Number of shares of Common Stock, $1.00 par value, outstanding at September 30, 2012 was **194,338,081.**

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MURPHY OIL CORPORATION

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PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED BALANCE SHEETS

(Thousands of dollars)

	(Unaudited) September 30, 2012	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 816,694	513,873
Canadian government securities with maturities greater than 90 days at the date of acquisition	491,604	532,093
Accounts receivable, less allowance for doubtful accounts of $7,856 in 2012 and $7,892 in 2011	1,639,428	1,554,184
Inventories, at lower of cost or market		
Crude oil	249,853	189,320
Finished products	302,308	254,880
Materials and supplies	277,037	222,438
Prepaid expenses	239,444	93,397
Deferred income taxes	63,547	87,486
Assets held for sale	22,057	0
Total current assets	4,101,972	3,447,671
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $7,631,197 in 2012 and $6,861,494 in 2011	12,111,918	10,475,149
Goodwill	43,470	41,863
Deferred charges and other assets	145,994	173,455
Assets held for sale	186,483	0
Total assets	$ 16,589,837	14,138,138
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 45	350,005
Accounts payable and accrued liabilities	2,918,657	2,273,139
Income taxes payable	255,970	201,784
Liabilities associated with assets held for sale	49,949	0
Total current liabilities	3,224,621	2,824,928
Long-term debt	1,184,580	249,553
Deferred income taxes	1,379,526	1,230,111
Asset retirement obligations	613,240	615,545
Deferred credits and other liabilities	444,025	439,604
Liabilities associated with assets held for sale	127,087	0
Stockholders equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued	0	0
Common Stock, par $1.00, authorized 450,000,000 shares, issued 194,452,935 shares in 2012 and 193,909,200 shares in 2011	194,453	193,909

Capital in excess of par value	860,314	817,974
Retained earnings	8,105,611	7,460,942
Accumulated other comprehensive income	459,374	310,420
Treasury stock, 114,854 shares of Common Stock in 2012 and 185,992 shares of Common Stock in 2011, at cost	(2,994)	(4,848)
Total stockholders equity	9,616,758	8,778,397
Total liabilities and stockholders equity	$ 16,589,837	14,138,138

See Notes to Consolidated Financial Statements, page 7.

The Exhibit Index is on page 35.

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Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF INCOME (unaudited)

(Thousands of dollars, except per share amounts)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011*	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011*
REVENUES				
Sales and other operating revenues	$ 7,130,629	7,194,393	21,231,317	20,781,506
Gain on sale of assets	(31)	60	94	23,192
Interest and other income (expense)	(8,321)	25,767	5,407	39,390
Total revenues	7,122,277	7,220,220	21,236,818	20,844,088
COSTS AND EXPENSES				
Crude oil and product purchases	5,667,359	5,727,873	16,813,044	16,633,221
Operating expenses	526,969	512,511	1,547,828	1,448,063
Exploration expenses, including undeveloped lease amortization	94,063	85,505	243,714	303,827
Selling and general expenses	85,509	72,858	261,287	218,337
Depreciation, depletion and amortization	330,253	271,270	972,663	783,531
Accretion of asset retirement obligations	10,005	8,638	29,052	26,162
Redetermination of Terra Nova working interest	0	0	0	(5,351)
Interest expense	12,941	17,329	36,278	41,648
Interest capitalized	(11,461)	(2,475)	(27,360)	(11,547)
Total costs and expenses	6,715,638	6,693,509	19,876,506	19,437,891
Income from continuing operations before income taxes	406,639	526,711	1,360,312	1,406,197
Income tax expense	177,728	179,401	558,657	558,773
Income from continuing operations	228,911	347,310	801,655	847,424
Income (loss) from discontinued operations, net of taxes	(2,230)	58,804	10,534	139,206
NET INCOME	$ 226,681	406,114	812,189	986,630
INCOME PER COMMON SHARE BASIC				
Income from continuing operations	$ 1.18	1.80	4.13	4.38
Income (loss) from discontinued operations	(0.01)	0.30	0.05	0.72
Net income	$ 1.17	2.10	4.18	5.10
INCOME PER COMMON SHARE DILUTED				
Income from continuing operations	$ 1.17	1.79	4.12	4.36
Income (loss) from discontinued operations	(0.01)	0.30	0.05	0.71
Net income	$ 1.16	2.09	4.17	5.07
Average common shares outstanding				
Basic	194,290,277	193,517,785	194,126,104	193,342,825
Diluted	195,057,952	194,411,116	194,874,572	194,548,846

* Reclassified to conform to current presentation.
See Notes to Consolidated Financial Statements, page 7.

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Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (unaudited)

(Thousands of dollars)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net income	$ 226,681	406,114	812,189	986,630
Other comprehensive income (loss), net of tax				
Net gain (loss) from foreign currency translation	127,142	(300,506)	142,844	(177,481)
Retirement and postretirement benefit plan amounts reclassified to net income	2,121	9,264	7,793	13,637
Deferred loss on interest rate hedges:				
Increase in deferred loss associated with contract revaluation and settlement	0	(13,469)	(2,407)	(13,469)
Amount of loss reclassified to interest expense in consolidated statements of income	484	0	724	0
COMPREHENSIVE INCOME	$ 356,428	101,403	961,143	809,317

See Notes to Consolidated Financial Statements, page 7.

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Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Thousands of dollars)

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011[1]
OPERATING ACTIVITIES		
Net income	$ 812,189	986,630
Adjustments to reconcile net income to net cash provided by operating activities:		
Income from discontinued operations	(10,534)	(139,206)
Depreciation, depletion and amortization	972,663	783,531
Amortization of deferred major repair costs	16,876	17,357
Expenditures for asset retirements	(22,949)	(15,171)
Dry hole costs	89,645	118,585
Amortization of undeveloped leases	107,151	90,623
Accretion of asset retirement obligations	29,052	26,162
Deferred and noncurrent income tax charges	155,616	110,670
Pretax gain from disposition of assets	(94)	(23,192)
Net increase in noncash operating working capital	(217,240)	(305,221)
Other operating activities, net	120,862	36,121
Net cash provided by continuing operations	2,053,237	1,686,889
Net cash provided by discontinued operations	47,990	189,858
Net cash provided by operating activities	2,101,227	1,876,747
INVESTING ACTIVITIES		
Property additions and dry hole costs	(2,232,067)	(1,845,000)
Proceeds from sales of assets	388	27,629
Purchase of investment securities[2]	(1,360,746)	(1,233,321)
Proceeds from maturity of investment securities[2]	1,401,235	1,356,175
Expenditures for major repairs	(11,367)	(2,826)
Investing activities of discontinued operations:		
Sales proceeds	0	403,833
Other	(36,524)	(58,534)
Other net	8,898	7,150
Net cash required by investing activities	(2,230,183)	(1,344,894)
FINANCING ACTIVITIES		
Borrowings of notes payable	934,899	384,970
Maturities of notes payable	(350,000)	0
Proceeds from exercise of stock options and employee stock purchase plans	11,138	8,245
Excess tax benefits related to exercise of stock options	1,957	4,119
Withholding tax on stock-based incentive awards	(3,522)	(8,014)
Issue cost of notes payable and debt facility	(4,285)	(8,619)
Cash dividends paid	(167,520)	(159,529)
Net cash provided by financing activities	422,667	221,172
Effect of exchange rate changes on cash and cash equivalents	9,110	(9,869)

Net increase in cash and cash equivalents		302,821	743,156
Cash and cash equivalents at January 1		513,873	535,825
Cash and cash equivalents at September 30	$	816,694	1,278,981

[1] Reclassified to conform to current presentation.

