MURPHY OIL CORP /DE
Form 10-Q
November 04, 2011
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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, 2011

OR

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

For the transition period from to

Commission File Number 1-8590

MURPHY OIL CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**71-0361522**
(State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**Identification Number)**
200 Peach Street	
P.O. Box 7000, El Dorado, Arkansas	**71731-7000**
(Address of principal executive offices)	**(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. þ 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). þ 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	þ	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 þ No

Number of shares of Common Stock, $1.00 par value, outstanding at September 30, 2011 was 193,521,911**.**

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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) Sept. 30, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,278,981	535,825
Canadian government securities with maturities greater than 90 days at the date of acquisition	493,705	616,558
Accounts receivable, less allowance for doubtful accounts of $7,945 in 2011 and $7,954 in 2010	1,780,976	1,467,311
Inventories, at lower of cost or market		
Crude oil and blend stocks	237,999	147,256
Finished products	195,678	388,162
Materials and supplies	205,023	226,795
Prepaid expenses	113,841	88,241
Deferred income taxes	75,748	80,545
Assets held for sale	78,679	0
Total current assets	4,460,630	3,550,693
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $6,121,765 in 2011 and $6,040,996 in 2010	10,338,783	10,367,847
Goodwill	40,716	42,850
Deferred charges and other assets	184,606	271,853
Assets held for sale	466,347	0
Total assets	$ 15,491,082	14,233,243
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 349,975	41
Accounts payable and accrued liabilities	2,792,520	2,572,105
Income taxes payable	321,375	358,764
Total current liabilities	3,463,870	2,930,910
Long-term debt	974,541	939,350
Deferred income taxes	1,230,237	1,212,213
Asset retirement obligations	566,597	555,248
Deferred credits and other liabilities	367,485	395,972
Stockholders equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued	0	0
Common Stock, par $1.00, authorized 450,000,000 shares, issued 193,719,102 shares in 2011 and 193,293,526 shares in 2010	193,719	193,294
Capital in excess of par value	799,565	767,762
Retained earnings	7,628,093	6,800,992
Accumulated other comprehensive income	272,115	449,428
	(5,140)	(11,926)

Treasury stock, 197,191 shares of Common Stock in 2011 and 457,518 shares of Common Stock in 2010, at cost		
Total stockholders equity	8,888,352	8,199,550
Total liabilities and stockholders equity	$ 15,491,082	14,233,243

See Notes to Consolidated Financial Statements, page 7.

The Exhibit Index is on page 37.

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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, 2011	Three Months Ended September 30, 2010*	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010*
REVENUES				
Sales and other operating revenues	$ 7,211,407	5,210,807	20,865,047	14,665,786
Gain on sale of assets	60	208	23,192	997
Interest and other income (expense)	28,976	(10,681)	39,802	(61,140)
Total revenues	7,240,443	5,200,334	20,928,041	14,605,643
COSTS AND EXPENSES				
Crude oil and product purchases	5,727,873	3,990,497	16,633,221	11,015,394
Operating expenses	521,864	437,926	1,471,901	1,218,625
Exploration expenses, including undeveloped lease amortization	85,688	62,046	304,500	181,503
Selling and general expenses	73,561	63,892	220,753	189,416
Depreciation, depletion and amortization	272,914	272,621	793,445	828,918
Accretion of asset retirement obligations	9,351	8,104	28,494	23,561
Redetermination of Terra Nova working interest	0	4,491	(5,351)	15,353
Interest expense	17,329	12,751	41,648	41,453
Interest capitalized	(2,475)	(4,708)	(11,547)	(11,069)
Total costs and expenses	6,706,105	4,847,620	19,477,064	13,503,154
Income from continuing operations before income taxes	534,338	352,714	1,450,977	1,102,489
Income tax expense	198,597	155,277	596,778	472,411
Income from continuing operations	335,741	197,437	854,199	630,078
Income from discontinued operations, net of taxes	70,373	5,395	132,431	(6,066)
NET INCOME	$ 406,114	202,832	986,630	624,012
INCOME PER COMMON SHARE BASIC				
Income from continuing operations	$ 1.74	1.03	4.42	3.29
Income from discontinued operations	0.36	0.03	0.68	(0.03)
Net income	$ 2.10	1.06	5.10	3.26
INCOME PER COMMON SHARE DILUTED				
Income from continuing operations	$ 1.73	1.02	4.39	3.27
Income from discontinued operations	0.36	0.03	0.68	(0.03)
Net income	$ 2.09	1.05	5.07	3.24
Average common shares outstanding				
Basic	193,517,785	191,943,813	193,342,825	191,577,000

Diluted	194,411,116	193,437,992	194,548,846	192,866,485

* 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,	
	2011	2010	2011	2010
Net income	$ 406,114	202,832	986,630	624,012
Other comprehensive income (loss), net of tax				
Net gain (loss) from foreign currency translation	(300,506)	115,670	(177,481)	75,285
Retirement and postretirement benefit plan adjustments	9,264	2,199	13,637	6,726
Loss deferred on interest rate hedges	(13,469)	0	(13,469)	0
COMPREHENSIVE INCOME	$ 101,403	320,701	809,317	706,023

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, 2011	2010[1]
OPERATING ACTIVITIES		
Net income	$ 986,630	624,012
Adjustments to reconcile net income to net cash provided by operating activities:		
(Income) loss from discontinued operations	(132,431)	6,066
Depreciation, depletion and amortization	793,445	828,918
Amortization of deferred major repair costs	17,357	10,047
Expenditures for asset retirements	(18,399)	(34,376)
Dry hole costs	118,585	35,045
Amortization of undeveloped leases	90,623	76,816
Accretion of asset retirement obligations	28,494	23,561
Deferred and noncurrent income tax charges	125,461	38,939
Pretax gain from disposition of assets	(23,192)	(997)
Net (increase) decrease in noncash operating working capital	(309,436)	417,237
Other operating activities, net	36,121	123,663
Net cash provided by continuing operations	1,713,258	2,148,931
Net cash provided by discontinued operations	163,489	51,950
Net cash provided by operating activities	1,876,747	2,200,881
INVESTING ACTIVITIES		
Property additions and dry hole costs	(1,853,939)	(1,532,446)
Proceeds from sales of assets	27,629	2,195
Purchase of investment securities[2]	(1,233,321)	(1,862,609)
Proceeds from maturity of investment securities[2]	1,356,175	2,011,386
Expenditures for major repairs	(2,826)	(58,453)
Investing activities of discontinued operations, including proceeds from sale of Superior refinery and associated inventories	354,238	(116,757)
Other net	7,150	(31,225)
Net cash required by investing activities	(1,344,894)	(1,587,909)
FINANCING ACTIVITIES		
Borrowings (repayments) of notes payable	384,970	(247,028)
Repayment of nonrecourse debt of a subsidiary	0	(82,000)
Proceeds from exercise of stock options and employee stock purchase plans	8,245	26,100
Excess tax benefits related to exercise of stock options	4,119	9,585
Withholding tax on stock-based incentive awards	(8,014)	(5,170)
Issue cost of debt facility	(8,619)	0
Cash dividends paid	(159,529)	(148,439)
Net cash provided (required) by financing activities	221,172	(446,952)
Effect of exchange rate changes on cash and cash equivalents	(9,869)	(4,772)

Net increase in cash and cash equivalents	743,156	161,248
Cash and cash equivalents at January 1	535,825	301,144
Cash and cash equivalents at September 30	$ 1,278,981	462,392

[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, 2011	2010
Cumulative Preferred Stock par $100, authorized 400,000 shares, none issued	0	0
Common Stock par $1.00, authorized 450,000,000 shares, issued 193,719,102 at September 30, 2011 and 192,835,791 shares at September 30, 2010		
Balance at beginning of period	$ 193,294	191,798
Exercise of stock options	425	1,038
Balance at end of period	193,719	192,836
Capital in Excess of Par Value		
Balance at beginning of period	767,762	680,509
Exercise of stock options, including income tax benefits	13,755	34,973
Restricted stock transactions and other	(15,119)	(9,688)
Stock-based compensation	32,255	30,712
Sale of stock under employee stock purchase plans	912	717
Balance at end of period	799,565	737,223
Retained Earnings		
Balance at beginning of period	6,800,992	6,204,316
Net income for the period	986,630	624,012
Cash dividends	(159,529)	(148,439)
Balance at end of period	7,628,093	6,679,889
Accumulated Other Comprehensive Income		
Balance at beginning of period	449,428	287,187
Foreign currency translation gains (losses), net of income taxes	(177,481)	75,285
Retirement and postretirement benefit plan adjustments, net of income taxes	13,637	6,726
Loss deferred on interest rate hedges, net of income taxes	(13,469)	0
Balance at end of period	272,115	369,198
Treasury Stock		
Balance at beginning of period	(11,926)	(17,784)
Sale of stock under employee stock purchase plans	578	994
Awarded restricted stock, net of forfeitures	6,208	4,305
Cancellation of performance-based restricted stock and forfeitures	0	258
Balance at end of period	(5,140)	(12,227)

Total Stockholders Equity	$ 8,888,352	7,966,919

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, 2010. 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, 2011, and the results of operations, cash flows and changes in stockholders equity for the three-month and nine-month periods ended September 30, 2011 and 2010, 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 2010 Form 10-K report, 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, 2011 are not necessarily indicative of future results. All periods presented have been adjusted to present discontinued operations as discussed in Note D.

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, 2011, the Company had total capitalized exploratory well costs pending the determination of proved reserves of $529.2 million. The following table reflects the net changes in capitalized exploratory well costs during the nine-month periods ended September 30, 2011 and 2010.

(Thousands of dollars)	2011	2010
Beginning balance at January 1	$ 497,765	369,862
Additions pending the determination of proved reserves	31,481	89,797
Reclassifications to proved properties based on the determination of proved reserves	0	0
Balance at September 30	$ 529,246	459,659

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,					
	2011			2010		
(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	$ 92,752	15	5	$ 83,642	13	5
One to two years	69,591	9	1	118,776	12	3
Two to three years	115,924	8	3	50,604	4	4

Three years or more	250,979	37	7	206,637	32	3
	$ 529,246	69	16	$ 459,659	61	15

Of the $436.5 million of exploratory well costs capitalized more than one year at September 30, 2011, $273.1 million is in Malaysia, $137.5 million is in the U.S., $15.3 million is in Republic of the Congo, and $10.6 million 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. drilling and development operations are planned. In Republic of the Congo further appraisal drilling is planned. In Canada a drilling and development program continues.

