UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark one)

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

For the quarterly period ended September 30, 2003

OR

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

For the transition period from ______ to ______

Commission File Number 1-8590

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

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

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). ☒ Yes ☐ No

Number of shares of Common Stock, $1.00 par value, outstanding at September 30, 2003 was **91,855,935.**

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Murphy Oil Corporation and Consolidated Subsidiaries
CONSOLIDATED BALANCE SHEETS
(Thousands of dollars)

	(Unaudited) September 30, 2003	December 31, 2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 237,111	164,957
Accounts receivable, less allowance for doubtful accounts of $10,666 in 2003 and $9,307 in 2002	400,859	408,782
Inventories, at lower of cost or market		
Crude oil and blend stocks	125,957	41,961
Finished products	83,655	94,158
Materials and supplies	70,011	65,225
Prepaid expenses	41,765	59,962
Deferred income taxes	15,391	19,115
Total current assets	974,749	854,160
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $3,362,314 in 2003 and $3,361,726 in 2002	3,488,573	2,886,599
Goodwill, net	62,325	51,037
Deferred charges and other assets	91,757	93,979
Total assets	$ 4,617,404	3,885,775
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 62,474	57,104
Accounts payable and accrued liabilities	670,246	599,229
Income taxes	105,085	61,559
Total current liabilities	837,805	717,892
Notes payable	1,014,736	788,554
Nonrecourse debt of a subsidiary	43,434	74,254
Deferred income taxes	396,054	327,771
Asset retirement obligations	238,640	160,543
Accrued major repair costs	16,619	52,980
Deferred credits and other liabilities	172,866	170,228
Stockholders' equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued	—	—
Common Stock, par $1.00, authorized 200,000,000 shares, issued 94,613,379 shares	94,613	94,613
Capital in excess of par value	504,474	504,983
Retained earnings	1,317,622	1,137,177
Accumulated other comprehensive income (loss)	52,619	(66,790)
Treasury stock, 2,757,444 shares of Common Stock in 2003 and 2,923,925 shares in 2002, at cost	(72,078)	(76,430)
Total stockholders' equity	1,897,250	1,593,553
Total liabilities and stockholders' equity	$ 4,617,404	3,885,775

See Notes to Consolidated Financial Statements, page 5.

The Exhibit Index is on page 26.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF INCOME (unaudited)

(Thousands of dollars except per share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	**2002***	**2003**	**2002***
REVENUES				
Sales and other operating revenues	$ 1,284,913	1,044,279	3,833,309	2,827,628
Gain on sale of assets	10,353	3,500	59,651	9,200
Interest and other income	1,238	2,431	3,433	4,433
Total revenues	1,296,504	1,050,210	3,896,393	2,841,261
COSTS AND EXPENSES				
Crude oil and product purchases	884,693	748,328	2,629,125	1,915,163
Operating expenses	137,908	135,189	454,506	399,338
Exploration expenses, including undeveloped lease amortization	56,511	17,619	113,779	121,407
Selling and general expenses	31,862	23,166	91,615	68,657
Depreciation, depletion and amortization	83,994	66,581	237,725	219,744
Impairment of long-lived assets	3,488	9,154	3,488	9,154
Accretion on discounted liabilities	3,041	—	9,326	—
Interest expense	14,455	13,961	42,688	36,790
Interest capitalized	(10,027)	(7,172)	(29,675)	(16,596)
Total costs and expenses	1,205,925	1,006,826	3,552,577	2,753,657
Income from continuing operations before income taxes	90,579	43,384	343,816	87,604
Income tax expense	21,842	6,892	101,288	35,864
Income from continuing operations	68,737	36,492	242,528	51,740
Discontinued operations, net of tax	—	916	—	2,131
Income before cumulative effect of change in accounting principle	68,737	37,408	242,528	53,871
Cumulative effect of change in accounting principle, net of tax	—	—	(6,993)	—
NET INCOME	$ 68,737	37,408	235,535	53,871
INCOME (LOSS) PER COMMON SHARE – BASIC				
Income from continuing operations	$ .75	.40	2.64	.57
Discontinued operations	—	.01	—	.02
Cumulative effect of change in accounting principle	—	—	(.08)	—
NET INCOME – BASIC	$ .75	.41	2.56	.59
INCOME (LOSS) PER COMMON SHARE – DILUTED				
Income from continuing operations	$ .74	.40	2.62	.57
Discontinued operations	—	.01	—	.02
Cumulative effect of change in accounting principle	—	—	(.08)	—
NET INCOME – DILUTED	$ .74	.41	2.54	.59
Average common shares outstanding – basic	91,850,217	91,638,710	91,799,551	91,381,962
Average common shares outstanding – diluted	92,848,308	92,147,472	92,612,911	92,088,684