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

See Notes to Consolidated Financial Statements, page 7.

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Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY (unaudited)

(Thousands of dollars)

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Cumulative Preferred Stock par $100, authorized 400,000 shares, none issued	0	0
Common Stock par $1.00, authorized 450,000,000 shares, issued 194,452,935 at September 30, 2012 and 193,719,102 shares at September 30, 2011		
Balance at beginning of period	$ 193,909	193,294
Exercise of stock options	320	425
Awarded restricted stock	224	0
Balance at end of period	194,453	193,719
Capital in Excess of Par Value		
Balance at beginning of period	817,974	767,762
Exercise of stock options, including income tax benefits	12,020	13,755
Restricted stock transactions and other	(5,257)	(15,119)
Stock-based compensation	33,842	32,255
Sale of stock under employee stock purchase plans	1,735	912
Balance at end of period	860,314	799,565
Retained Earnings		
Balance at beginning of period	7,460,942	6,800,992
Net income for the period	812,189	986,630
Cash dividends	(167,520)	(159,529)
Balance at end of period	8,105,611	7,628,093
Accumulated Other Comprehensive Income		
Balance at beginning of period	310,420	449,428
Foreign currency translation gains, net of income taxes	142,844	(177,481)
Retirement and postretirement benefit plan adjustments, net of income taxes	7,793	13,637
Change in deferred loss on interest rate hedges, net of income taxes	(1,683)	(13,469)
Balance at end of period	459,374	272,115
Treasury Stock		
Balance at beginning of period	(4,848)	(11,926)
Sale of stock under employee stock purchase plans	1,854	578
Awarded restricted stock, net of forfeitures	0	6,208
Balance at end of period	(2,994)	(5,140)
Total Stockholders Equity	$ 9,616,758	8,888,352

See notes to consolidated financial statements, page 7.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

These notes are an integral part of the financial statements of Murphy Oil Corporation and Consolidated Subsidiaries (Murphy/the Company) on pages 2 through 6 of this Form 10-Q report.

Note A Interim Financial Statements

The consolidated financial statements of the Company presented herein have not been audited by independent auditors, except for the Consolidated Balance Sheet at December 31, 2011. In the opinion of Murphy s management, the unaudited financial statements presented herein include all accruals necessary to present fairly the Company s financial position at September 30, 2012, and the results of operations, cash flows and changes in stockholders equity for the three-month and nine-month periods ended September 30, 2012 and 2011, in conformity with accounting principles generally accepted in the United States. In preparing the financial statements of the Company in conformity with accounting principles generally accepted in the United States, 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.

Financial statements and notes to consolidated financial statements included in this Form 10-Q report should be read in conjunction with the Company s 2011 Form 10-K and Form 10-K/A reports, as certain notes and other pertinent information have been abbreviated or omitted in this report. Financial results for the three-month and nine-month periods ended September 30, 2012 are not necessarily indicative of future results.

Note B Property, Plant and Equipment

Under U.S. generally accepted accounting principles for companies that use the successful efforts method of accounting, 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 September 30, 2012, the Company had total capitalized exploratory well costs pending the determination of proved reserves of $571.8 million. The following table reflects the net changes in capitalized exploratory well costs during the nine-month periods ended September 30, 2012 and 2011.

(Thousands of dollars)	2012	2011
Beginning balance at January 1	$ 556,412	497,765
Additions pending the determination of proved reserves	143,863	31,481
Reclassifications to proved properties based on the determination of proved reserves	(76,633)	0
Capitalized exploratory well costs charged to expense	(51,866)	0
Balance at September 30	$ 571,776	529,246

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed for each individual well and the number of projects for which exploratory well costs have been capitalized. The projects are aged based on the last well drilled in the project.

	September 30,					
	2012			2011		
(Thousands of dollars)	Amount	No. of Wells	No. of Projects	Amount	No. of Wells	No. of Projects
Aging of capitalized well costs:						
Zero to one year	$ 82,521	8	5	$ 92,752	15	5
One to two years	90,390	7	3	69,591	9	1
Two to three years	114,532	6	1	115,924	8	3
Three years or more	284,333	26	6	250,979	37	7

	$ 571,776	47	15	$ 529,246	69	16

Of the $489.3 million of exploratory well costs capitalized more than one year at September 30, 2012, $270.5 million is in Malaysia, $189.5 million is in the U.S. and $29.3 million is in Republic of the Congo. 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. drilling and development operations are planned. In Republic of the Congo further appraisal drilling is planned.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note C Inventories

Inventories are carried at the lower of cost or market. The cost of crude oil and finished products is predominantly determined on the last-in, first-out (LIFO) method. At September 30, 2012 and December 31, 2011, the carrying value of inventories under the LIFO method was $645.4 million and $580.2 million, respectively, less than such inventories would have been valued using the first-in, first-out (FIFO) method.

Note D Discontinued Operations

During the third quarter 2012, the Company s Board of Directors authorized management to sell its exploration and production operations in the United Kingdom. The Company currently expects to complete the sale of these operations near year-end 2012. Beginning in the third quarter 2012, the Company has begun to account for U.K. upstream operations as discontinued operations for all periods presented, including a reclassification of all prior year s results for these operations to discontinued operations.

In 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. On September 30, 2011, the Company sold the Superior, Wisconsin refinery and related assets for $214 million, plus certain capital expenditures between July 25 and the date of closing and the fair value of all associated hydrocarbon inventories at these locations. On October 1, 2011, the Company sold the Meraux, Louisiana refinery and related assets for $325 million, plus the fair value of associated hydrocarbon inventories. The Company has accounted for operating results of the Superior, Wisconsin and Meraux, Louisiana refineries and associated marketing assets as discontinued operations for all prior periods presented. The cash proceeds from these refinery sales were primarily used to pay down outstanding loans under existing revolving credit facilities in 2011.

The results of operations associated with discontinued operations for the three-month and nine-month periods ended September 30, 2012 and 2011 were as follows:

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
(Thousands of dollars)	2012	2011	2012	2011
Revenues	$ 31,779	1,335,452	102,096	3,784,742
Income before income taxes, including a net gain on sale of two U.S. refineries of $15,959 in the three-month and nine-month periods in 2011	10,631	114,842	45,331	248,381
Income tax expense	12,861	56,038	34,797	109,175

In July 2012, the United Kingdom enacted tax changes that limited tax relief on oil and gas decommissioning costs to 50%, a reduction from the 62% tax relief previously allowed for these costs. This tax rate change led to a net increase in tax expense of discontinued operations of $5.5 million in the three-month and nine-month periods that ended September 30, 2012. In July 2011, the United Kingdom enacted a supplemental tax rate increase for oil and gas companies effective retroactive to March 2011. The total U.K. tax rate increased from 50% to 62% for oil and gas companies. The supplemental tax increased income tax expense of discontinued operations by $14.5 million for the three-month and nine-month periods ended September 30, 2011.