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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, 2011 and December 31, 2010, the carrying value of inventories under the LIFO method was $824.5 million and $735.1 million, respectively, less than such inventories would have been valued using the first-in, first-out (FIFO) method.

Note D Discontinued Operations

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. Following the 2010 announcement the Company actively marketed its Meraux, Louisiana and Superior, Wisconsin refineries and certain associated product terminals to interested parties. The Company has also offered for sale its U.K. refinery at Milford Haven, Wales, and all U.K. product terminals and motor fuel stations. On July 25, 2011, the Company announced that it had entered into an agreement to sell 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. The sale of the Superior refinery assets was completed on September 30, 2011. On September 1, 2011, the Company announced that it had entered into an agreement to sell its Meraux, Louisiana refinery and related assets for $325 million, plus the fair value of associated hydrocarbon inventories. The sale of the Meraux assets was completed on October 1, 2011. The Company began to account for the Superior, Wisconsin and Meraux, Louisiana refineries and associated marketing assets as discontinued operations beginning in the third quarter 2011. All prior periods presented have been reclassified to conform to this presentation of the Superior and Meraux operating results as discontinued operations. The after-tax gain from disposal of the two refineries netted to $16.9 million, made up of a gain on the Superior refinery (including associated inventories) of $91.1 million and a loss on the Meraux refinery (including associated inventories) estimated at $74.2 million. The gain on disposal was based on refinery selling prices, plus the sales of all associated inventories at fair value, which was significantly above the last-in, first-out carrying value of the inventories sold. A loss on the sale of Meraux has been recorded in the third quarter 2011 because the Meraux business unit qualified for accounting purposes as an asset held for sale, which requires losses to be recorded when they can be estimated based on net realizable sales proceeds. Assets and liabilities associated with the Meraux refinery are presented as held for sale in the Company s Consolidated Balance Sheet as of September 30, 2011. The sale process for the U.K. refining and marketing assets continues. Based on current market conditions, it is possible that the Company could incur a loss on future sales of the U.K. downstream assets.

Assets and liabilities presented in the September 30, 2011 Consolidated Balance Sheet as held for sale related to the Meraux refinery and associated assets were as follows:

(Thousands of dollars)	
Current Assets:	
Accounts receivable	$ 1,243
Liquid inventories	51,268
Materials and supplies inventories	23,076
Other	3,092
	78,679
Noncurrent Assets:	
Property, plant and equipment net, at realizable value	$ 428,804
Other	37,543
	466,347

The results of operations associated with these discontinued operations were as follows:

(Thousands of dollars)	Three Months Ended September 30 2011	2010	Nine Months Ended September 30 2011	2010
Revenues	$ 1,315,229	863,449	3,700,789	2,230,231
Income (loss) before income taxes, including gain on sale of $15,959 in the three-month and nine-month periods in 2011	107,215	7,285	203,601	(11,366)
Income tax expense (benefit)	36,842	1,890	71,170	(5,301)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note E Financing Arrangements

In June 2011, the Company replaced its $1.9 billion committed credit facility that was scheduled to expire in July 2012 with a new five-year $1.5 billion credit facility. Borrowings under the new facility bear interest at 1.5% above LIBOR based on the Company s current credit rating as of September 30, 2011. The new committed facility did not alter the ability of the Company to borrow under other existing credit facilities, nor did it impact its 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.

Ten year notes totaling $350 million, which mature in May 2012, have been classified as Current maturities of long-term debt as of September 30, 2011. Early in the fourth quarter 2011, the Company used cash proceeds from a sale of two U.S. refineries to pay down outstanding loans under existing revolving credit facilities. The balance of revolving debt outstanding at September 30, 2011 was $725.0 million.

Note F Cash Flow Disclosures

Additional disclosures regarding cash flow activities are provided below.

	Nine Months Ended September 30,	
(Thousands of dollars)	2011	2010
Net (increase) decrease in operating working capital other than cash and cash equivalents:		
(Increase) decrease in accounts receivable	$ (314,908)	99,628
(Increase) decrease in inventories	(31,865)	(104,464)
(Increase) decrease in prepaid expenses	(28,693)	(2,045)
(Increase) decrease in deferred income tax assets	4,797	(59,254)
Increase (decrease) in accounts payable and accrued liabilities	185,618	412,015
Increase (decrease) in current income tax liabilities	(124,385)	71,357
Total	$ (309,436)	417,237
Supplementary disclosures:		
Cash income taxes paid	$ 608,065	419,313
Interest paid, net of amounts capitalized	18,124	17,162

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. In conjunction with the sale of the Superior, Wisconsin refinery in September 2011, the purchaser assumed the obligations associated with the defined pension and other postretirement plans covering the refinery s union employees. In conjunction with the sale of the Meraux refinery in October 2011, all benefits associated with the defined pension and other postretirement benefit plans were frozen.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note G Employee and Retiree Benefit Plans ***(Contd.)***

The table that follows provides the components of net periodic benefit expense for the three-month and nine-month periods ended September 30, 2011 and 2010.

	Three Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2011	2010	2011	2010
Service cost	$ 5,915	5,282	1,289	921
Interest cost	7,919	7,480	1,719	1,474
Expected return on plan assets	(6,840)	(5,933)	0	0
Amortization of prior service cost	337	387	(66)	(67)
Amortization of transitional asset	(51)	(127)	3	0
Recognized actuarial loss	2,543	2,995	786	596
	9,823	10,084	3,731	2,924
Termination benefits expense	700	0	0	0
Curtailment expense (gain)	1,105	0	(605)	0
Net periodic benefit expense	$ 11,628	10,084	3,126	2,924

	Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2011	2010	2011	2010
Service cost	$ 17,763	15,738	3,803	2,729
Interest cost	23,855	22,361	5,084	4,379
Expected return on plan assets	(20,634)	(17,675)	0	0
Amortization of prior service cost	1,020	1,158	(196)	(197)
Amortization of transitional asset	(155)	(383)	7	0
Recognized actuarial loss	7,661	8,948	2,326	1,770
	29,510	30,147	11,024	8,681
Termination benefits expense	700	0	0	0
Curtailment expense (gain)	1,105	0	(605)	0
Net periodic benefit expense	$ 31,315	30,147	10,419	8,681

Termination benefits and curtailments in the 2011 periods related to the sales of U.S. refineries in 2011.

During the nine-month period ended September 30, 2011, the Company made contributions of $36.6 million to its defined benefit pension and postretirement benefit plans. Remaining funding in 2011 for the Company s defined benefit pension and postretirement plans is anticipated to be $8.8 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. The Company provides a health care benefit plan to eligible U.S. active and retired employees. The new law did not significantly affect the Company s consolidated financial statements as of September 30, 2011 and 2010 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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.

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. 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.

In February 2011, the Committee granted stock options for 1,397,312 shares at an exercise price of $67.635 per share. The Black-Scholes valuation for these awards was $20.34 per option. The Committee also granted 521,423 performance-based restricted stock units in February 2011 under the 2007 Long-Term Plan. The fair value of the performance-based restricted stock units, using a Monte Carlo valuation model, ranged from $38.94 to $64.89 per unit. Also in February and August 2011, the Committee granted 29,115 shares and 3,596 shares, respectively, of time-based restricted stock 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 $67.64 per share in February and $60.41 per share in August.

Cash received from options exercised under all share-based payment arrangements for the nine-month periods ended September 30, 2011 and 2010 was $8.2 million and $26.1 million, respectively. The actual income tax benefit realized for the tax deductions from option exercises of the share-based payment arrangements totaled $7.4 million and $11.7 million for the nine-month periods ended September 30, 2011 and 2010, respectively.

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

	Nine Months Ended September 30,	
(Thousands of dollars)	2011	2010
Compensation charged against income before tax benefit	$ 32,885	31,594
Related income tax benefit recognized in income	9,883	9,144

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, 2011 and 2010. 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)	2011	2010	2011	2010
Basic method	193,517,785	191,943,813	193,342,825	191,577,000
Dilutive stock options and restricted stock units	893,331	1,494,179	1,206,021	1,289,485

Diluted method	194,411,116	193,437,992	194,548,846	192,866,485

Certain options to purchase shares of common stock were outstanding during the 2011 and 2010 periods but were not included in the computation of diluted EPS because the incremental shares from assumed conversion were antidilutive. These included 1,764,565 shares at a weighted average share price of $69.53 in each 2011 period and 2,237,753 shares at a weighted average share price of $58.79 in each 2010 period.

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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 before income tax expense. For the three-month and nine-month periods in 2011 and 2010, the Company s effective income tax rates were as follows:

	2011	2010
Three months ended September 30	37.2%	44.0%
Nine months ended September 30	41.1%	42.8%

The effective tax rates for the 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; a tax rate increase in 2011 on oil and gas profits in the U.K.; 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. A one-time tax benefit in Malaysia reduced income tax expense in 2011.

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 Company recorded the effect of this tax increase in its consolidated financial statements in the third quarter 2011. The supplemental tax increased income tax expense by $14.5 million for the three-month and nine-month periods ended September 30, 2011. The majority of this impact relates to a third quarter adjustment to increase the carrying value of net deferred tax liabilities associated with U.K. upstream operations. The tax rates for the three-month and nine-month periods in 2010 benefited 0.5% and 0.2%, respectively, for an income tax adjustment in the U.K.

In the third quarter 2011, it was determined that Block P expenditures are deductible against Block K income. 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 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. During the third quarter of 2011, $6.5 million of uncertain tax positions were settled in the U.S. and recorded as a benefit due to a lapse of time related to the statute of limitation. As of September 30, 2011, the earliest years remaining open for audit and/or settlement in our major taxing jurisdictions are as follows: United States 2008; Canada 2006; United Kingdom 2009; 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. As described below, certain interest rate derivative contracts are accounted for as hedges and the gain or loss associated with recording the fair value of these contracts has been deferred in Accumulated Other Comprehensive Income until the anticipated transactions occur.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note K Financial Instruments and Risk Management ***(Contd.)***

Commodity Purchase Price Risks

The Company is subject to commodity price risks related to crude oil feedstocks previously held in inventory at U.S. refineries. The Company had no open crude oil derivative contracts at September 30, 2011. Short-term derivative instruments were outstanding at September 30, 2010 to manage the cost of about 0.9 million barrels of crude oil and other feedstocks at the Company s U.S. refineries. Also, at September 30, 2010, the Company had open derivative contracts covering 0.4 million barrels of intermediate feedstock inventories which were to be processed at the Company s refineries. The total impact of marking to market these contracts decreased income before taxes by $3.8 million in the nine-month period ended September 30, 2010. There was an accounts receivable of $7.3 million related to matured but unsettled crude oil derivative contracts at September 30, 2011.