* Reclassified to conform to 2003 presentation.

See Notes to Consolidated Financial Statements, page 5.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (unaudited)

(Thousands of dollars)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	**2002**	**2003**	**2002**
Net income	$ 68,737	37,408	235,535	53,871
Other comprehensive income, net of tax				
Cash flow hedges				
Net derivative gains (losses)	(978)	(1,899)	(25,133)	5,723
Reclassification adjustments	10,872	(3,881)	38,010	(6,259)
Total cash flow hedges	9,894	(5,780)	12,877	(536)
Net gain (loss) from foreign currency translation	(35,864)	(35,538)	107,239	16,878
Minimum pension liability adjustment	—	—	(707)	—
COMPREHENSIVE INCOME (LOSS)	$ 42,767	(3,910)	354,944	70,213

See Notes to Consolidated Financial Statements, page 5.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Thousands of dollars)

	Nine Months Ended September 30, 2003	2002
OPERATING ACTIVITIES		
Income from continuing operations	$ 242,528	51,740
Adjustments to reconcile income from continuing operations to net cash provided by operating activities		
Depreciation, depletion and amortization	237,725	219,744
Provisions for major repairs	20,687	14,820
Expenditures for major repairs and asset retirements	(60,914)	(11,821)
Dry holes	61,966	78,373
Amortization of undeveloped leases	20,261	18,369
Impairment of long-lived assets	3,488	9,154
Accretion on discounted liabilities	9,326	—
Deferred and noncurrent income taxes	(3,652)	2,914
Pretax gains from disposition of assets	(59,651)	(9,200)
Net (increase) decrease in operating working capital other than cash and cash equivalents	66,108	(118,191)
Other	5,416	6,233
Net cash provided by continuing operations	543,288	262,135
Net cash provided by discontinued operations	—	5,554
Net cash provided by operating activities	543,288	267,689
INVESTING ACTIVITIES		
Property additions and dry holes	(705,202)	(614,631)
Proceeds from the sale of assets	77,899	55,383
Other – net	260	(77)
Investing activities of discontinued operations	—	(444)
Net cash required by investing activities	(627,043)	(559,769)
FINANCING ACTIVITIES		
Increase in notes payable	227,689	382,967
Decrease in nonrecourse debt of a subsidiary	(30,699)	(21,565)
Proceeds from exercise of stock options and employee stock purchase plans	2,879	23,488
Cash dividends paid	(55,090)	(52,563)
Other	(72)	(2,688)
Net cash provided by financing activities	144,707	329,639
Effect of exchange rate changes on cash and cash equivalents	11,202	6,165
Net increase in cash and cash equivalents	72,154	43,724
Cash and cash equivalents at January 1	164,957	82,652
Cash and cash equivalents at September 30	$ 237,111	126,376
SUPPLEMENTAL DISCLOSURES OF CASH FLOW ACTIVITIES		
Cash income taxes paid, net of refunds	$ 40,114	7,453
Interest paid, net of amounts capitalized	749	5,622

See Notes to Consolidated Financial Statements, page 5.

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 1 through 4 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, 2002. 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 and the results of operations and cash flows in conformity with accounting principles generally accepted in the United States.

Financial statements and notes to consolidated financial statements included in this Form 10-Q report should be read in conjunction with the Company's 2002 Form 10-K report, as certain notes and other pertinent information have been abbreviated or omitted in this report. Financial results for the nine months ended September 30, 2003 are not necessarily indicative of future results.