The Company continues to offer for sale its U.K. refinery at Milford Haven, Wales and all U.K. product terminals and motor fuel stations. Based on current market conditions, it is possible that the Company could incur a loss on future sales of the U.K. downstream assets. Through September 30, 2012, the Company has accounted for U.K. downstream results as a component of continuing operations. If the sale of the U.K. refining and marketing assets continues to progress, 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note E Financing Arrangements

The Company has a $1.5 billion committed credit facility that expires June 14, 2016. Borrowings under the facility bear interest at 1.5% above LIBOR based on the Company s current credit rating as of September 30, 2012. Facility fees are due at varying rates on the commitment. The Company s shelf registration statement on file with the U.S. Securities and Exchange Commission that permitted the offer and sale of debt and/or equity securities expired in September 2012. In October 2012, the Company filed a Form S-3 with the U.S. Securities and Exchange Commission (SEC) that established a new three-year shelf registration.

Ten year notes totaling $350 million matured on May 1, 2012 and were repaid using $350 million of borrowings from other existing credit facilities. In May 2012, the Company sold $500 million of new notes that carry a coupon rate of 4.00% and mature on June 1, 2022. The new notes pay interest semi-annually on June 1 and December 1, with the initial interest payment to be made on December 1, 2012. The proceeds of the $500 million notes were used to repay the borrowings incurred on May 1 under other credit facilities and for general corporate purposes.

Note F Cash Flow Disclosures

Additional disclosures regarding cash flow activities are provided below.

(Thousands of dollars)	Nine Months Ended September 30, 2012	2011
Net (increase) decrease in operating working capital other than cash and cash equivalents:		
Increase in accounts receivable	$ (98,163)	(314,908)
Increase in inventories	(168,840)	(31,865)
Increase in prepaid expenses	(148,904)	(28,693)
Decrease in deferred income tax assets	23,939	4,797
Increase in accounts payable and accrued liabilities	94,457	189,833
Increase (decrease) in current income tax liabilities	80,271	(124,385)
Total	$ (217,240)	(305,221)
Supplementary disclosures:		
Cash income taxes paid	$ 414,676	608,065
Interest paid, net of amounts capitalized	1,077	18,124

Note G Employee and Retiree Benefit 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.

The table that follows provides the components of net periodic benefit expense for the three-month and nine-month periods ended September 30, 2012 and 2011.

Three Months Ended September 30,	
Pension Benefits	Other Postretirement Benefits

(Thousands of dollars)	2012	2011	2012	2011
Service cost	$ 6,030	5,915	1,049	1,289
Interest cost	7,549	7,919	1,342	1,719
Expected return on plan assets	(6,520)	(6,840)	0	0
Amortization of prior service cost	313	337	(42)	(66)
Amortization of transitional asset	112	(51)	2	3
Recognized actuarial loss	3,846	2,543	453	786
	11,330	9,823	2,804	3,731
Special termination benefits	0	700	0	0
Curtailment expense (gain)	0	1,105	0	(605)
Net periodic benefit expense	$ 11,330	11,628	2,804	3,126

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note G Employee and Retiree Benefit Plans (Contd.)

	Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2012	2011	2012	2011
Service cost	$ 17,953	17,763	3,139	3,803
Interest cost	22,386	23,855	4,133	5,084
Expected return on plan assets	(19,345)	(20,634)	0	0
Amortization of prior service cost	938	1,020	(131)	(196)
Amortization of transitional asset	339	(155)	6	7
Recognized actuarial loss	11,460	7,661	1,394	2,326
	33,731	29,510	8,541	11,024
Special termination benefits	6,170	700	0	0
Curtailment expense (gain)	0	1,105	0	(605)
Net periodic benefit expense	$ 39,901	31,315	8,541	10,419

During the nine-month period ended September 30, 2012, the Company made contributions of $37.9 million to its defined benefit pension and postretirement benefit plans. Remaining funding in 2012 for the Company s defined benefit pension and postretirement plans is anticipated to be $7.5 million.

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. In June 2012, the U.S. Supreme Court upheld the constitutionality of the health care reform law. The Company provides a health care benefit plan to eligible U.S. employees and most U.S. retired employees. The law did not significantly affect the Company s consolidated financial statements as of September 30, 2012 and 2011 and for the three-month and nine-month periods then ended. The Company continues to evaluate the various components of the law as further 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.

Note H Incentive Plans

The 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.

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

The 2012 Annual Plan and the 2007 Annual Plan authorize the Executive Compensation Committee (the Committee) to establish specific performance goals associated with annual cash awards that may be earned by officers, executives and other key employees. Cash awards under the 2012 Annual Plan and 2007 Annual Plan are determined based on the Company s actual financial and operating results as measured against the performance goals established by the Committee. The 2012 Long-Term Plan and the 2007 Long-Term Plan authorize the Committee to make grants of the Company s Common Stock to employees. These grants may be in the form of stock options (nonqualified or incentive), stock appreciation rights (SAR), restricted stock, restricted stock units, performance units, performance shares, dividend equivalents and other stock-based incentives. The 2012 Long-Term Plan expires in 2022. A total of 8,700,000 shares are issuable during the life of the 2012 Long-Term Plan, with annual grants limited to 1% of Common shares outstanding. The Company has an Employee Stock Purchase Plan that permits the issuance of up to 980,000 shares through September 30, 2017. The Company also has a Stock Plan for Non-Employee Directors that permits the issuance of restricted stock and stock options or a combination thereof to the Company s Directors.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note H Incentive Plans (Contd.)

On January 31, 2012, the Committee granted stock options for 1,643,000 shares to certain employees at an exercise price of $59.655 per share under the 2007 Long-Term Plan. The Black-Scholes valuation for these awards was $17.74 per option. The Committee also granted 653,356 performance-based restricted stock units to certain employees on that date under the 2007 Long-Term Plan. The fair value of the performance-based restricted stock units, using a Monte Carlo valuation model, ranged from $54.90 to $63.64 per unit. On February 1, 2012, the Committee granted 40,260 shares of time-based restricted stock units to the Company s Directors under the Non-employee Director Plan. These shares vest on the third anniversary of the date of grant. The fair value of these awards was estimated based on the fair market value of the Company s stock on the date of grant, which was $59.33 per share.

On June 20, 2012, stock options for 227,500 shares were granted to two senior company officers under the 2012 Long-Term Plan. The exercise price of these stock options was $45.70 per share. These stock options vest and become exercisable in periods ranging between six months and three years. The fair value of these stock options using a Black-Scholes valuation model ranged from $12.37 to $13.10 per share. Additionally, on August 1, 2012, the Committee granted 1,996 shares of time-based restricted stock units to a newly elected Company Director. These shares vest on February 1, 2015 and were valued at the fair market value on the date of grant, which was $54.40 per share.

Cash received from options exercised under all share-based payment arrangements for the nine-month periods ended September 30, 2012 and 2011 was $11.1 million and $8.2 million, respectively. The actual income tax benefit realized for the tax deductions from option exercises of the share-based payment arrangements totaled $3.3 million and $7.4 million for the nine-month periods ended September 30, 2012 and 2011, respectively.