The Company is also subject to commodity price risk related to corn that it will purchase in the future for feedstock and to wet and dried distillers grain that it will sell in the future at its ethanol production facilities in the United States. At September 30, 2011 and 2010, the Company had open physical delivery fixed-price commitment contracts for purchase of approximately 7.9 million and 5.4 million bushels of corn, respectively, for processing at its ethanol plants. The Company also had outstanding derivative contracts to sell a similar volume of these fixed-price quantities and buy them back at future prices in effect on the expected date of delivery under the purchase commitment contracts. Also, at September 30, 2011, the Company had open physical delivery fixed-price commitment contracts for sale of approximately 1.6 million equivalent bushels of wet and dried distillers grain 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. Additionally, at September 30, 2011, the Company had outstanding derivative contracts to sell 2.3 million bushels of corn and buy them back when certain corn inventories are expected to be processed at the Hereford, Texas facility. The impact of marking to market these commodity derivative contracts increased income before taxes by $1.9 million in the nine-month period ended September 30, 2011 and was insignificant for the nine-month period ended September 30, 2010.

Foreign Currency Exchange Risks

The Company is subject to foreign currency exchange risk associated with operations in countries outside the U.S. Short-term derivative instruments were outstanding at September 30, 2011 and 2010 to manage the risk of certain future income taxes that are payable in Malaysian ringgits. The equivalent U.S. dollars of Malaysian ringgit derivative contracts open at September 30, 2011 and 2010 were approximately $123.3 million and $194.0 million, respectively. Short-term derivative instrument contracts totaling $38.0 million and $107.0 million U.S. dollars were also outstanding at September 30, 2011 and 2010, respectively, 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 before taxes by $4.6 million and $29.7 million for the nine-month periods ended September 30, 2011 and 2010, respectively.

At September 30, 2011 and December 31, 2010, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

	September 30, 2011		December 31, 2010	
(Thousands of dollars)	Asset (Liability) Derivatives		Asset (Liability) Derivatives	
Type of Derivative Contract	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity	Accounts receivable	$ 9,228	Accounts receivable	$ 750
Commodity			Accounts payable	(626)
Foreign exchange	Accounts payable	(2,609)	Accounts receivable	7,261

For the three-month and nine-month periods ended September 30, 2011 and 2010, the gains and losses recognized in the Consolidated Statements of Income for derivative instruments not designated as hedging instruments are presented in the following table.

(Thousands of dollars) Type of Derivative Contract	Statement of Income Location	Gain (Loss) Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Commodity	Crude oil and product purchases	$ 7,381	(1,695)	5,900	(1,085)
Foreign exchange	Interest and other income	(7,376)	13,954	4,614	29,681
		$ 5	12,259	10,514	28,596

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note K Financial Instruments and Risk Management ***(Contd.)***

Interest Rate Risks

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

At September 30, 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.

(Thousands of dollars)	September 30, 2011 Asset (Liability) Derivatives	
Type of Derivative Contract	Balance Sheet Location	Fair Value
Interest rate	Accounts Payable	$ (20,722)

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, 2011 and December 31, 2010 are presented in the following table.

	September 30, 2011				December 31, 2010			
(Thousands of dollars)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Foreign exchange derivative contracts	$ 0	0	0	0	0	7,261	0	7,261
Commodity derivative contracts	0	9,228	0	9,228	0	750	0	750
	$ 0	9,228	0	9,228	0	8,011	0	8,011
Liabilities								
Nonqualified employee savings plans	$ (6,980)	0	0	(6,980)	(7,672)	0	0	(7,672)
Foreign exchange derivative contracts	0	(2,609)	0	(2,609)	0	0	0	0
Commodity derivative contracts	0	0	0	0	0	(626)	0	(626)
Interest rate derivative contracts	0	(20,722)	0	(20,722)	0	0	0	0
	$ (6,980)	(23,331)	0	(30,311)	(7,672)	(626)	0	(8,298)

The fair value of commodity derivative contracts was determined based on market quotes for West Texas Intermediate crude oil and 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. There was no income effect for the change in fair value of interest rate derivative contracts. 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 liability was based on quoted prices for these equity securities and mutual funds. The income effect of changes in the fair value of nonqualified employee savings plan is recorded in Selling and General Expenses.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note L Accumulated Other Comprehensive Income

The components of Accumulated Other Comprehensive Income on the Consolidated Balance Sheets at September 30, 2011 and December 31, 2010 are presented in the following table.

(Thousands of dollars)	Sept. 30, 2011	Dec. 31, 2010
Foreign currency translation gains, net of tax	$ 409,927	587,408
Retirement and postretirement benefit plan losses, net of tax	(124,343)	(137,980)
Loss deferred for fair value of interest rate derivative contracts, net of tax	(13,469)	0
Accumulated other comprehensive income	$ 272,115	449,428

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 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note M Environmental and Other Contingencies ***(Contd.)***

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 this 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 the 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.

Murphy is 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.

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, 2011, the Company had contingent liabilities of $7.8 million under a financial guarantee and $251.5 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 2011 and 2012 natural gas sales volumes in the Tupper and Tupper West areas in Western Canada. The contracts call for natural gas deliveries of approximately 99 million cubic feet per day in the last three months of 2011 at an average price of Cdn$4.90 per MCF, with the contracts calling for delivery at the AECO C sales point. In 2012, contracts call for delivery at AECO C of approximately 50 million cubic feet per day at an average price of Cdn$4.43 per MCF. 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 exist. The Terra Nova redetermination process was essentially completed in 2010, and the Company s working interest at Terra Nova was reduced from its original 12.0% to approximately 10.475%. 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 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 benefit of $5.4 million in the nine-month period ended September 30, 2011 due to the ultimate cost of the redetermination settlement being less than originally estimated. The 2010 expense and 2011 benefit have been reflected as Redetermination of Terra Nova Working Interest in the Consolidated Statements of Income.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note P Accounting Matters

In September 2011, the Financial Accounting Standards Board (FASB) issued an update that is intended to simplify the annual goodwill impairment assessment process by permitting a company to assess whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount before applying the two-step goodwill impairment test. If a company concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the company would be required to conduct the current two-step goodwill impairment test. This change is effective for annual and interim goodwill impairment tests performed in fiscal years beginning after December 15, 2011, but early adoption is permitted. The Company is still evaluating the standard and may choose to early adopt this update for the annual goodwill impairment test due to be performed as of year-end 2011.

The Company adopted new guidance issued by the 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 amended previous guidance for determining whether an entity is considered a variable interest entity. The adoption of this guidance did not have a significant effect on the Company s consolidated financial statements.

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

The United States Congress passed the Dodd-Frank Act in 2010. Among other requirements, the law requires companies in the oil and gas industry to disclose payments made to the U.S. Federal and all foreign governments. The SEC was directed to develop the reporting requirements in accordance with the law. The SEC has issued preliminary guidance and has sought 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 Dodd-Frank Act.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note Q Business Segments

(Millions of dollars)	Total Assets at Sept. 30, 2011	Three Mos. Ended Sept. 30, 2011 External Revenues	Three Mos. Ended Sept. 30, 2011 Inter-segment Revenues	Three Mos. Ended Sept. 30, 2011 Income (Loss)	Three Mos. Ended Sept. 30, 2010[1] External Revenues	Three Mos. Ended Sept. 30, 2010[1] Inter-segment Revenues	Three Mos. Ended Sept. 30, 2010[1] Income (Loss)
Exploration and production[2]							
United States	$ 1,752.7	173.2	0	38.2	155.2	0	14.6
Canada	3,467.6	307.4	42.7	102.3	170.5	33.5	39.1
Malaysia	3,487.0	484.8	0	197.7	453.4	0	167.6
United Kingdom	205.4	20.2	0	(11.5)	28.0	0	4.9
Republic of the Congo	706.0	43.7	0	(.7)	46.6	0	(20.2)
Other	68.9	0	0	(64.1)	.4	0	(19.3)
Total	9,687.6	1,029.3	42.7	261.9	854.1	33.5	186.7
Refining and marketing							
United States	2,241.8	4,629.2	0	88.0	3,424.6	0	59.0
United Kingdom	1,157.4	1,552.1	0	(19.1)	930.5	0	(13.8)
Total	3,399.2	6,181.3	0	68.9	4,355.1	0	45.2
Total operating segments	13,086.8	7,210.6	42.7	330.8	5,209.2	33.5	231.9
Corporate	1,859.3	29.8	0	4.9	(8.9)	0	(34.5)
Assets/revenue/income from continuing operations	14,946.1	7,240.4	42.7	335.7	5,200.3	33.5	197.4
Discontinued operations, net of tax	545.0	0	0	70.4	0	0	5.4
Total	$ 15,491.1	7,240.4	42.7	406.1	5,200.3	33.5	202.8

(Millions of dollars)	Nine Months Ended Sept. 30, 2011 External Revenues	Nine Months Ended Sept. 30, 2011 Inter-segment Revenues	Nine Months Ended Sept. 30, 2011 Income (Loss)	Nine Months Ended Sept. 30, 2010[1] External Revenues	Nine Months Ended Sept. 30, 2010[1] Inter-segment Revenues	Nine Months Ended Sept. 30, 2010[1] Income (Loss)
Exploration and production[2]						
United States	$ 539.7	0	106.8	497.8	0	47.8
Canada	827.7	137.4	284.5	593.9	73.9	150.6
Malaysia	1,442.1	0	559.5	1,386.7	0	499.3
United Kingdom	83.9	0	6.8	109.5	0	29.9
Republic of the Congo	111.4	0	(.4)	100.3	0	(26.6)
Other	24.4	0	(191.6)	3.0	0	(48.2)
Total	3,029.2	137.4	765.6	2,691.2	73.9	652.8
Refining and marketing						
United States	13,356.1	0	172.9	10,083.5	0	135.2
United Kingdom	4,499.0	0	(43.6)	1,889.5	0	(24.4)