The financial information for the third quarter and first nine months of 2003, as furnished to the SEC on Form 8-K on October 29, 2003, is amended with the filing of this Form 10-Q to include subsequent exploration expense of $7.7 million ($4.4 million after tax).

Note B – New Accounting Principles

The Company adopted Emerging Issues Task Force (EITF) Topic 02-3 in the fourth quarter of 2002. Based on Topic 02-3, Murphy has reflected the results of its crude oil trading activities as net revenue in its income statement, and previously reported revenues and cost of sales in the nine-month period ended September 30, 2002 have been reduced by equal and offsetting amounts, with no changes to net income or cash flows. The effect of this reclassification was a net reduction of both net sales and cost of crude oil and product purchases by approximately $84 million and $237 million for the three-month and nine-month periods ended September 30, 2002.

On January 1, 2003, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations, which requires the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed in service. When the liability is initially recorded, the Company will increase the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Any difference between costs incurred upon settlement of an asset retirement obligation and the recorded liability will be recognized as a gain or loss in the Company's earnings. The asset retirement obligation is based on a number of assumptions requiring professional judgment. The Company cannot predict the type of revisions to these assumptions that will be required in future periods due to the availability of additional information, including prices for oil field services, technological changes, governmental requirements and other factors. Upon adoption of SFAS No. 143, the Company recorded a charge of $7 million, net of $1.4 million in income taxes, as the cumulative effect of a change in accounting principle. The noncash transition adjustment increased property, plant and equipment, accumulated depreciation, and asset retirement obligations by $142.9 million, $58.8 million, and $92.5 million, respectively.

The majority of the asset retirement obligation (ARO) recognized by the Company at September 30, 2003 relates to the estimated costs to dismantle and abandon its investment in producing oil and gas properties and related equipment. A portion of the transition adjustment and ARO relates to its investment in retail gasoline stations. The Company did not record a retirement obligation for certain of its refining and marketing assets because sufficient information is presently not available to estimate a range of potential settlement dates for the obligation. These assets are consistently being upgraded and are expected to be operational into the foreseeable future. The obligation for these refining and marketing assets will be initially recognized in the period in which sufficient information exists to estimate the timing and amount of the obligation.

Note B – New Accounting Principles *(Contd.)*

A reconciliation of the 2003 changes in the asset retirement obligations liability is shown in the following table.

(Thousands of dollars)	
December 31, 2002	$160,543
Transition adjustment	92,500
Accretion expense	9,326
Liabilities incurred	17,582
Liabilities settled	(58,536)
Changes due to translation of foreign currencies	17,225
September 30, 2003	$238,640

Liabilities settled includes approximately $54.9 million in noncash reductions of asset retirement obligations associated with the sale of certain oil and gas producing properties.

The pro forma asset retirement obligations as of January 1, 2002 and September 30, 2002 were $220 million and $236.4 million, respectively. Pro forma net income for the three-month and nine-month periods ended September 30, 2002, assuming SFAS No. 143 had been applied retroactively, is shown in the following table.

(Thousands of dollars except per share data)		**Three Months Ended September 30, 2002**	**Nine Months Ended September 30, 2002**
Net income	– As reported	$ 37,408	53,871
	Pro forma	37,966	55,846
Net income per share	– As reported, basic	$ .41	.59
	Pro forma, basic	.41	.61
	As reported, diluted	.41	.59
	Pro forma, diluted	.41	.61

On January 1, 2003, the Company adopted SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections, and SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities. SFAS No. 145 amends existing guidance on reporting gains and losses on the extinguishment of debt to prohibit the classification of the gain or loss as extraordinary and also amends SFAS No. 13 to require sale-leaseback accounting for certain lease modifications that have economic effects similar to sale-leaseback transactions. SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies EITF Issue 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity. The adoption of these two accounting standards did not have a material effect on the Company’s financial statements.