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

	Nine Months Ended September 30,	
(Thousands of dollars)	2012	2011
Compensation charged against income before tax benefit	$ 33,952	32,885
Related income tax benefit recognized in income	8,007	9,883

Note I Earnings per Share

Net income was used as the numerator in computing both basic and diluted income per Common share for the three-month and nine-month periods ended September 30, 2012 and 2011. The following table reconciles the weighted-average shares outstanding used for these computations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Weighted-average shares)	2012	2011	2012	2011
Basic method	194,290,277	193,517,785	194,126,104	193,342,825
Dilutive stock options and restricted stock units	767,675	893,331	748,468	1,206,021
Diluted method	195,057,952	194,411,116	194,874,572	194,548,846

The following table reflects certain options to purchase shares of common stock that were outstanding during the 2012 and 2011 periods but were not included in the computation of diluted EPS above because the incremental shares from assumed conversion were antidilutive.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Antidilutive stock options excluded from diluted shares	3,538,507	2,034,087	3,276,850	1,764,565
Weighted average price of these options	$ 63.83	$ 69.28	$ 65.01	$ 69.53

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note J Income Taxes

The Company s effective income tax rate generally exceeds the statutory U.S. tax rate of 35%. The effective tax rate is calculated as the amount of income tax expense divided by income from continuing operations before income tax expense. For the three-month and nine-month periods in 2012 and 2011, the Company s effective income tax rates for continuing operations were as follows:

	2012	2011
Three months ended September 30	43.7%	34.1%
Nine months ended September 30	41.1%	39.7%

The effective tax rates for most periods presented exceeded the U.S. statutory tax rate of 35% due to several factors, including: the effects of income generated in foreign tax jurisdictions; U.S. state tax expense; and certain expenses, including exploration and other expenses in certain foreign jurisdictions, for which no income tax benefits are available or are not presently being recorded due to a lack of reasonable certainty of adequate future revenue against which to utilize these expenses as deductions.

In the third quarter 2011, it was determined that Block P expenditures in Malaysia are deductible against the earnings of adjacent Block K. The Company recorded a $25.6 million income tax benefit in the three-month and nine-month periods ended September 30, 2011 associated with prior-year expenditures in Block P. The Company had previously recognized no tax benefits prior to the third quarter 2011 associated with Block P expenditures.

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 September 30, 2012, the earliest years remaining open for audit and/or settlement in our major taxing jurisdictions are as follows: United States 2009; Canada 2007; United Kingdom 2010; and Malaysia 2006.

Note K Financial Instruments and Risk Management

Murphy periodically utilizes derivative instruments to manage certain risks related to commodity prices, foreign currency exchange rates and interest 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. The Company has a risk management control system to monitor commodity price risks and any derivatives obtained to manage a portion of such risks. For accounting purposes, the Company has not designated commodity and foreign currency derivative contracts as hedges, and therefore, it recognizes all gains and losses on these derivative contracts in its Consolidated Statements of Income. Certain interest rate derivative contracts were accounted for as a hedge and the loss at maturity of these contracts has been deferred in Accumulated Other Comprehensive Income and is being accreted to interest expense over the ten-year term of the associated notes payable.

Commodity Purchase Price Risks

The Company is subject to commodity price risk related to corn that it will purchase in the future for feedstock and for corn that it holds in inventory as feedstock as well as wet and dried distillers grain that it will sell in the future at its ethanol production facilities in the United States. At September 30, 2012 and 2011, the Company had open physical delivery fixed-price commitment contracts for purchase of approximately 8.8 million and 7.9 million bushels of corn, respectively, for processing at its ethanol plants. The Company also had outstanding derivative contracts to sell a similar volume of these fixed-price quantities and buy them back at future prices in effect on the expected date of delivery under the purchase commitment contracts. Additionally, at September 30, 2012 and 2011, the Company had outstanding derivative contracts to sell 3.4 million and 2.3 million bushels of corn, respectively, and buy them back when certain corn inventories are expected to be processed at the Hereford, Texas facility. Also, at September 30, 2012 and 2011, the Company had open physical delivery fixed-price commitment contracts for sale of approximately 1.5 million and 1.6 million equivalent bushels of wet and dried distillers grain, respectively, with outstanding derivative contracts to purchase a similar volume of these fixed-price quantities and sell them back at future prices in effect on the expected date of delivery under the sale commitment contracts. The impact of marking to market these commodity derivative contracts increased income from continuing operations before taxes by $6.3 million and $1.9 million in the nine-month periods ended September 30, 2012 and 2011, respectively.

Cash collateral deposits of $9.2 million at September 30, 2012 associated with these commodity derivative contracts were excluded from the fair value of assets and liabilities included below.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note K Financial Instruments and Risk Management (Contd.)

Foreign Currency Exchange Risks

The Company is subject to foreign currency exchange risk associated with operations in countries outside the United States. Short-term derivative instruments were outstanding at September 30, 2012 and 2011 to manage the risk of certain income taxes that are payable in Malaysian ringgits. The equivalent U.S. dollars of Malaysian ringgit derivative contracts open at September 30, 2012 and 2011 were approximately $97.6 million and $123.3 million, respectively. Short-term derivative instrument contracts totaling $38.0 million U.S. dollars were also outstanding at September 30, 2011 to manage the risk of certain U.S. dollar accounts receivable associated with sale of crude oil production in Canada. The impact from marking to market these foreign currency derivative contracts increased income from continuing operations before taxes by $3.1 million for the nine-month period ended September 30, 2012 and decreased income from continuing operations before taxes by $2.6 million for the nine-month period ended September 30, 2011.

At September 30, 2012 and December 31, 2011, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

(Thousands of dollars)	September 30, 2012 Asset (Liability) Derivatives		December 31, 2011 Asset (Liability) Derivatives	
Type of Derivative Contract	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity	Accounts receivable	$ 9,496	Accounts receivable	$ 197
Commodity	Accounts payable	(3,176)	Accounts payable	(489)
Foreign exchange	Accounts receivable	3,612	Accounts payable	(8,459)

For the three-month and nine-month periods ended September 30, 2012 and 2011, the gains and losses recognized in the Consolidated Statements of Income for derivative instruments not designated as hedging instruments are presented in the following table.

(Thousands of dollars)	Statement of Income	Gain (Loss) Three Months Ended September 30,		Gain (Loss) Nine Months Ended September 30,	
Type of Derivative Contract	Location	2012	2011	2012	2011
Commodity	Crude oil and product purchases	$ (40,241)	7,381	(37,978)	5,900
Foreign exchange	Interest and other income	6,585	(7,376)	15,782	4,614
		$ (33,656)	5	(22,196)	10,514

Interest Rate Risks

The Company had ten-year notes totaling $350 million that matured on May 1, 2012. In May 2012, the Company sold new ten-year notes, and it therefore had risk related to the interest rate associated with the anticipated sale of these notes. To manage this interest rate risk, in 2011 the Company entered into a series of derivative contracts known as forward starting interest rate swaps that matured on May 1, 2012. The Company utilized hedge accounting to defer any gain or loss on these contracts until the payment of interest on these new notes occurs. During the three-month and nine-month periods ended September 30, 2012, $0.7 million and $1.1 million, respectively, of the deferred loss on the interest rate swaps was charged to income. The remaining loss deferred on these contracts at September 30, 2012 was $28.5 million.

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

	December 31, 2011 Asset (Liability) Derivatives	
(Thousands of dollars)		
Type of Derivative Contract	Balance Sheet Location	Fair Value
Interest rate	Accounts Payable	$ (25,927)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note K Financial Instruments and Risk Management (Contd.)

The Company carries certain assets and liabilities at fair value in its Consolidated Balance Sheets. 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 carrying value of assets and liabilities recorded at fair value on a recurring basis at September 30, 2012 and December 31, 2011 are presented in the following table.