Total	17,855.1	0	129.3	11,973.0	0	110.8
Total operating segments	20,884.3	137.4	894.9	14,664.2	73.9	763.6
Corporate	43.7	0	(40.7)	(58.6)	0	(133.5)
Revenue/income from continuing operations	20,928.0	137.4	854.2	14,605.6	73.9	630.1
Discontinued operations, net of tax	0	0	132.4	0	0	(6.1)
Total	$ 20,928.0	137.4	986.6	14,605.6	73.9	624.0

1 Reclassified to conform to current presentation.

2 Additional details about results of oil and gas operations are presented in the tables on pages 26 and 27.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note Q Business Segments *(Contd.)*

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. Beginning in the third quarter 2011, results of operations for the Superior and Meraux refineries and associated marketing assets have been reported as discontinued operations net of taxes for all periods presented in the Consolidated Statement of Income and in the following segment table. Due to the sale of the two U.S. refineries, Company management has reevaluated the reportable segments for the downstream business. Based on this reevaluation, the U.S. downstream is now being presented as one reportable segment while the two refineries that formerly comprised the majority of the former U.S. manufacturing segment are presented in the segment table as discontinued operations. The Company continues to actively market for sale the U.K. downstream assets and expects that the results of these operations to be sold 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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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 2011 was $406.1 million ($2.09 per diluted share) compared to net income of $202.8 million ($1.05 per diluted share) in the third quarter of 2010. The income improvement in 2011 primarily related to higher sales prices for the Company s crude oil production and higher margins on U.S. refining and marketing operations. The 2011 quarter also included net tax benefits of $11.1 million related to oil and gas operations. These factors were partially offset by lower crude oil sales volumes, higher exploration expenses and significantly weaker results in U.K. downstream operations. The Company sold its two U.S. refineries near the end of the third quarter 2011 and has reported results of operations and the 2011 net gain on sale as discontinued operations. The 2011 quarterly net income included income from discontinued operations of $70.4 million ($0.36 per diluted share) compared to income of $5.4 million ($0.03 per diluted share) in the 2010 quarter. The improvement in the 2011 quarter was due to stronger U.S. refinery margins in the current period, coupled with an after-tax gain of $16.9 million upon sale of the two refineries. Income from continuing operations was $335.7 million ($1.73 per diluted share) in the 2011 quarter and $197.4 million ($1.02 per diluted share) in the comparable 2010 quarter.

For the first nine months of 2011, net income totaled $986.6 million ($5.07 per diluted share) compared to net income of $624.0 million ($3.24 per diluted share) for the same period in 2010. The increase in net income in 2011 compared to 2010 was also primarily attributable to higher crude oil sales prices and improved U.S. refining and marketing results. Operating results were unfavorably affected in 2011 by lower crude oil sales volumes, higher exploration expenses and a larger operating loss in U.K. downstream operations. Income from discontinued operations totaled $132.4 million ($0.68 per diluted share) in the nine-month period of 2011, while these results were a loss of $6.1 million ($0.03 loss per diluted share) in 2010. The current year included much stronger U.S. refining margins and a $16.9 million after-tax gain on sale of the refineries. Income from continuing operations in the 2011 and 2010 nine months was $854.2 million ($4.39 per diluted share) and $630.1 million ($3.24 per diluted share), respectively.

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)	2011	2010	2011	2010
Exploration and production	$ 261.9	186.7	765.6	652.8
Refining and marketing	68.9	45.2	129.3	110.8
Corporate	4.9	(34.5)	(40.7)	(133.5)
Income from continuing operations	$ 335.7	197.4	854.2	630.1

In the 2011 third quarter, the Company s exploration and production operations earned $261.9 million compared to $186.7 million in the 2010 quarter. Income in the 2011 quarter was favorably impacted compared to 2010 by higher crude oil sales prices, higher natural gas sales volumes, and an $11.1 million net income tax benefit. Exploration expenses were $85.7 million in the third quarter of 2011 compared to $62.0 million in the same period of 2010. The Company s refining and marketing operations generated income from continuing operations of $68.9 million in the 2011 third quarter compared to $45.2 million in the same quarter of 2010. U.S. retail marketing margins improved in the 2011 quarter, compared to the 2010 quarter, but refining and marketing results in the U.K. were unfavorable to the prior year. The Company sold its two U.S. refineries near the end of third quarter 2011 and has reported all periods presented for these U.S. refining assets as discontinued operations. The corporate function had after-tax benefits of $4.9 million in the 2011 third quarter compared to after-tax costs of $34.5 million in the 2010 period with the favorable variance in 2011 mostly due to gains on transactions denominated in foreign currencies in 2011 compared to losses on such transactions in the 2010 quarter.

In the first nine months of 2011, the Company s exploration and production operations earned $765.6 million compared to $652.8 million in the same period of 2010. Earnings in 2011 compared favorably to the 2010 period primarily due to higher realized crude oil sales prices and higher natural gas sales volumes. Exploration expenses increased from $181.5 million in the first nine months of 2010 to $304.5 million in the 2011 period, with the higher costs in 2011 primarily from unsuccessful wildcat drilling offshore Indonesia, Suriname and Brunei. The Company s refining and marketing continuing operations had earnings of $129.3 million in the first nine months of 2011 compared to earnings of $110.8 million in the same 2010 period. The 2011 period included stronger results in the U.S. retail marketing business compared to a year ago based on better operating margins. However, losses from U.K. refining and marketing operations were significantly higher in 2011 compared to 2010 due to more sales volumes at very

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

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

weak operating margins. Corporate after-tax costs were $40.7 million in the 2011 period compared to after-tax costs of $133.5 million in the 2010 period. The current period had a favorable impact from gains on transactions denominated in foreign currencies, while the prior year included significant losses from these transactions.

Exploration and Production

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

	Income (Loss)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(Millions of dollars)	2011	2010	2011	2010
Exploration and production				
United States	$ 38.2	14.6	106.8	47.8
Canada	102.3	39.1	284.5	150.6
Malaysia	197.7	167.6	559.5	499.3
United Kingdom	(11.5)	4.9	6.8	29.9
Republic of the Congo	(0.7)	(20.2)	(0.4)	(26.6)
Other International	(64.1)	(19.3)	(191.6)	(48.2)
Total	$ 261.9	186.7	765.6	652.8

Third quarter 2011 vs. 2010

United States exploration and production operations had earnings of $38.2 million in the third quarter of 2011 compared to earnings of $14.6 million in the 2010 quarter. Earnings improved in the 2011 period primarily due to higher realized oil sales prices. Oil and natural gas production volumes were lower in 2011 due to decline at Thunder Hawk and other fields in the Gulf of Mexico. A significant portion of this production decline was attributable to an inability to obtain drilling permits in the Gulf of Mexico following the Macondo incident in April 2010. Also, production in the Gulf of Mexico was unfavorably affected by about six days of downtime at several fields due to a tropical storm in September 2011. Production expenses increased $6.9 million in 2011 compared to 2010 mostly due to higher production in the Eagle Ford Shale area of South Texas. Depreciation expense was $25.7 million less in 2011 due to lower oil and natural gas production volumes and lower per-barrel capital amortization rates in the Gulf of Mexico in the current quarter. Exploration expenses in the 2011 quarter were $2.4 million lower due to less leasehold amortization for oil fields now being developed in the Eagle Ford Shale area, partially offset by higher seismic costs in the Eagle Ford Shale. Selling and general expenses in the 2011 period increased $1.1 million from the prior year primarily due to higher costs for employee compensation and other professional services.

Operations in Canada had earnings of $102.3 million in the third quarter 2011 compared to earnings of $39.1 million in the 2010 quarter. Canadian earnings increased in the 2011 quarter mostly due to higher crude oil and natural gas sales prices and higher oil and natural gas sales volumes. Oil production increased in the 2011 period compared to 2010 primarily due to a combination of higher volumes at Syncrude due to less downtime for maintenance during the current quarter and higher heavy oil production at Seal due to expanded drilling activities. Natural gas volumes increased in 2011 due to start-up of Tupper West area production in February 2011 and higher volumes produced at the nearby Tupper Main area. Production and depreciation expenses for conventional oil operations in Canada were unfavorable in 2011 by $20.7 million and $33.4 million, respectively, due primarily to higher gas volumes produced at Tupper West and Tupper Main. Production expenses at Syncrude increased $6.3 million in 2011 due to higher fuel and maintenance costs. Depreciation expense increased by $2.7 million at Syncrude in 2011 due to higher oil production volumes. The 2010 quarter included expense of $4.5 million related to a required working redetermination at the Terra Nova field, offshore Newfoundland. Selling and general expenses increased $1.5 million in 2011 due to higher employee compensation and office costs.

Operations in Malaysia reported earnings of $197.7 million in the 2011 quarter compared to earnings of $167.6 million during the same period in 2010. Earnings rose in 2011 in Malaysia from a combination of higher crude oil sales prices, higher natural gas sales prices and sales volumes from fields offshore Sarawak, and favorable income tax benefits. The 2011 quarter was unfavorably affected by lower crude oil sales volumes, primarily at the Kikeh field where certain wells were shut-in or curtailed for rig workovers. An active workover program is ongoing at Kikeh and early results have been successful. Production expenses were higher in the 2011 period by $29.5 million primarily

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

Results of Operations *(Contd.)*

Exploration and Production (Contd.)

Third quarter 2011 vs. 2010 (Contd.)

due to the workover costs at the Kikeh field. Depreciation expense was $11.2 million less in the 2011 quarter due to lower crude oil sales volumes, somewhat offset by higher natural gas sales volumes. Exploration expense was $2.8 million higher in 2011 due to the cost of 3D seismic acquired in Block H, offshore Sabah. An income tax benefit of $25.6 million was recorded in the third quarter 2011 associated with 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 previously not recognized income tax benefits of Block P costs.