Additionally, beginning January 1, 2003, the Company has applied Financial Accounting Standards Board (FASB) Interpretation No. 45, Guarantor’s Accounting and Disclosure Requirement for Guarantees, Including Indirect Guarantees of Indebtedness to Others, an Interpretation of FASB Statements No. 5, 57 and 107 and a rescission of FASB Interpretation No. 34, and FASB Interpretation No. 46, Consolidation of Variable Interest Entities, an interpretation of ARB No. 51. Interpretation No. 45 elaborates on the disclosures to be made by a guarantor in its financial statements about its obligations under guarantees issued and requires under certain circumstances a guarantor to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken. Interpretation No. 46 addresses the consolidation by business enterprises of variable interest entities as defined in the Interpretation. The application of these two FASB Interpretations did not have a material effect on the Company’s financial statements.

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation – Transition and Disclosure, an amendment of FASB Statement No. 123. This Statement amends SFAS No. 123, Accounting for Stock-Based Compensation, to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. This Statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements, and these disclosures are included in the notes to these consolidated financial statements.

Note B – New Accounting Principles *(Contd.)*

In April 2003, the FASB issued SFAS 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. SFAS 149 amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities under SFAS 133, Accounting for Derivatives and Hedging Activities. SFAS 149 is effective for contracts entered into or modified after June 30, 2003, with all provisions applied prospectively. The Company's adoption of this statement did not have any impact on the Company's financial statements.

In May 2003, the FASB issued SFAS 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. This statement establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify an instrument that is within its scope as a liability. SFAS 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective July 1, 2003. The adoption of SFAS 150 had no impact on the Company's financial statements as the Company had no financial instruments with characteristics of both liabilities and equity.

Note C – Discontinued Operations

In December 2002, the Company sold its investment in Ship Shoal Block 113 in the Gulf of Mexico. Operations for the field in 2002 have been reported as Discontinued Operations in the Consolidated Statements of Income. Revenues and pretax earnings from the field were $4.3 million and $1.4 million, respectively, for the three-month period ended September 30, 2002 and $11.6 million and $3.3 million, respectively, for the first nine months of 2002.

Note D – Environmental Contingencies

In addition to being subject to numerous laws and regulations intended to protect the environment and/or impose remedial obligations, the Company is also involved in personal injury and property damage claims, allegedly caused by exposure to or by the release or disposal of materials manufactured or used in the Company's operations. The Company operates or has previously operated certain sites and facilities, including three refineries, 11 terminals, and approximately 80 service stations for which known or potential obligations for environmental remediation exist. In addition the Company operates or has operated numerous oil and gas fields that may require some form of remediation.

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. If regulatory authorities require more costly alternatives than the proposed processes, future expenditures could exceed the accrued liability by up to an estimated $3 million.

The Company has received notices from the U.S. Environmental Protection Agency (EPA) that it is currently considered a Potentially Responsible Party (PRP) at two Superfund sites. The potential total cost to all parties to perform necessary remedial work at these sites may be substantial. At one site the Company paid $6,500 to obtain release from further obligations. The Company's insurance carrier has agreed to reimburse the $6,500. Based on currently available information, the Company believes that it is a *de minimus* party as to ultimate responsibility at the other 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 one remaining site or other Superfund sites. The Company does not believe that the ultimate costs to clean-up the two Superfund sites will have a material adverse effect on its net income or cash flows 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 future net income or cash flows.

Note E – 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; 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 or 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.

In December 2000, two of the Company's Canadian subsidiaries, Murphy Oil Company Ltd. (MOCL) and Murphy Canada Exploration Company (MCEC) as plaintiffs filed an action in the Court of Queen's Bench of Alberta seeking a constructive trust over oil and gas leasehold rights to Crown lands in British Columbia. The suit alleges that the defendants, the Predator Corporation Ltd. and Predator Energies Partnership (collectively Predator) and Ricks Nova Scotia Co. (Ricks), acquired the lands after first inappropriately obtaining confidential and proprietary data belonging to the Company and its partner. In January 2001, Ricks, representing an undivided 75% interest in the lands in question, settled its portion of the litigation by conveying its interest to the Company and its partner at cost. In 2001, Predator, representing the remaining undivided 25% of the lands in question, filed a counterclaim, as subsequently amended, against MOCL and MCEC and MOCL's president individually seeking compensatory damages of C$4.61 billion. The Company believes that the counterclaim is without merit and that the amount of damages sought is frivolous. While the litigation is in the discovery stage and no assurance can be given about the outcome, the Company does not believe that the ultimate resolution of this suit will have a material adverse effect on its financial condition.