	September 30, 2012				December 31, 2011			
(Thousands of dollars)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Commodity derivative contracts	$ 0	9,496	0	9,496	0	197	0	197
Foreign currency exchange derivative contracts	0	3,612	0	3,612	0	0	0	0
	$ 0	13,108	0	13,108	0	197	0	197
Liabilities								
Nonqualified employee savings plans	$ (9,306)	0	0	(9,306)	(8,030)	0	0	(8,030)
Commodity derivative contracts	0	(3,176)	0	(3,176)	0	(489)	0	(489)
Foreign currency exchange derivative contracts	0	0	0	0	0	(8,459)	0	(8,459)
Interest rate derivative contracts	0	0	0	0	0	(25,927)	0	(25,927)
	$ (9,306)	(3,176)	0	(12,482)	(8,030)	(34,875)	0	(42,905)

The fair value of commodity derivative contracts for corn and wet and dried distillers grain was determined based on market quotes for No. 2 yellow corn. The fair value of foreign exchange and interest rate derivative contracts was based on market quotes for similar contracts at the balance sheet date. The income effect of changes in fair value of commodity derivative contracts is recorded in Crude Oil and Product Purchases in the Consolidated Statements of Income and changes in fair value of foreign exchange derivative contracts is recorded in Interest and Other Income. The deferred loss on interest rate derivative contracts is being reclassified to Interest Expense in the Consolidated Statement of Income over the life of the $500 million notes payable that mature June 1, 2022. The nonqualified employee savings plan is an unfunded savings plan through which participants seek a return via phantom investments in equity securities and/or mutual funds. The fair value of this liability was based on quoted prices for these equity securities and mutual funds. The income effect of changes in the fair value of the nonqualified employee savings plan is recorded in Selling and General Expenses.

Note L Accumulated Other Comprehensive Income

The components of Accumulated Other Comprehensive Income on the Consolidated Balance Sheets at September 30, 2012 and December 31, 2011 are presented in the following table.

(Thousands of dollars)	Sept. 30, 2012	Dec. 31, 2011
Foreign currency translation gains, net of tax	$ 639,005	496,161
Retirement and postretirement benefit plan losses, net of tax	(161,096)	(168,889)

Loss deferred on settled interest rate derivative contracts, net of tax	(18,535)	(16,852)
Accumulated other comprehensive income	$ 459,374	310,420

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note M   Environmental and Other 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 and 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.

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. With the sale of the U.S. refineries in 2011, the Company retained certain liabilities related to environmental matters at these sites. The Company also has insurance covering certain levels of environmental expenses at the refinery sites. The Company believes costs related to these sites will not have a material adverse affect on Murphy s net income, financial condition or liquidity in a future period.

The U.S. Environmental Protection Agency (EPA) currently considers the Company to be a Potentially Responsible Party (PRP) at one Superfund site. The potential total cost to all parties to perform necessary remedial work at the Superfund 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. The Company has not recorded a liability for remedial costs on the Superfund site. 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 the Superfund site will be immaterial and will not have a material adverse effect on its net income, financial condition or liquidity in a future period.

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.

In 2011, Murphy was notified by the U.K. Environment Agency (EA) that it failed to surrender sufficient greenhouse gas emission allowances, which Murphy self-reported to the EA in 2010. The EA has issued a civil penalty notice of approximately $1.7 million. The Company is pursuing all available options regarding this matter.

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 these matters is not expected to have a material adverse effect on the Company s net income, financial condition or liquidity in a future period.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note M Environmental and Other Contingencies (Contd.)

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 September 30, 2012, the Company had contingent liabilities of $356.1 million on outstanding letters of credit. The Company has not accrued a liability in its Consolidated Balance Sheets related to these letters of credit because it is believed that the likelihood of having these drawn is remote.

Note N Commitments

The Company has entered into forward sales contracts to mitigate the price risk for a portion of its 2012 natural gas sales volumes in the Tupper area in Western Canada. The contracts call for natural gas deliveries of approximately 50 million cubic feet per day in 2012 at an average price of Cdn$4.43 per MCF, with the contracts calling for delivery at the AECO C sales point. These contracts have been accounted for as a normal sale for accounting purposes.

Note O Terra Nova Working Interest Redetermination

The joint agreement between the owners of the Terra Nova field, offshore Eastern Canada, required a redetermination of working interests based on an analysis of reservoir quality among fault separated areas where varying ownership interests existed. Due to the redetermination process, the Company s working interest at Terra Nova was reduced from its original 12.0% to 10.475% effective January 1, 2011. The Company made a cash settlement payment in the first quarter 2011 to certain Terra Nova partners for the value of oil sold since February 2005, net of adjustments for operating expenses and capital expenditures, related to the working interest reduction. The Company had recorded cumulative expense of $102.1 million through 2010 based on the working interest reduction. Based on the final settlement paid in 2011, the Company recorded a $5.4 million benefit in the six months of 2011 due to the ultimate cost of the redetermination settlement being less than originally estimated. The benefit has been reflected as Redetermination of Terra Nova Working Interest in the Consolidated Statement of Income for the nine-month period ended September 30, 2011.

Note P Accounting Matters

In September 2011, the Financial Accounting Standards Board (FASB) issued an accounting standards update that simplifies the annual goodwill impairment assessment process by permitting a company to assess whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount before applying the two-step goodwill impairment test. If a company concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the company would be required to conduct the current two-step goodwill impairment test. This change was effective for the Company for annual and interim goodwill impairment tests performed in 2012. The Company adopted the standard effective January 1, 2012 and the standard did not have a significant effect on its 2012 consolidated financial statements.

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

In December 2011, the FASB issued an accounting standards update that will enhance disclosures about financial instruments and derivative instruments that are either offset in the balance sheet or are subject to an enforceable master netting arrangement or similar agreement. The guidance will be effective for all interim and annual periods beginning on or after January 1, 2013. The Company does not expect this new guidance to have a significant effect on its consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note Q Business Segments

In the third quarter 2012, the Company s Board of Directors agreed to sell the U.K. exploration and production operations. The assets and liabilities associated with these U.K. operations as of September 30, 2012 are now reported as held for sale in the Consolidated Balance Sheet, and beginning in the third quarter 2012, the results of operations are reported as discontinued operations for all periods presented in the Consolidated Statement of Income and in the segment table that follows. In 2010, the Company announced its intention to sell its two U.S. refineries and its U.K. downstream operations during 2011. On September 30, 2011, the Company completed the sale of the Superior, Wisconsin refinery and associated marketing assets. On October 1, 2011, the Company completed the sale of the Meraux, Louisiana refinery and associated marketing assets. The results of operations for the Superior and Meraux refineries and associated marketing assets have been reported as discontinued operations for all periods presented. The Company continues to actively market for sale the U.K. downstream assets. If the criteria for held for sale under U.S. generally accepted accounting principles is met in future periods, the results of these operations would be presented as discontinued operations.