United Kingdom operations had a net loss of $11.5 million in the 2011 quarter compared to earnings of $4.9 million in the 2010 quarter. The lower operating results were primarily due to unfavorable income tax adjustments in the 2011 quarter, coupled with lower sales volumes for crude oil and natural gas. These variances were partially offset by higher crude oil and natural gas sales prices and lower exploration expenses in the current quarter. The lower crude oil and natural gas sales volumes were mostly caused by maintenance undertaken at North Sea fields during the summer months of 2011. Production expense was $2.9 million more in 2011 than 2010 due to higher maintenance costs in the current quarter at the Schiehallion and Mungo/Monan fields. Depreciation expense declined by $3.4 million in 2011 compared to 2010 primarily due to lower oil and gas sales volumes. Exploration expenses were $5.6 million less in the 2011 quarter compared to 2010, principally due to an unsuccessful exploratory well drilled in the prior year. An income tax charge of $14.5 million was recognized in the 2011 third quarter associated with a 12% tax rate increase on oil and gas company profits, which was enacted by the U.K. government during the quarter retroactive to April 2011. The tax charge was primarily associated with an increase of recorded deferred tax liabilities. Henceforth, the statutory tax rate is 62% for U.K. exploration and production operations.

Operations in Republic of the Congo incurred a loss of $0.7 million in the third quarter of 2011 compared to a loss of $20.2 million in the 2010 quarter. Results improved in the current period primarily due to lower exploration expenses and higher crude oil sales prices. Production expense declined by $9.8 million in 2011 versus 2010 due to less well maintenance costs at the Azurite field. Depreciation expense increased by $0.9 million in 2011 associated with a higher unit rate for capital amortization. Exploration expenses were $13.8 million less in the 2011 third quarter compared to 2010 as the prior year included costs for 3D seismic acquired over a portion of the offshore MPN and MPS blocks.

Other international operations reported a loss of $64.1 million in the third quarter of 2011 compared to a loss of $19.3 million in the 2010 period. The unfavorable variance in the current quarter included higher unsuccessful exploratory drilling costs in Brunei, higher seismic costs covering licenses offshore Brunei, and higher geophysical and lease amortization costs associated with exploration licenses in the Kurdistan Region of Iraq.

On a worldwide basis, the Company s crude oil, condensate and gas liquids prices averaged $95.95 per barrel in the third quarter 2011 compared to $65.45 in the 2010 period. Total hydrocarbon production averaged 174,801 barrels of oil equivalent per day in the 2011 third quarter, down from the 181,733 barrels equivalent per day produced in the 2010 quarter. Average crude oil and liquids production was 96,437 barrels per day in the third quarter of 2011 compared to 119,899 barrels per day in the third quarter of 2010, with the reduction primarily attributable to lower gross oil production at the Kikeh field caused by wells shut-in or curtailed for rig workovers. U.S. crude oil production in the 2011 third quarter was down from 2010 mostly at the Thunder Hawk field, where development drilling has been delayed by the protracted process required to obtain drilling permits in the Gulf of Mexico following the Macondo incident in 2010. Canadian offshore crude oil production at Terra Nova was lower in the 2011 quarter due to curtailed production associated with equipment constraints on the production facility. Canadian crude oil production in the heavy oil area was higher in 2011 mostly due to more drilling activity in the Seal area in the current year. Synthetic crude oil production was higher in 2011 due to less downtime for maintenance in the current quarter. Oil production in the U.K. was lower in 2011 due to more downtime for maintenance at North Sea fields during the summer, and oil production in the Republic of Congo was lower in 2011 due to Azurite field well decline. North American natural gas sales prices averaged $4.20 per thousand cubic feet (MCF) in the 2011 quarter compared to $4.24 per MCF in the same quarter of 2010. Natural gas produced in 2011 at fields offshore Sarawak was sold at $7.54 per MCF, compared to a sale price of $5.71 per MCF in the 2010 quarter. Natural gas sales volumes averaged 470 million cubic feet per day in the third quarter 2011, up from 371 million cubic feet per day in the 2010 quarter. The increase

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

Results of Operations *(Contd.)*

Exploration and Production (Contd.)

Third quarter 2011 vs. 2010 (Contd.)

in natural gas sales volumes in 2011 was primarily due to start-up of Tupper West area production in British Columbia in February 2011. The Company also had higher natural gas production at nearby Tupper Main as development drilling operations continued in 2011, and also had higher gas production from fields offshore Sarawak due to higher customer demand and more consistent operations.

Nine months 2011 vs. 2010

U.S. E&P operations had income of $106.8 million for the nine months ended September 30, 2011 compared to income of $47.8 million in the 2010 period. The 2011 period benefited from higher crude oil sales prices, but natural gas sales prices were lower in the 2011 period compared to the prior year. Crude oil and natural gas production volumes were lower in 2011 primarily due to declines at fields in the Gulf of Mexico, which were mostly caused by delays in obtaining drilling permits following the Macondo incident. Production expense was $17.9 million more in 2011 than 2010 mostly due to higher production in the Eagle Ford Shale area of South Texas. Depreciation expense was $89.9 million less in 2011 than 2010 due to the lower overall production volumes and a lower per-barrel capital amortization rate. Exploration expense in the 2011 period was $10.3 million above 2010 levels primarily due to higher Eagle Ford Shale area geophysical expense and undeveloped lease amortization. Selling and general expenses rose by $8.1 million in 2011 compared to 2010 essentially due to higher costs for employee compensation and other professional services.

Canadian operations had income of $284.5 million in the first nine months of 2011 compared to income of $150.6 million a year ago. Higher sales prices for crude oil and higher volumes of natural gas sold were the primary drivers to the improvement in 2011 earnings. Production and depreciation expenses increased $60.3 million and $71.6 million, respectively, in 2011 mostly related to higher volumes of natural gas produced at the Tupper West area following start-up in February 2011 and higher maintenance costs and production volumes at Syncrude oil operations. A required redetermination of working interest at the Terra Nova field, offshore Newfoundland, led to net costs of $15.4 million in the 2010 period, but the 2011 period included a benefit of $5.4 million associated with the early 2011 final settlement being less costly than previously projected. Selling and general expenses increased by $1.6 million in 2011 due to higher compensation and other office costs.

Malaysia operations earned $559.5 million in the first nine months of 2011 compared to earnings of $499.3 million in the 2010 period. Earnings were stronger in 2011 primarily due to higher crude oil sales prices, a $25.6 million income tax benefit, and higher sales volumes and sales prices for natural gas produced offshore Sarawak. Crude oil sales volumes at the Kikeh field were lower in 2011 than 2010 due to less gross oil production caused by certain wells shut-in or curtailed for rig workovers. Production expense in 2011 exceeded the 2010 cost by $63.2 million primarily due to higher Kikeh field maintenance. Depreciation expense in 2011 was $36.3 million below the 2010 period due to lower oil sales volumes at the Kikeh field. Exploration expense was $22.9 million lower in 2011 mostly due to no repeat of unsuccessful exploration drilling costs incurred in Block H in 2010, but 2011 included higher geophysical costs for 3D seismic acquisition and processing in Block H. The aforementioned income tax benefit arose because it was determined that Block P costs are deductible against taxable earnings from Block K.

Income in the U.K. for the nine-month period in 2011 was $6.8 million compared to $29.9 million a year ago. The earnings reduction in 2011 was primarily due to lower crude oil and natural gas sales volumes and an income tax charge associated with a tax rate increase. The 2011 period benefited from higher crude oil and natural gas sales prices and lower exploration expense compared to 2010. Production expense in 2011 exceeded 2010 levels by $3.2 million primarily due to higher maintenance costs at offshore fields in the current period. Depreciation expense for 2011 was $9.2 million less than in 2010 due to the lower crude oil and natural gas sales volumes. Exploration expense in 2011 was $5.8 million below 2010 due to an unsuccessful exploration well in the prior year. The U.K. government enacted a 12% tax rate increase for oil and gas profits during the third quarter 2011. The rate increase was retroactive to April 2011. The $14.5 million tax charge primarily related to an increase in recorded deferred tax liabilities. The statutory income tax rate for the U.K. oil and gas operations is now 62%.

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

Results of Operations (*Contd.)*

Exploration and Production (Contd.)

Nine months 2011 vs. 2010 (Contd.)

Operations in Republic of the Congo had a loss of $0.4 million for the nine-month 2011 period, compared to a loss of $26.6 million in the 2010 period. The improvement in 2011 was primarily due to higher sales prices for oil produced at the offshore Azurite field and lower exploration expenses. The 2011 period benefited from lower production expenses by $19.5 million due to less well maintenance costs and lower sales volumes in the current period. Depreciation expense increased $16.6 million due to a higher capital amortization rate and higher sales volumes at the Azurite oil field. Exploration expense was $12.3 million lower in 2011 than 2010. The prior year included higher costs for a 3D seismic acquisition covering a portion of the offshore MPN and MPS blocks. Selling and general expense in 2011 was $1.9 million above 2010 levels due to lower overhead amounts chargeable to drilling operations in the current period.

Other international operations reported a loss of $191.6 million in the first nine months of 2011 compared to a loss of $48.2 million in the 2010 period. The higher 2011 loss primarily related to higher costs of $115.5 million associated with unsuccessful offshore wildcat drilling in Indonesia, Suriname and Brunei in the current year. Higher geophysical expense of $20.3 million in 2011 was primarily related to 3D seismic acquired offshore Brunei and studies on exploration licenses in the Central Dohuk and Baranan areas in the Kurdistan Region of Iraq. Higher undeveloped leasehold amortization of $13.2 million in 2011 compared to 2010 was attributable to the new exploration licenses in the Kurdistan Region of Iraq. Other exploration expenses increased $3.3 million in 2011 due to higher costs at various exploration field offices. Selling and general expenses were $4.4 million higher in 2011 primarily due to higher office costs supporting international E&P operations. The 2011 period included an after-tax gain of $13.1 million attributable to sale of the Company s gas storage assets in Spain.