On June 10, 2003, a fire severely damaged the Residual Oil Supercritical Extraction (ROSE) unit at the Company's Meraux, Louisiana refinery. The ROSE unit recovers feedstock from the heavy fuel oil stream for conversion into gasoline and diesel. Subsequent to the fire, 16 class action lawsuits have been filed seeking damages for area residents. The Company maintains liability insurance that covers such matters, and it recorded the applicable insurance deductible as an expense in the second quarter of 2003. Accordingly, the Company does not believe that the ultimate resolution of the class action litigation will have a material adverse effect on its financial condition.

On March 5, 2002, two of the Company's subsidiaries filed suit against Enron Canada Corp. (Enron) to collect approximately $2.1 million owed to Murphy under canceled gas sales contracts. On May 1, 2002, Enron counterclaimed for approximately $19.8 million allegedly owed by Murphy under those same agreements. Although the lawsuit in the Court of Queen's Bench, Alberta, is in its early stages and no assurance can be given, the Company does not believe that the Enron counterclaim is meritorious and does not believe that the ultimate resolution of this matter will have a material adverse effect on its financial condition.

Murphy and its subsidiaries are engaged in a number of other legal proceedings, all of which Murphy considers routine and incidental to its business and none of which is expected to have a material adverse effect on the Company's financial condition. 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 earnings or financial condition 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, 2003, the Company had contingent liabilities of $8.1 million under a financial guarantee and $40.4 million on outstanding letters of credit. The Company has not accrued a liability in its balance sheet related to these letters of credit because it is believed that the likelihood of having these drawn is remote.

Note F – Earnings per Share and Stock Options

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, 2003 and 2002. 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)	**2003**	**2002**	**2003**	**2002**
Basic method	91,850,217	91,638,710	91,799,551	91,381,962
Dilutive stock options	998,091	508,762	813,360	706,722
Diluted method	92,848,308	92,147,472	92,612,911	92,088,684

There were no antidilutive options for the periods ended September 30, 2003 and 2002.

The Company accounts for its stock options using the intrinsic-value based method of accounting as prescribed by Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees,* and related interpretations. Under this method, compensation expense is not recorded for stock options since all option prices have been equal to or greater than the fair market value of the Company's stock on the date of grant. The Company would record compensation expense for any stock options deemed to be variable in nature. The Company has accrued compensation expense for prior performance-based restricted stock awards and adjusted such costs for changes in the fair market value of Common Stock. As of September 30, 2003, the Company had no outstanding restricted stock awards. SFAS No. 123, *Accounting for Stock-Based Compensation*, established accounting and disclosure requirements using a fair-value based method for stock-based employee compensation plans. As allowed by SFAS No. 123, the Company has elected to continue to apply the intrinsic-value based method prescribed by APB No. 25 and has adopted only the disclosure requirements of SFAS No. 123. Had the Company recorded compensation expense for stock options as prescribed by SFAS No. 123, net income and earnings per share for the three-month and nine-month periods ended September 30, 2003 and 2002, would be the pro forma amounts shown in the table below.

		Three Months Ended September 30,		Nine Months Ended September 30,	
(Thousands of dollars except per share data)		**2003**	**2002**	**2003**	**2002**
Net income	– As reported	$68,737	37,408	235,535	53,871
	Pro forma	67,349	35,964	231,716	49,857
Net income per share	– As reported, basic	$ .75	.41	2.56	.59
	Pro forma, basic	.73	.40	2.52	.55
	As reported, diluted	.74	.41	2.54	.59
	Pro forma, diluted	.72	.40	2.49	.55