		Three Mos. Ended Sept. 30, 2012			Three Mos. Ended Sept. 30, 2011[1]		
(Millions of dollars)	Total Assets at Sept. 30, 2012	External Revenues	Inter-segment Revenues	Income (Loss)	External Revenues	Inter-segment Revenues	Income (Loss)
Exploration and production[2]							
United States	$ 2,862.7	248.8	0	33.5	173.2	0	38.2
Canada	4,065.7	232.8	0	29.3	307.4	42.7	102.3
Malaysia	4,586.0	602.2	0	215.7	484.8	0	197.7
Republic of the Congo	249.6	0	0	(4.7)	43.7	0	(.7)
Other	60.4	0	0	(52.7)	0	0	(64.1)
Total	11,824.4	1,083.8	0	221.1	1,009.1	42.7	273.4
Refining and marketing							
United States	1,955.3	4,475.5	0	17.3	4,629.2	0	88.0
United Kingdom	1,128.3	1,571.4	0	25.5	1,552.1	0	(19.1)
Total	3,083.6	6,046.9	0	42.8	6,181.3	0	68.9
Total operating segments	14,908.0	7,130.7	0	263.9	7,190.4	42.7	342.3
Corporate	1,473.3	(8.5)	0	(35.0)	29.8	0	5.0
Assets/revenue/income from continuing operations	16,381.3	7,122.2	0	228.9	7,220.2	42.7	347.3
Discontinued operations, net of tax	208.5	0	0	(2.2)	0	0	58.8
Total	$ 16,589.8	7,122.2	0	226.7	7,220.2	42.7	406.1

	Nine Months Ended Sept. 30, 2012			Nine Months Ended Sept. 30, 2011[1]		
(Millions of dollars)	External Revenues	Inter-segment Revenues	Income (Loss)	External Revenues	Inter-segment Revenues	Income (Loss)
Exploration and production[2]						
United States	$ 671.6	0	83.1	539.7	0	106.8
Canada	804.7	0	146.3	827.7	137.4	284.5
Malaysia	1,777.5	0	662.9	1,442.1	0	559.5
Republic of the Congo	57.6	0	(8.4)	111.4	0	(.4)

Other	.1	0	(123.9)	24.4	0	(191.6)
Total	3,311.5	0	760.0	2,945.3	137.4	758.8
Refining and marketing						
United States	13,251.8	0	83.4	13,356.1	0	172.9
United Kingdom	4,668.1	0	35.7	4,499.0	0	(43.6)
Total	17,919.9	0	119.1	17,855.1	0	129.3
Total operating segments	21,231.4	0	879.1	20,800.4	137.4	888.1
Corporate	5.4	0	(77.4)	43.7	0	(40.7)
Revenue/income from continuing operations	21,236.8	0	801.7	20,844.1	137.4	847.4
Discontinued operations, net of tax	0	0	10.5	0	0	139.2
Total	$ 21,236.8	0	812.2	20,844.1	137.4	986.6

[1] Reclassified to conform to current presentation.
[2] Additional details about results of oil and gas operations are presented in the tables on pages 24 and 25.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note R   Subsequent Events

On October 16, 2012, the Company announced that it planned to separate its U.S. downstream business into an independent publicly traded company. This separation is currently estimated to be completed in 2013. The Company also announced a $2.50 per share special dividend to be paid on December 3, 2012 to shareholders of record on November 16, 2012. This dividend will amount to approximately a $486 million payout to shareholders. Furthermore, the Company announced a stock buyback program of up to $1 billion of the Company s common stock. The Company expects that a significant portion of the special dividend and stock buyback program will be financed with new long-term debt.

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ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

Results of Operations

Murphy s net income in the third quarter of 2012 was $226.7 million ($1.16 per diluted share) compared to net income of $406.1 million ($2.09 per diluted share) in the third quarter of 2011. The income reduction in 2012 primarily related to lower sales prices for the Company s North American natural gas production, lower margins on U.S. retail marketing operations, unfavorable effects from foreign exchange movements, income tax benefits in Malaysia in 2011 that did not repeat, and profits in 2011 from discontinued operations. These factors were partially offset by higher crude oil sales volumes and significantly stronger results for U.K. refining operations. Income from continuing operations was $228.9 million ($1.17 per diluted share) in the 2012 quarter and $347.3 million ($1.79 per diluted share) in the comparable 2011 quarter. The Company has approved a plan to sell its U.K. exploration and production business and currently expects to complete the sale near year-end 2012. As such, the Company now accounts for the results of the U.K. upstream business as discontinued operations for all periods presented. The Company sold its two U.S. refineries near the end of the third quarter 2011 and has reported these results of operations, as well as the net gain of $16.9 million on sale, as discontinued operations in 2011. The 2012 quarterly net income included a loss from discontinued operations of $2.2 million ($0.01 per diluted share) compared to income of $58.8 million ($0.30 per diluted share) in the 2011 quarter.

For the first nine months of 2012, net income totaled $812.2 million ($4.17 per diluted share) compared to net income of $986.6 million ($5.07 per diluted share) for the same period in 2011. The decline in net income in 2012 compared to 2011 was attributable to several factors, including lower U.S. retail marketing margins, no repeat of foreign currency profits generated in the prior year, and significantly lower income from discontinued operations in the current year. Income from continuing operations in the 2012 and 2011 nine months was $801.7 million ($4.12 per diluted share) and $847.4 million ($4.36 per diluted share), respectively. Income from discontinued operations totaled $10.5 million ($0.05 per diluted share) in the nine-month period of 2012, compared to income of $139.2 million ($0.71 per diluted share) in 2011. The prior-year results of discontinued operations were driven by profitable U.S. refining margins and a $16.9 million after-tax gain on sale of the refineries.

Murphy s income from continuing operations by operating business is presented below.

	Income (Loss)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(Millions of dollars)	2012	2011	2012	2011
Exploration and production	$ 221.1	273.4	760.0	758.8
Refining and marketing	42.8	68.9	119.1	129.3
Corporate	(35.0)	5.0	(77.4)	(40.7)
Income from continuing operations	$ 228.9	347.3	801.7	847.4

In the 2012 third quarter, the Company s exploration and production continuing operations earned $221.1 million compared to $273.4 million in the 2011 quarter. Income in the 2012 quarter was unfavorably impacted compared to 2011 by lower North American natural gas sales prices and higher extraction costs. These factors were somewhat offset by the benefits of higher crude oil sales volumes in 2012. Exploration expenses were $94.0 million in the third quarter of 2012 compared to $85.5 million in the same period of 2011. The Company s refining and marketing operations generated income from continuing operations of $42.8 million in the 2012 third quarter compared to a profit of $68.9 million in the same quarter of 2011. U.S. retail marketing margins were lower in the 2012 quarter compared to the 2011 quarter, but refining and marketing results in the U.K. were very favorable to the prior year due to improved refining margins. The corporate function had after-tax costs of $35.0 million in the 2012 third quarter compared to an after-tax benefit of $5.0 million in the 2011 period with the unfavorable variance in 2012 mostly due to losses on transactions denominated in foreign currencies in 2012 compared to gains on such transactions in the 2011 quarter.

In the first nine months of 2012, the Company s exploration and production continuing operations earned $760.0 million compared to $758.8 million in the same period of 2011. Upstream earnings in 2012 were essentially flat with the prior year as higher crude oil and natural gas sales volumes and lower exploration expenses were offset by lower North American natural gas sales prices and higher extraction costs. Exploration expenses declined from $303.8 million in the first nine months of 2011 to $243.7 million in the 2012 period, as the prior year had higher unsuccessful wildcat drilling costs for wells offshore Indonesia, Suriname and Brunei, as well as higher geophysical costs in the Gulf of Mexico, Brunei and the Kurdistan region of Iraq. The Company s refining and marketing continuing operations had earnings of $119.1 million in the first nine months of 2012 compared to earnings of

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)

Results of Operations ***(Contd.)***

$129.3 million in the same 2011 period. The 2012 period included weaker results in the U.S. retail marketing business compared to a year ago based on lower operating margins. However, the results from U.K. refining and marketing operations were significantly better in 2012 compared to 2011 due to improved margins at the Milford Haven, Wales, refinery. Corporate after-tax costs were $77.4 million in the 2012 period compared to after-tax costs of $40.7 million in the 2011 period. The current period had an unfavorable impact from losses on transactions denominated in foreign currencies, while the prior year included benefits from these transactions.