For the first nine months of 2011, the Company s sales price for crude oil, condensate and gas liquids averaged $94.36 per barrel, up from $65.06 per barrel in 2010. Total worldwide production averaged 175,776 barrels of oil equivalent per day during the nine months ended September 30, 2011, down from 189,250 barrels of oil equivalent produced in the same period in 2010. Crude oil, condensate and gas liquids production in the first nine months of 2011 averaged 101,269 barrels per day compared to 130,244 barrels per day a year ago. The reduction was mostly attributable to lower gross oil production at the Kikeh field offshore Sabah Malaysia, where wells were shut-in or curtailed for rig workovers. Crude oil production in the U.S. was lower in 2011 than 2010, primarily at the Thunder Hawk field where development drilling operations have been delayed by the inability to obtain timely drilling permits at the Gulf of Mexico field following the Macondo incident in 2010. Crude oil production offshore eastern Canada was lower in 2011 due to curtailment associated with equipment constraints on the Terra Nova production facility. Crude oil production in the U.K. was lower in 2011 than 2010 due to field decline at Mungo/Monan and more downtime for equipment repairs at Schiehallion. Synthetic oil production at Syncrude increased in 2011 compared to 2010 due to higher gross production. Crude oil produced in Republic of the Congo increased in 2011 due to a new well coming onstream. Heavy Canadian crude oil production in 2011 increased due to ongoing development drilling operations in the Seal area of Alberta. The average sales price for North American natural gas in the first nine months of 2011 was $4.26 per MCF, down from $4.48 per MCF realized in 2010. Natural gas production at fields offshore Sarawak was sold at an average price of $6.76 per MCF in 2011 compared to $5.20 per MCF in 2010. Natural gas sales volumes increased from 354 million cubic feet per day in 2010 to 447 million cubic feet per day in 2011, with the increase mostly due to start-up of natural gas production volumes at the Tupper West area in British Columbia, which came onstream in February 2011, coupled with higher production at nearby Tupper Main and higher volumes produced at offshore Sarawak, Malaysia fields. Natural gas sales volumes from the Kikeh field were lower in 2011 than 2010 due to a combination of wells shut-in or curtailed for workovers and lower customer demand for gas production volumes.

Additional details about results of oil and gas operations are presented in the tables on pages 26 and 27.

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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, 2011 and 2010 follow.

Exploration and Production	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Net crude oil, condensate and gas liquids produced barrels per day	96,437	119,899	101,269	130,244
United States	16,388	19,404	16,750	20,594
Canada light	107	47	74	43
heavy	7,097	5,749	6,875	6,048
offshore	9,758	10,534	9,284	11,774
synthetic	14,022	12,044	13,878	12,973
Malaysia	42,976	63,794	46,684	70,444
United Kingdom	1,502	2,831	2,313	3,669
Republic of Congo	4,587	5,496	5,411	4,699
Net crude oil, condensate and gas liquids sold barrels per day	93,394	122,574	98,663	133,304
United States	16,388	19,404	16,750	20,594
Canada light	107	47	74	43
heavy	7,097	5,749	6,875	6,048
offshore	10,262	10,055	9,381	11,682
synthetic	14,022	12,044	13,878	12,973
Malaysia	39,329	64,547	45,374	72,428
United Kingdom	1,643	3,394	2,371	4,742
Republic of Congo	4,546	7,334	3,960	4,794
Net natural gas sold thousands of cubic feet per day	470,183	371,005	447,044	354,038
United States	38,790	56,159	47,789	52,582
Canada	210,735	81,869	174,635	83,179
Malaysia Sarawak	181,265	167,773	176,067	150,973
Kikeh	36,291	59,538	44,147	61,559
United Kingdom	3,102	5,666	4,406	5,745
Total net hydrocarbons produced equivalent barrels per day (1)	174,801	181,733	175,776	189,250
Total net hydrocarbons sold equivalent barrels per day (1)	171,758	184,408	173,170	192,310
Weighted average sales prices Crude oil, condensate and natural gas liquids dollars per barrel (2)				
United States	$ 102.05	73.10	102.33	74.53
Canada (3) light	90.24	68.33	93.85	73.75
heavy	49.78	46.09	55.08	49.29
offshore	112.47	75.52	110.08	75.29
synthetic	101.18	74.80	103.08	76.04
Malaysia (4)	93.85	60.35	89.86	58.90
United Kingdom	113.82	77.22	110.51	76.53
Republic of the Congo	104.43	70.73	103.05	71.09
Natural gas dollars per thousand cubic feet				
United States (2)	$ 4.36	4.51	4.32	4.75
Canada (3)	4.17	4.05	4.24	4.31

Malaysia	Sarawak	7.54	5.71	6.76	5.20
	Kikeh	0.23	0.23	0.24	0.23
United Kingdom (3)		10.06	7.24	10.00	6.33

(1) Natural gas converted on an energy equivalent basis of 6:1.
(2) Includes intracompany transfers at market prices.
(3) U.S. dollar equivalent.
(4) Prices are net of payments under the terms of the production sharing contracts for Blocks SK 309 and K.

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

Results of Operations *(Contd.)*

OIL AND GAS OPERATING RESULTS THREE MONTHS ENDED SEPTEMBER 30, 2011 AND 2010

(Millions of dollars)	United States	Canada Conven-tional	Canada Syn-thetic	Malaysia	United King-dom	Republic of the Congo	Other	Total
Three Months Ended September 30, 2011								
Oil and gas sales and other operating revenues	$ 173.2	219.6	130.5	484.8	20.2	43.7		1,072.0
Production expenses	41.4	43.7	59.2	116.5	9.3	11.4		281.5
Depreciation, depletion and amortization	40.8	75.1	13.5	83.0	1.6	26.7	.5	241.2
Accretion of asset retirement obligations	2.5	1.2	1.8	2.7	.7	.1	.1	9.1
Exploration expenses								
Dry holes							13.3	13.3
Geological and geophysical	3.8	.9		3.7	.1	.9	24.5	33.9
Other	.8	.3			.1		7.2	8.4
	4.6	1.2		3.7	.2	.9	45.0	55.6
Undeveloped lease amortization	14.0	7.4					8.7	30.1
Total exploration expenses	18.6	8.6		3.7	.2	.9	53.7	85.7
Selling and general expenses	10.4	3.9	.3	(1.1)	.7	.5	9.9	24.6
Results of operations before taxes	59.5	87.1	55.7	280.0	7.7	4.1	(64.2)	429.9
Income tax provisions (benefits)	21.3	26.9	13.6	82.3	19.2	4.8	(.1)	168.0
Results of operations (excluding corporate overhead and interest)	$ 38.2	60.2	42.1	197.7	(11.5)	(.7)	(64.1)	261.9
Three Months Ended September 30, 2010								
Oil and gas sales and other operating revenues	$ 155.2	121.0	83.0	453.4	28.0	46.6	.4	887.6
Production expenses	34.5	23.0	52.9	87.0	6.4	21.2		225.0
Depreciation, depletion and amortization	66.5	41.7	10.8	94.2	5.0	25.8	.4	244.4
Accretion of asset retirement obligations	1.8	1.2	1.5	2.5	.6	.1	.2	7.9
Exploration expenses								
Dry holes	(.2)				5.7	(.3)		5.2
Geological and geophysical	2.1	.1		.9	.1	15.0	3.3	21.5
Other	.6	.1					6.2	6.9
	2.5	.2		.9	5.8	14.7	9.5	33.6
Undeveloped lease amortization	18.5	8.7					1.2	28.4
Total exploration expenses	21.0	8.9		.9	5.8	14.7	10.7	62.0
Terra Nova working interest redetermination		4.5						4.5
Selling and general expenses	9.3	2.4	.3	.3	.7	(.5)	8.4	20.9
Results of operations before taxes	22.1	39.3	17.5	268.5	9.5	(14.7)	(19.3)	322.9

Income tax provisions	7.5	12.7	5.0	100.9	4.6	5.5		136.2
Results of operations (excluding corporate overhead and interest)	$ 14.6	26.6	12.5	167.6	4.9	(20.2)	(19.3)	186.7

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

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

OIL AND GAS OPERATING RESULTS NINE MONTHS ENDED SEPTEMBER 30, 2011 AND 2010

		Canada			United	Republic		
(Millions of dollars)	United States	Conven-tional	Syn-thetic	Malaysia	King-dom	of the Congo	Other	Total
Nine Months Ended September 30, 2011								
Oil and gas sales and other operating revenues	$ 539.7	574.8	390.3	1,442.1	83.9	111.4	24.4	3,166.6
Production expenses	118.9	112.0	176.0	304.3	23.8	28.2		763.2
Depreciation, depletion and amortization	132.1	199.3	40.1	254.7	9.9	64.5	1.3	701.9
Accretion of asset retirement obligations	7.4	3.7	5.7	8.0	2.3	.4	.3	27.8
Exploration expenses								
Dry holes	.6					2.9	115.1	118.6
Geological and geophysical	24.4	3.4		9.5	.4	2.5	27.0	67.2
Other	8.1	.9			.3	.1	18.7	28.1
	33.1	4.3		9.5	.7	5.5	160.8	213.9
Undeveloped lease amortization	52.3	21.4					16.9	90.6
Total exploration expenses	85.4	25.7		9.5	.7	5.5	177.7	304.5
Terra Nova working interest redetermination		(5.4)						(5.4)
Selling and general expenses	30.8	10.5	.7	(1.1)	2.4	.8	28.0	72.1
Results of operations before taxes	165.1	229.0	167.8	866.7	44.8	12.0	(182.9)	1,302.5
Income tax provisions	58.3	68.6	43.7	307.2	38.0	12.4	8.7	536.9
Results of operations (excluding corporate overhead and interest)	$ 106.8	160.4	124.1	559.5	6.8	(.4)	(191.6)	765.6
Nine Months Ended September 30, 2010								
Oil and gas sales and other operating revenues	$ 497.8	397.1	270.7	1,386.7	109.5	100.3	3.0	2,765.1
Production expenses	101.0	75.3	152.4	241.1	20.6	47.7		638.1
Depreciation, depletion and amortization	222.0	134.8	33.0	291.0	19.1	47.9	1.0	748.8
Accretion of asset retirement obligations	5.2	3.6	4.7	7.2	1.7	.2	.4	23.0
Exploration expenses								
Dry holes	(.1)			30.5	5.7	(.6)	(.5)	35.0
Geological and geophysical	19.2	.6		1.9	.6	18.4	6.7	47.4
Other	6.3	.3			.2		15.5	22.3
	25.4	.9		32.4	6.5	17.8	21.7	104.7
Undeveloped lease amortization	49.7	23.4					3.7	76.8
Total exploration expenses	75.1	24.3		32.4	6.5	17.8	25.4	181.5
Terra Nova working interest redetermination		15.4						15.4
Selling and general expenses	22.7	8.9	.7	.6	2.3	(1.1)	23.6	57.7

Results of operations before taxes	71.8	134.8	79.9	814.4	59.3	(12.2)	(47.4)	1,100.6
Income tax provisions	24.0	41.3	22.8	315.1	29.4	14.4	.8	447.8
Results of operations (excluding corporate overhead and interest)	$ 47.8	93.5	57.1	499.3	29.9	(26.6)	(48.2)	652.8

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

Results of Operations (*Contd.)*

Refining and Marketing

Third Quarter 2011 vs. 2010

In 2010, the Company announced its intention to sell its three refineries and U.K. marketing operations during 2011. The Company completed the sale of the Superior, Wisconsin refinery and associated marketing assets on September 30, 2011. Also, the Company sold the Meraux, Louisiana refinery and associated marketing assets on October 1, 2011. The assets and liabilities of the Meraux refinery sold in the fourth quarter are reported as held for sale in the Consolidated Balance Sheet as of September 30, 2011. The revenues and expenses for both refineries for all periods presented have been reclassified to discontinued operations, net of tax, in the Consolidated Statements of Income. The sale process for the U.K. downstream operations continues to progress. See Note D in the consolidated financial statements for further discussion.