Note G – Financial Instruments and Risk Management

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

- *Interest Rate Risks* – Murphy has variable-rate debt obligations that expose the Company to the effects of changes in interest rates. To partially reduce its exposure to interest rate risk, Murphy has interest rate swap agreements with notional amounts totaling $50 million at September 30, 2003 to hedge fluctuations in cash flows of a similar amount of variable rate debt. The swaps mature in 2004. Under the interest rate swaps, the Company pays fixed rates averaging 6.17% over their composite lives and receives variable rates which averaged 1.12% at September 30, 2003. The variable rate received by the Company under each contract is repriced quarterly. The Company has a risk management control system to monitor interest rate cash flow risk attributable to the Company's outstanding and forecasted debt obligations as well as the offsetting interest rate swaps. The control system involves using analytical techniques, including cash flow sensitivity analysis, to estimate the impact of interest rate changes on future cash flows. The fair value of the effective portions of the interest rate swaps and changes thereto is deferred in Accumulated Other Comprehensive Income (AOCI) and is subsequently reclassified into Interest Expense in the periods in which the hedged interest payments on the variable-rate debt affect earnings. For the periods ended September 30, 2003 and 2002, the income effect from cash flow hedging ineffectiveness of interest rates was insignificant. The fair value of the interest rate swaps are estimated using projected Federal funds rates, Canadian overnight funding rates and LIBOR forward curve rates obtained from published indices and counterparties. The estimated fair value approximates the values based on quotes from each of the counterparties.

- *Natural Gas Fuel Price Risks* – The Company purchases natural gas as fuel at its Meraux, Louisiana refinery, and as such, is subject to commodity price risk related to the purchase price of this gas. Murphy has hedged the cash flow risk associated with the cost of a portion of the natural gas it will purchase in 2004 through 2006 by entering into natural gas swap contracts with a total notional volume of 9.2 million British Thermal Units (MMBTU). Under the natural gas swaps, the Company pays a fixed rate averaging $2.78 per MMBTU and receives a floating rate in each month of settlement based on the average NYMEX price for the final three trading days of the month. Murphy has a risk management control system to monitor natural gas price risk attributable both to forecasted natural gas requirements and to Murphy's natural gas swaps. The control system involves using analytical techniques, including various correlations of natural gas purchase prices to future prices, to estimate the impact of changes in natural gas fuel prices on Murphy's cash flows. The fair value of the effective portions of the natural gas swaps and changes thereto is deferred in AOCI and is subsequently reclassified into Crude Oil and Product Purchases in the income statements in the periods in which the hedged natural gas fuel purchases affect earnings. For the periods ended September 30, 2003 and 2002, the income effect from cash flow hedging ineffectiveness for these contracts was insignificant.
- *Natural Gas Sales Price Risks* – The sales price of natural gas produced by the Company is subject to commodity price risk. Murphy has hedged the cash flow risk associated with the sales price for a portion of its natural gas production in the United States and Canada during 2003 by entering into financial contracts known as natural gas swaps and collars. The swaps cover a combined notional volume averaging 24,200 MMBTU equivalents per day and require Murphy to pay the average relevant index (NYMEX or AECO "C") price for each month and receive an average price of $3.76 per MMBTU equivalent. The natural gas collars are for a combined notional volume averaging 26,700 MMBTU equivalents per day and based upon the relevant index prices provide Murphy with an average floor price of $3.24 per MMBTU and an average ceiling price of $4.64 per MMBTU. Murphy has a risk management control system to monitor natural gas price risk attributable both to forecasted natural gas sales prices and to Murphy's hedging instruments. The control system involves using analytical techniques, including various correlations of natural gas sales prices to futures prices, to estimate the impact of changes in natural gas prices on Murphy's cash flows from the sale of natural gas.

The fair values of the effective portions of the natural gas swaps and collars and changes thereto are deferred in AOCI and are subsequently reclassified into Sales and Other Operating Revenues in the income statement in the periods in which the hedged natural gas sales affect earnings. For the three-month and nine-month periods ended September 30, 2003 and 2002, Murphy's earnings were not significantly affected by cash flow hedging ineffectiveness from these contracts.