Exploration and Production

Results of exploration and production continuing operations are presented by geographic segment below.

	Income (Loss)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(Millions of dollars)	2012	2011	2012	2011
Exploration and production continuing operations				
United States	$ 33.5	38.2	83.1	106.8
Canada	29.3	102.3	146.3	284.5
Malaysia	215.7	197.7	662.9	559.5
Republic of the Congo	(4.7)	(0.7)	(8.4)	(0.4)
Other International	(52.7)	(64.1)	(123.9)	(191.6)
Total	$ 221.1	273.4	760.0	758.8

Third quarter 2012 vs. 2011

United States exploration and production operations had earnings of $33.5 million in the third quarter of 2012 compared to earnings of $38.2 million in the 2011 quarter. Results were weaker in the 2012 period as the benefits of higher crude oil and natural gas sales volumes were more than offset by a combination of weaker oil and natural gas sales prices and higher expenses for hydrocarbon extraction and exploration activities. Oil and natural gas production volumes were higher in 2012 due to new producing wells at the Eagle Ford Shale development in South Texas. Production and depreciation expenses increased $32.8 million and $41.7 million, respectively, in 2012 compared to 2011 mostly due to higher production in the Eagle Ford Shale area. Exploration expenses in the 2012 quarter were $4.6 million higher due to additional leasehold amortization for acreage acquired in the Eagle Ford Shale area, partially offset by lower geophysical costs in the Eagle Ford Shale.

Operations in Canada had earnings of $29.3 million in the third quarter 2012 compared to earnings of $102.3 million in the 2011 quarter. Canadian earnings were lower in 2012 mostly due to weaker oil and natural gas sales prices and lower oil and natural gas sales volumes. Oil sales volumes were down in the 2012 period compared to 2011 primarily due to the Terra Nova field, offshore Newfoundland, being shut-in for maintenance during the current quarter. Natural gas sales volumes decreased in 2012 due to voluntary curtailment of production, coupled with deferral of development drilling activities, at the Tupper area due to very weak sales prices for North American natural gas. Production expenses in 2012 for conventional operations matched 2011 levels despite significantly lower production volumes because the current period included maintenance costs for the Terra Nova field while it was down for turnaround. Depreciation expense for conventional operations in Canada was favorable by $9.3 million in 2012 due primarily to lower oil volumes sold at Terra Nova and lower gas volumes produced in the Tupper area.

Operations in Malaysia reported earnings of $215.7 million in the 2012 quarter compared to earnings of $197.7 million during the same period in 2011. Earnings were improved in 2012 in Malaysia primarily due to higher oil sales volumes from the Kikeh and Sarawak fields. Additionally, average oil sales prices rose in 2012 compared to the prior year. Total extraction expenses increased in the 2012 quarter due to higher oil sales volumes. Exploration expense was $22.9 million higher in 2012 primarily due to dry hole costs in Blocks P and SK 311 in the current period. An income tax benefit of $25.6 million was recognized in the third quarter 2011 for costs incurred in prior years in Block P, offshore Sabah, after it was determined that Block P costs are deductible against taxable earnings of Block K. The Company had not recognized income tax benefits for Block P costs prior to 2011.

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)

Results of Operations *(Contd.)*

Exploration and Production (Contd.)

Third quarter 2012 vs. 2011 (Contd.)

Operations in Republic of the Congo incurred a loss of $4.7 million in the third quarter of 2012 compared to a loss of $0.7 million in the 2011 quarter. The 2012 quarter had a larger loss than 2011 primarily due to the costs of a well workover that began in the third quarter 2012 and carries over to quarter four. Production and depreciation expense declined due to no crude oil volumes sold in the 2012 third quarter.

Other international operations reported a loss of $52.7 million in the third quarter of 2012 compared to a loss of $64.1 million in the 2011 period. The smaller loss in the current quarter was primarily attributable to lower exploration expenses compared to the prior year. The 2012 quarter included unsuccessful exploratory drilling costs on the Central Dohuk license in the Kurdistan region of Iraq, while the 2011 quarter included unsuccessful exploratory drilling costs and seismic costs associated with licenses offshore Brunei, and higher geophysical and lease amortization costs on exploration licenses in the Kurdistan region of Iraq.

On a worldwide basis, the Company s crude oil, condensate and gas liquids sales prices averaged $96.09 per barrel in the third quarter 2012 compared to $95.95 in the 2011 period. Total hydrocarbon production averaged 181,558 barrels of oil equivalent per day in the 2012 third quarter, up from the 174,801 barrels equivalent per day produced in the 2011 quarter. Average crude oil and liquids production was 105,796 barrels per day in the third quarter of 2012 compared to 96,437 barrels per day in the third quarter of 2011, with the increase primarily attributable to higher oil production in the Eagle Ford Shale area of South Texas and at the Kikeh field. Development drilling operations continued in the Eagle Ford Shale and new wells have been brought on production at Kikeh. Canadian offshore crude oil production at Terra Nova was lower in 2012 due to production being shut-in during the quarter for equipment maintenance. Canadian heavy oil volumes were lower in 2012 mostly due to production being hampered by pipeline constraints in the Seal area in the current year. Synthetic crude oil production was higher in 2012 due to less downtime for maintenance in the current quarter. Oil production in the Republic of Congo was lower in 2012 primarily due to a well at the Azurite field being offline during the quarter pending completion of an ongoing workover. North American natural gas sales prices averaged $2.61 per thousand cubic feet (MCF) in the 2012 quarter compared to $4.20 per MCF in the same quarter of 2011. Natural gas produced in 2012 at fields offshore Sarawak was sold at $7.59 per MCF, compared to a sale price of $7.54 per MCF in the 2011 quarter. Natural gas sales volumes averaged 454 million cubic feet per day in the third quarter 2012, down from 470 million cubic feet per day in the 2011 quarter. The reduction in natural gas sales volumes in 2012 was primarily due to a voluntary shut-in and reduced development drilling activity at the Tupper area in British Columbia due to weak natural gas sales prices in the area. Natural gas production at fields offshore Sarawak, Malaysia, was lower in 2012 compared to the prior quarter mainly due to maintenance at the third party onshore receiving facility. Natural gas production in the Eagle Ford Shale area was higher in the 2012 quarter due to additional wells onstream in the current year.

Nine months 2012 vs. 2011

U.S. exploration and production operations had income of $83.1 million for the nine months ended September 30, 2012 compared to income of $106.8 million in the 2011 period. The 2012 period benefited from higher crude oil and natural gas sales volumes and slightly higher realized crude oil sales prices, but natural gas sales prices were significantly lower in 2012 compared to the prior year. Crude oil and natural gas production volumes increased in 2012 primarily due to new wells added in the Eagle Ford Shale area. Production and depreciation expenses were $58.8 million and $78.7 million, respectively, more in 2012 than 2011 primarily due to higher production in the Eagle Ford Shale area. Exploration expense in the 2012 period was $18.7 million more than 2011 levels primarily due to higher unsuccessful exploration drilling expense in the Gulf of Mexico and higher undeveloped lease amortization in the Eagle Ford Shale area in the later year, but these were partially offset by higher costs in 2011 for geophysical expense in the Eagle Ford Shale and the Gulf of Mexico. Selling and general expenses rose by $6.3 million in 2012 compared to 2011 essentially due to higher costs for employee compensation and other professional services.