United States refining and marketing includes two ethanol production facilities along with retail and wholesale fuel marketing operations. The United Kingdom refining and marketing segment includes the Milford Haven, Wales, refinery and U.K. retail and other refined products marketing operations.

Murphy s downstream income from continuing operations is presented below by segment.

	Income (Loss)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(Millions of dollars)	2011	2010	2011	2010
Refining and marketing continuing operations				
United States	$ 88.0	59.0	172.9	135.2
United Kingdom	(19.1)	(13.8)	(43.6)	(24.4)
Total	$ 68.9	45.2	129.3	110.8

United States downstream earnings from continuing operations increased from $59.0 million in the 2010 third quarter to $88.0 million in 2011. The U.S. retail marketing business generated virtually all of the increased income for U.S. operations in the current quarter. The favorable 2011 result was primarily due to an improvement in U.S. retail marketing margins, which totaled $0.200 per gallon in 2011 and $0.137 per gallon in 2010. In addition, these U.S. retail operations generated higher profits from merchandise sales in the 2011 quarter. However, overall per-store retail fuel sales volumes in the current period were below 2010 levels by about 11%. Earnings from ethanol production operations were flat between periods, primarily due to decreased margins at the Hankinson, North Dakota plant essentially offset by a full quarter of operations at the Hereford, Texas plant in the current year. The ramp-up of production at the Hereford plant after start-up has met Company expectations.

Refining and marketing operations in the United Kingdom had a net loss of $19.1 million in the third quarter of 2011 compared to a net loss of $13.8 million in the same quarter of 2010. The U.K. results in 2011 were unfavorably affected compared to 2010 by higher administrative expenses in the current quarter and a nonrecurring income tax benefit in 2010 for a 1% reduction in corporate tax rates. Crude oil throughput volumes at the Milford Haven refinery were 135,053 barrels per day during the 2011 quarter, significantly ahead of throughputs of 105,522 barrels per day in the 2010 quarter. A capital project completed during a 2010 turnaround expanded the crude oil throughput capacity of the Milford Haven refinery from 108,000 to 135,000 barrels per day.

Worldwide petroleum product sales (including discontinued operations) were 594,619 barrels per day in the 2011 quarter, up from 584,306 barrels per day a year ago. This increase was mostly due to the aforementioned higher crude oil throughputs in 2011 at the Milford Haven refinery.

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

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

Refining and Marketing (Contd.)

Nine months 2011 vs. 2010

The United States downstream continuing operations generated income of $172.9 million in the first nine months of 2011 compared to $135.2 million in the 2010 period. U.S. marketing operations generated essentially all of the increase in income in 2011. The favorable result in 2011 was primarily due to U.S. retail marketing margins which improved to $0.165 per gallon in 2011 following a margin of $0.128 per gallon in 2010. In addition, these U.S. retail operations generated higher profits from merchandise sales in 2011 due to capturing slightly more margin on these sales. However, overall per-store fuel sales volumes for the retail operations in the 2011 period were below 2010 levels by about 9%. Ethanol production operations generated lower income in the first nine months of 2011 compared to the same period in 2010. The reduction in 2011 was primarily attributable to unprofitable operations during start-up of the Hereford, Texas plant during the 2011 second quarter in conjunction with decreased margins at the Hankinson, North Dakota plant in the current year as ethanol sales prices did not keep pace with higher corn costs.

Refining and marketing operations in the United Kingdom had a net loss of $43.6 million in the 2011 nine months compared to a net loss of $24.4 million in the same 2010 period. The U.K. results in 2011 were hurt by continued weak refining margins. Although refining margins were somewhat better in 2011 than 2010, higher crude oil throughputs at the Milford Haven, Wales, refinery led to larger volumes of products sold into the weak pricing market, generating a larger overall loss in the current year. Crude oil throughput volumes at Milford Haven were 130,986 barrels per day in 2011, up from 70,729 barrels per day in 2010, as the plant was shut down for turnaround for several months in 2010.

Total petroleum product sales (including discontinued operations) were 586,928 barrels per day in the 2011 period, up from 524,092 barrels per day a year ago. This increase was also mostly due to the aforementioned refinery turnaround at Milford Haven during the prior year.

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

Results of Operations *(Contd.)*

Selected operating statistics for the three-month and nine-month periods ended September 30, 2011 and 2010 follow.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Refinery inputs barrels per day	314,348	267,988	307,714	215,285
United States discontinued operations	176,307	158,002	173,368	140,022
Crude oil Meraux, Louisiana	135,991	111,543	133,918	99,333
Superior, Wisconsin	36,426	36,568	35,407	34,050
Other feedstocks	3,890	9,891	4,043	6,639
United Kingdom	138,041	109,986	134,346	75,263
Crude oil Milford Haven, Wales	135,053	105,552	130,986	70,729
Other feedstocks	2,988	4,434	3,360	4,534
Refinery yields barrels per day	314,348	267,988	307,714	215,285
United States discontinued operations	176,307	158,002	173,368	140,022
Gasoline	67,596	62,873	69,457	57,616
Kerosine	14,244	8,950	14,937	9,973
Diesel and home heating oils	50,382	46,542	50,435	38,519
Residuals	18,871	19,105	17,028	18,420
Asphalt	22,203	18,684	19,844	14,352
Fuel and loss	3,011	1,848	1,667	1,142
United Kingdom	138,041	109,986	134,346	75,263
Gasoline	34,496	29,697	32,670	18,831
Kerosine	17,459	15,326	17,183	10,683
Diesel and home heating oils	46,714	34,503	46,360	22,179
Residuals	15,048	10,447	13,862	7,207
Asphalt	21,049	16,354	21,183	13,471
Fuel and loss	3,275	3,659	3,088	2,892
Petroleum products sold barrels per day	594,619	584,306	586,928	524,092
Total United States	457,729	467,119	451,644	445,897
United States Manufacturing discontinued operations	183,997	160,902	174,618	141,523
Gasoline	80,983	70,328	80,479	65,018
Kerosine	14,245	8,952	14,937	9,973
Diesel and home heating oils	51,161	46,542	50,433	38,519
Residuals	18,424	18,516	16,870	18,151
Asphalt, LPG and other	19,184	16,564	11,899	9,862
United States Marketing	419,375	432,039	422,531	417,884
Gasoline	320,520	339,956	323,812	330,194
Kerosine	15,014	10,968	14,929	9,986
Diesel and other	83,841	81,115	83,790	77,704
United States Intercompany Elimination	(145,643)	(125,822)	(145,505)	(113,510)
Gasoline	(80,983)	(70,328)	(80,479)	(65,018)
Kerosine	(14,244)	(8,952)	(14,937)	(9,973)
Diesel and other	(50,416)	(46,542)	(50,089)	(38,519)
United Kingdom	136,890	117,187	135,284	78,195
Gasoline	36,643	30,389	34,459	21,005
Kerosine	18,625	15,587	16,961	10,765
Diesel and home heating oils	47,614	38,572	47,409	26,496

Residuals	14,493	11,786	14,526	7,414
LPG and other	19,515	20,853	21,929	12,515
Unit margins per barrel:				
United States refining [1] discontinued operations	$ 4.82	0.23	3.45	(0.68)
United Kingdom refining and marketing	(1.66)	(1.84)	(1.37)	(1.75)
United States retail marketing:				
Fuel margin per gallon [2]	$ 0.200	0.137	0.165	0.128
Gallons sold per store month	279,997	313,140	278,442	307,276
Merchandise sales revenue per store month	$ 164,953	161,352	158,385	152,875
Merchandise margin as a percentage of merchandise sales	13.1%	13.5%	13.2%	13.0%
Store count at end of period (Company operated)	1,120	1,083	1,120	1,083

1 Represents refinery sales realizations less cost of crude and other feedstocks and refinery operating and depreciation expenses.

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

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

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

Corporate

Corporate activities, which include interest income and expense, foreign exchange effects, and corporate overhead not allocated to operating functions, had after-tax benefits of $4.9 million in the 2011 third quarter compared to after-tax costs of $34.5 million in the third quarter of 2010. The 2011 results of corporate activities were favorable to 2010 primarily due to net after-tax benefits of $28.3 million on transactions denominated in foreign currencies in the current quarter compared to net after-tax costs of $15.8 million in the comparable 2010 period. The current period foreign currency benefit was primarily attributable to a weakening of the Malaysian ringgit against the U.S. dollar, which led to a reduction of income tax liabilities that are to be paid in the local currency. Partially offsetting the favorable effects of foreign currencies, Corporate activities included higher administrative costs, mostly attributable to employee compensation, and higher net interest expense, associated with both higher average borrowings and lower amounts of interest capitalized to oil and natural gas development projects.

For the first nine months of 2011, corporate activities reflected net costs of $40.7 million compared to net costs of $133.5 million a year ago. Nine-month corporate costs in 2011 were significantly favorable to 2010 mostly related to the effects of transactions denominated in foreign currencies. Total after-tax benefits for foreign currency transactions were $32.2 million in the 2011 period compared to net after-tax costs of $58.8 million in the first nine months of 2010. Administrative expense was higher in 2011, primarily associated with increased employee compensation costs.