During the nine-month period ended September 30, 2003, the Company paid approximately $12.8 million for settlement of natural gas swap and collar agreements in the U.S. and Canada, and during the same period in 2002, received approximately $7.9 million.

The fair value of the natural gas fuel swaps and the natural gas sales swaps and collars are both based on the average fixed price of the instruments and the published NYMEX and AECO "C" index futures price or natural gas price quotes from counterparties.

Note G – Financial Instruments and Risk Management ***(Contd.)***

- *Crude Oil Sales Price Risks* – The sales price of crude oil produced by the Company is subject to commodity price risk. Murphy has hedged the cash flow risk associated with the sales price for a portion of its crude oil production in the United States and Canada during 2003 by entering into financial contracts known as crude oil swaps. A portion of the swaps cover a notional volume of 22,000 barrels per day of light oil and require Murphy to pay the average of the closing settlement price on the NYMEX for the Nearby Light Crude Futures Contract for each month and receive an average price of $25.30 per barrel. Additionally, there are heavy oil swaps with a notional volume of 10,000 barrels per day (which equates to approximately 7,700 barrels per day of the Company's heavy oil production) that require Murphy to pay the arithmetic average of the posted price at the Kerrobert and Hardisty terminals in Canada for each month and receive an average price of $16.74 per barrel. Murphy has a risk management control system to monitor crude oil price risk attributable both to forecasted crude oil sales prices and to Murphy's hedging instruments. The control system involves using analytical techniques, including various correlations of crude oil sales prices to futures prices, to estimate the impact of changes in crude oil prices on Murphy's cash flows from the sale of light and heavy crude oil.

  The fair values of the effective portions of the crude oil hedges and changes thereto are deferred in AOCI and are subsequently reclassified into Sales and Other Operating Revenues in the income statement in the periods in which the hedged crude oil sales affect earnings. During 2003, cash flow hedging ineffectiveness relating to the crude oil sales swaps increased Murphy's after-tax earnings by $.6 million.

  During the nine-month period ended September 30, 2003 the Company paid approximately $51.3 million for settlement of maturing crude oil sales swaps.

  The fair value of the crude oil sales swaps are based on the average fixed price of the instruments and the published NYMEX index futures price or crude oil price quotes from counterparties.

- *Crude Oil Purchase Price Risks* – Each month, the Company purchases crude oil as the primary feedstock for its U.S. refineries. Prior to April 2000, the Company was a party to crude oil swap agreements that limited the exposure of its U.S. refineries to the risks of fluctuations in cash flows resulting from changes in the prices of certain crude oil purchases in 2002. Under each swap, Murphy would have paid a fixed crude oil price and would have received a floating price during the agreement's contractual maturity period. In April 2000, the Company settled certain of the swaps and entered into offsetting contracts for the remaining swap agreements, locking in a total pretax gain of $7.7 million. The fair values of these settlement gains were recorded in AOCI at January 1, 2001 associated with adoption of SFAS No. 133 as part of the transition adjustment and were recognized as a reduction of costs of crude oil purchases in the period the forecasted transactions occurred. Pretax gains of $5.2 million were reclassified from AOCI into earnings during the nine-month period ended September 30, 2002, including $1.6 million in the third quarter of 2002.

During the next twelve months, the Company expects to reclassify approximately $.3 million in net after-tax gains from AOCI into earnings as the forecasted transactions covered by hedging instruments actually occur. All forecasted transactions currently being hedged are expected to occur by December 2006.

Note H – Accumulated Other Comprehensive Income (Loss)

The components of Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheets at September 30, 2003 and December 31, 2002 are presented in the following table.