Canadian operations had income of $146.3 million in the first nine months of 2012 compared to income of $284.5 million a year ago. Lower sales prices for oil and natural gas and higher extraction expenses were the primary drivers to the reduction in 2012 earnings. Production expense for conventional operations increased $16.6 million in 2012 mostly related to higher maintenance costs at Terra Nova and higher field costs at the Seal heavy oil area. Depreciation expense for conventional operations increased $20.6 million in 2012 primarily due to higher natural gas

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)
Results of Operations *(Contd.)*

Exploration and Production (Contd.)

Nine months 2012 vs. 2011 (Contd.)

production at Tupper West in the current year. The 2011 period included a benefit of $5.4 million associated with a required redetermination of working interest at the Terra Nova field, offshore Newfoundland. Selling and general expenses increased by $2.7 million in 2012 due to higher compensation and other office costs.

Malaysia operations earned $662.9 million in the first nine months of 2012 compared to earnings of $559.5 million in the 2011 period. Results were stronger in 2012 primarily due to higher sales prices for crude oil and Sarawak natural gas production and higher crude oil sales volumes. These favorable variances were partially offset by several unfavorable cost categories. Depreciation expense in 2012 was $114.0 million more than the 2011 period due to higher crude oil sales volumes and an ongoing development program at the Kikeh field. Exploration expense was $17.3 million higher in 2012 mostly due to dry hole costs in Blocks P and SK 311 in 2012, while the 2011 period included higher geophysical costs for 3D seismic acquisition and processing in Block H. Additionally, a $25.6 million income tax benefit was recognized in 2011 because it was determined that prior year Block P costs are deductible against taxable earnings from Block K.

Operations in Republic of the Congo had a loss of $8.4 million for the nine-month 2012 period, compared to a loss of $0.4 million in the 2011 period. The unfavorable variance in 2012 was primarily attributable to lower crude oil sales volumes at the offshore Azurite field in the current year and production expense associated with a well workover that was in progress at the end of the 2012 third quarter. Depreciation expense was down $30.7 million in 2012 due to lower sales volumes at Azurite. Exploration expense was $4.9 million lower in 2012 than 2011 as the prior year had higher dry hole and geophysical costs. Selling and general expense in 2012 was $2.3 million above 2011 levels due to lower overhead amounts chargeable to drilling operations in the current period.

Other international operations reported a loss of $123.9 million in the first nine months of 2012 compared to a loss of $191.6 million in the 2011 period. The smaller 2012 loss primarily related to lower dry hole costs of $84.7 million, mostly associated with unsuccessful offshore wildcat drilling that occurred in the prior year in Indonesia, Suriname and Brunei. Dry hole costs in 2012 were principally associated with a well on the Central Dohuk license in the Kurdistan region of Iraq. Lower geophysical expense of $16.1 million in 2012 was primarily related to prior-year costs for 3D seismic acquired offshore Brunei and studies on exploration licenses in the Kurdistan region of Iraq. Higher undeveloped leasehold amortization of $8.2 million in 2012 compared to 2011 was attributable to exploration licenses in the Kurdistan region of Iraq. Other exploration expenses increased $2.6 million in 2012 due to higher costs for various exploration field offices. Selling and general expenses were $6.5 million higher in 2012 primarily due to additional office costs supporting international exploration activities. The 2011 nine-month period included an after-tax gain of $13.1 million associated with sale of the Company s gas storage assets in Spain.

For the first nine months of 2012, the Company s sales price for crude oil, condensate and gas liquids averaged $97.13 per barrel, up from $94.36 per barrel in 2011. Total worldwide production averaged 188,385 barrels of oil equivalent per day during the nine months ended September 30, 2012, up from 175,776 barrels of oil equivalent produced in the same period in 2011. Crude oil, condensate and gas liquids production in the first nine months of 2012 averaged 105,766 barrels per day compared to 101,269 barrels per day a year ago. The increase was mostly attributable to higher oil production in the Eagle Ford Shale area where development drilling operations are ongoing, and at the Kikeh field, offshore Sabah, Malaysia, where new wells have been brought on production. Crude oil production offshore eastern Canada was lower in 2012 due to shut-in of the Terra Nova field for several months to conduct maintenance on the production facility and overall field decline at Hibernia. Crude oil production volume in Republic of the Congo decreased in 2012 primarily due to a well being off-line for most of the period awaiting a workover that was in progress at September 30, 2012. The average sales price for North American natural gas in the first nine months of 2012 was $2.43 per MCF, down from $4.26 per MCF realized in 2011. Natural gas production at fields offshore Sarawak was sold at an average price of $7.79 per MCF in 2012 compared to $6.76 per MCF in 2011. Natural gas sales volumes increased from 447 million cubic feet per day in 2011 to almost 496 million cubic feet per day in 2012, with the increase mostly due to higher gas production volumes at the Tupper area. This field commenced production in February 2011 and development operations in 2011 and early 2012 led to more gas wells being put on production after start-up.

Additional details about results of oil and gas operations are presented in the tables on pages 24 and 25.

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ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS (Contd.)
Results of Operations *(Contd.)*

Exploration and Production (Contd.)

Selected operating statistics for the three-month and nine-month periods ended September 30, 2012 and 2011 follow.

Exploration and Production	Three Months Ended September 30, 2012	2011	Nine Months Ended September 30, 2012	2011
Net crude oil, condensate and gas liquids produced barrels per day	105,796	96,437	105,766	101,269
Continuing operations	102,111	94,935	102,354	98,956
United States	26,193	16,388	22,088	16,750
Canada light	249	107	251	74
heavy	6,175	7,097	7,148	6,875
offshore	3,392	9,758	7,105	9,284
synthetic	15,111	14,022	13,297	13,878
Malaysia	49,055	42,976	50,175	46,684
Republic of the Congo	1,936	4,587	2,290	5,411
Discontinued operations United Kingdom	3,685	1,502	3,412	2,313
Net crude oil, condensate and gas liquids sold barrels per day	105,640	93,394	106,322	98,663
Continuing operations	102,704	91,751	103,262	96,292
United States	26,193	16,388	22,088	16,750
Canada light	249	107	251	74
heavy	6,175	7,097	7,148	6,875
offshore	3,324	10,262	7,417	9,381
synthetic	15,111	14,022	13,297	13,878
Malaysia	51,652	39,329	51,100	45,374
Republic of the Congo		4,546	1,961	3,960
Discontinued operations United Kingdom	2,936	1,643	3,060	2,371
Net natural gas sold thousands of cubic feet per day	454,573	470,183	495,711	447,044
Continuing operations	451,798	467,081	492,541	442,638
United States	48,755	38,790	50,611	47,789
Canada	197,434	210,735	227,144	174,635
Malaysia Sarawak	160,419	181,265	175,412	176,067
Kikeh	45,190	36,291	39,374	44,147
Discontinued operations United Kingdom	2,775	3,102	3,170	4,406
Total net hydrocarbons produced equivalent barrels per day (1)	181,558	174,801	188,385	175,776
Total net hydrocarbons sold equivalent barrels per day (1)	181,402	171,758	188,941	173,170
Weighted average sales prices				
Crude oil, condensate and natural gas liquids dollars per barrel (2)				
United States	$ 99.71	102.05	103.69	102.33
Canada (3) light	77.78	90.24	82.03	93.85
heavy	45.89	49.78	47.67	55.08
offshore	110.67	112.47	112.55	110.08
synthetic	89.99	101.18	92.12	103.08
Malaysia (4)	100.52			