Discontinued Operations

On July 25, 2011, the Company announced that it had entered into an agreement to sell 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. The sale of the Superior refinery assets was completed on September 30, 2011. On September 1, 2011, the Company announced that it had entered into an agreement to sell its Meraux, Louisiana refinery and related assets for $325 million, plus the fair value of associated hydrocarbon inventories. The sale of the Meraux assets was completed on October 1, 2011. The Company began to account for the Superior, Wisconsin and Meraux, Louisiana refineries and associated marketing assets as discontinued operations beginning in the third quarter 2011. All prior periods presented have been reclassified to conform to this presentation of the Superior and Meraux operating results as discontinued operations.

Income from discontinued operations was $70.4 million in the third quarter 2011, including operating profits of $53.5 million and a net gain on sale of the two U.S. refineries of $16.9 million. The after-tax gain from disposal of the two refineries included a gain on the Superior refinery (including associated inventories) of $91.1 million and a loss on the Meraux refinery (including associated inventories) estimated at $74.2 million. The gain on disposal was based on refinery selling prices, plus the sales of all associated inventories at fair value, which was significantly above the last-in, first-out carrying value of the inventories sold. A loss on the sale of Meraux has been recorded in the third quarter 2011 because the Meraux business unit qualified for accounting purposes as an asset held for sale, which requires losses to be recorded when they can be estimated based on net realizable sales proceeds. Operating profits in 2011 of $53.5 million bested the 2010 profits of $5.4 million due to much stronger refining margins in the 2011 quarter.

Income from discontinued operations associated with the two U.S. refineries sold near the end of the third quarter 2011 was a profit of $132.4 million in the nine months of 2011 compared to a loss of $6.1 million in the 2010 period. The 2011 profit included a $16.9 million net gain on sale of the U.S. refineries, including associated marketing assets and inventories. The improvement in 2011 results was primarily due to significantly improved refining margins, higher crude oil throughputs at the refineries in the 2011 period, and the aforementioned gain on disposal.

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

Financial Condition

Net cash provided by operating activities was $1,876.7 million for the first nine months of 2011 compared to $2,200.9 million during the same period in 2010. Cash provided by operating activities of discontinued operations amounted to $163.5 million and $52.0 million, respectively, in the 2011 and 2010 periods. Changes in operating working capital other than cash and cash equivalents used cash of $309.4 million in the first nine months of 2011, but provided cash of $417.2 million in the first nine months of 2010. Cash was used for working capital in 2011 primarily due to an increase in accounts receivable caused by higher sales prices and cash paid for income taxes, which were only partially offset by an increase in accounts payable balances. Cash generated from working capital changes in the 2010 period included a $244.4 million recovery of U.S. federal royalties paid in prior years on oil and natural gas production in the Gulf of Mexico. Cash of $1,356.2 million in the 2011 period and $2,011.4 million in 2010 was generated from maturity of Canadian government securities that had maturity dates greater than 90 days at acquisition. The sale of gas storage assets in Spain in the 2011 nine-month period generated cash proceeds of $27.4 million. The sale of the Superior, Wisconsin refinery on September 30, 2011 provided cash proceeds of $403.8 million, including inventory sales. Cash associated with the sale of the Meraux, Louisiana refinery on October 1, 2011 was collected in the fourth quarter.

Significant uses of cash in both years were for dividends, which totaled $159.5 million in 2011 and $148.4 million in 2010, and for property additions and dry holes, which including amounts expensed, were $1,853.9 million and $1,532.5 million in the nine-month periods ended September 30, 2011 and 2010, respectively. Cash used for property additions related to discontinued operations totaled $48.1 million and $79.2 million, respectively in 2011 and 2010. Also, the purchase of Canadian government securities with maturity dates greater than 90 days at acquisition used cash of $1,233.3 million in the 2011 period and $1,862.6 million in the 2010 period. Total accrual basis capital expenditures were as follows:

	Nine Months Ended September 30,	
(Millions of dollars)	2011	2010
Capital Expenditures		
Exploration and production	$ 1,899.3	1,460.7
Refining and marketing, including discontinued operations	132.1	294.9
Corporate and other	4.4	4.5
Total capital expenditures, including discontinued operations	2,035.8	1,760.1

A reconciliation of property additions and dry hole costs in the consolidated statements of cash flows to total capital expenditures follows.

	Nine Months Ended September 30,	
(Millions of dollars)	2011	2010
Property additions and dry hole costs per cash flow statements, including discontinued operations	$ 1,902.0	1,611.7
Geophysical and other exploration expenses	95.4	69.7
Capital expenditure accrual changes, including discontinued operations	38.4	78.7
Total capital expenditures, including discontinued operations	2,035.8	1,760.1

Working capital (total current assets less total current liabilities) at September 30, 2011 was $996.8 million, an increase of $377.0 million from December 31, 2010. This level of working capital does not fully reflect the Company s liquidity position because the lower historical costs assigned to inventories under last-in first-out accounting were $824.5 million below fair value at September 30, 2011.

At September 30, 2011, long-term notes payable of $974.5 million had increased by $35.1 million compared to December 31, 2010. During 2011, the Company s $350 million notes maturing in May 2012 were reclassified to a current liability. In October 2011, the Company repaid $725 million of long-term debt outstanding at September 30, 2011, primarily with proceeds from sale of the Meraux, Louisiana and Superior, Wisconsin refineries. A summary of capital employed at September 30, 2011 and December 31, 2010 follows.

	Sept. 30, 2011		Dec. 31, 2010	
(Millions of dollars)	Amount	%	Amount	%
Capital employed				
Long-term debt	$ 974.5	9.9	939.4	10.3
Stockholders equity	8,888.4	90.1	8,199.5	89.7
Total capital employed	$ 9,862.9	100.0	9,138.9	100.0

The Company s ratio of earnings to fixed charges was 23.5 to 1 for the nine-month period ended September 30, 2011.

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

Accounting and Other Matters

In September 2011, the Financial Accounting Standards Board (FASB) issued an update that is intended to simplify the annual goodwill impairment assessment process by permitting a company to assess whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount before applying the two-step goodwill impairment test. If a company concludes that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the company would be required to conduct the current two-step goodwill impairment test. This change is effective for annual and interim goodwill impairment tests performed in fiscal years beginning after December 15, 2011, but early adoption is permitted. The Company is still evaluating the standard and may choose to early adopt this update for the annual goodwill impairment test due to be performed as of year-end 2011.

The Company adopted new guidance issued by the 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 amended previous guidance for determining whether an entity is considered a variable interest entity. The adoption of this guidance did not have a significant effect on the Company s consolidated financial statements.

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

The United States Congress passed the Dodd-Frank Act in 2010. Among other requirements, the law requires companies in the oil and gas industry to disclose payments made to the U.S. Federal and all foreign governments. The SEC was directed to develop the reporting requirements in accordance with the law. The SEC has issued preliminary guidance and has sought 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 Dodd-Frank Act.

Outlook

Average crude oil prices in October 2011 were somewhat lower than the average price during the third quarter of 2011. The Company expects its oil and natural gas production to range between 195,000 and 200,000 barrels of oil equivalent per day in the fourth quarter 2011. U.S. retail marketing margins have fallen in October versus the average margins achieved in the third quarter 2011. U.K. downstream margins remain extremely weak early in the fourth quarter 2011. The Company currently anticipates total capital expenditures for the full year 2011 to be approximately $3.0 billion.

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

Forward-Looking Statements

This Form 10-Q 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 Murphy s 2010 Annual Report on Form 10-K on file with the U.S. Securities and Exchange Commission. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

ITEM 3. 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 K to this Form 10-Q report, Murphy periodically makes 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 September 30, 2011 to hedge the purchase price of about 7.9 million bushels of corn and the sale price of about 1.6 million equivalent bushels of wet and dried distillers grain at the Company s ethanol production facilities. A 10% increase in the respective benchmark price of these commodities would have reduced the recorded asset associated with these derivative contracts by approximately $1.0 million, while a 10% decrease would have increased the recorded asset by a similar amount. Changes in the fair value of these derivative contracts generally offset the changes in the value for an equivalent volume of these feedstocks.

There were short-term derivative foreign exchange contracts in place at September 30, 2011 to hedge the value of the U.S. dollar against two foreign currencies. A 10% strengthening of the U.S. dollar against these foreign currencies would have increased the recorded net liability associated with these contracts by approximately $14.4 million, while a 10% weakening of the U.S. dollar would have decreased the recorded net liability by approximately $17.6 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.

There were short-term derivative interest rate contracts in place at September 30, 2011 to hedge fluctuations in cash flows of semi-annual interest payments attributable to changes in the benchmark interest rate. A 10% increase in the respective interest rate would have reduced the recorded liability associated with these derivative contracts by approximately $5.4 million, while a 10% decrease would have increased the recorded liability by a similar amount.

ITEM 4. CONTROLS AND PROCEDURES

Under the direction of its principal executive officer and principal financial officer, controls and procedures have been established by the Company 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 the Company s evaluation as of the end of the period covered by the filing of this Quarterly Report on Form 10-Q, 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) are 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.

There have been no changes in the Company s internal control over financial reporting during the quarter ended September 30, 2011 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

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PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Murphy is engaged in a number of 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.

ITEM 1A. RISK FACTORS

The Company s operations in the oil and gas business naturally lead to various risks and uncertainties. These risk factors are discussed in Item 1A. Risk Factors in our 2010 Form 10-K filed on February 28, 2011. The Company has not identified any additional risk factors not previously disclosed in its 2010 Form 10-K report.

ITEM 6. EXHIBITS

The Exhibit Index on page 37 of this Form 10-Q report lists the exhibits that are hereby filed, incorporated by reference, or furnished with this report.

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SIGNATURE

Pursuant to the requirements 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

(Registrant)

By /s/ JOHN W. ECKART
John W. Eckart, Vice President and

Controller *(Chief Accounting Officer*

and Duly Authorized Officer)

November 4, 2011

(Date)

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EXHIBIT INDEX

Exhibit No.	
2.1*	Asset Purchase Agreement between Calumet Specialty Products Partners, L.P. and Murphy Oil Corporation covering the Superior, Wisconsin refinery
2.2*	Asset Purchase Agreement between Valero Refining-Meraux LLC and Murphy Oil Corporation covering the Meraux, Louisiana refinery
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
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

* This exhibit is incorporated by reference within this Form 10-Q.

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.

Exhibits other than those listed above have been omitted since they are either not required or not applicable.