(Millions of dollars)	September 30, 2003	December 31, 2002
Foreign currency translation gain (loss), net	$ 50.3	(56.9)
Cash flow hedging, net	4.4	(8.5)
Minimum pension liability, net	(2.1)	(1.4)
Accumulated other comprehensive income (loss)	$ 52.6	(66.8)

The effect of SFAS Nos. 133/138, Accounting for Derivative Instruments and Hedging Activities, increased AOCI for the three months ended September 30, 2003 by $9.9 million, net of $6.8 million in income taxes, and hedging ineffectiveness decreased net income by $.8 million, net of $.4 million in income taxes. During 2003, hedging activities increased AOCI by $12.9 million, net of $8 million in income taxes, and hedging ineffectiveness increased income by $.6 million, net of $.4 million in income taxes. During 2003, losses of $38 million, net of $26.8 million in taxes, were reclassified from AOCI to earnings. During the three-month period ended September 30, 2002, AOCI decreased $5.8 million, net of $3.9 million in income taxes, and hedging ineffectiveness decreased net income by $.3 million, net of $.2 in income taxes. During the nine-month period ended September 30, 2002, hedging activities decreased AOCI by $.5 million, net of $.2 million in income taxes, and hedging ineffectiveness increased income by less than $.1 million. Gains of $6.3 million, net of $4.2 million in taxes, were reclassified from AOCI to earnings in the nine-month period ended September 30, 2002.

Note I – Business Segments

(Millions of dollars)	Total Assets at Sept. 30, 2003	Three Months Ended September 30, 2003			Three Months Ended September 30, 2002		
		External Revenues	Inter-segment Revenues	Income (Loss)	External Revenues	Inter-segment Revenues	Income (Loss)
Exploration and production*							
United States	$ 803.0	45.3	—	(.2)	49.3	.7	10.0
Canada	1,468.7	141.5	29.1	44.9	93.3	26.4	28.4
United Kingdom	196.7	27.5	—	10.0	38.8	—	11.2
Ecuador	110.9	9.5	—	3.7	11.5	—	5.4
Malaysia	275.4	40.7	—	10.9	—	—	1.1
Other	18.7	.5	—	(1.8)	.4	—	(1.2)
Total	2,873.4	265.0	29.1	67.5	193.3	27.1	54.9
Refining and marketing							
North America	1,178.4	910.7	—	3.8	756.5	—	(13.1)
United Kingdom	235.5	119.6	—	1.1	98.0	—	(.7)
Total	1,413.9	1,030.3	—	4.9	854.5	—	(13.8)
Total operating segments	4,287.3	1,295.3	29.1	72.4	1,047.8	27.1	41.1
Corporate and other	330.1	1.2	—	(3.7)	2.4	—	(4.7)
Total from continuing operations	$ 4,617.4	1,296.5	29.1	68.7	1,050.2	27.1	36.4

(Millions of dollars)	Nine Months Ended September 30, 2003			Nine Months Ended September 30, 2002		
	External Revenues	Inter-segment Revenues	Income (Loss)	External Revenues	Inter-segment Revenues	Income (Loss)
Exploration and production*						
United States	$ 145.9	—	15.4	117.6	1.6	2.1
Canada	456.5	54.4	143.3	361.0	61.0	100.2
United Kingdom	177.1	—	76.5	123.3	—	33.6
Ecuador	25.6	—	10.0	25.0	—	9.5
Malaysia	40.7	—	.1	—	—	(39.0)
Other	2.8	—	(3.2)	1.5	—	(2.4)
Total	848.6	54.4	242.1	628.4	62.6	104.0
Refining and marketing						
North America	2,686.4	—	(4.1)	1,929.8	—	(34.4)
United Kingdom	358.0	—	5.8	278.7	—	(1.1)
Total	3,044.4	—	1.7	2,208.5	—	(35.5)
Total operating segments	3,893.0	54.4	243.8	2,836.9	62.6	68.5
Corporate and other	3.4	—	(1.3)	4.4	—	(16.8)
Total from continuing operations	$3,896.4	54.4	242.5	2,841.3	62.6	51.7

* Additional details about results of oil and gas operations are presented in the tables on page 23.

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

Results of Operations

Third Quarter 2003 compared to Third Quarter 2002

Murphy's net income in the third quarter of 2003 totaled $68.7 million, $.74 per diluted share, compared to net income of $37.4 million, $.41 per diluted share, in the third quarter of 2002. The Company's income improvement in the 2003 third quarter was due to higher income contributions from both the exploration and production and refining and marketing businesses. In the current quarter, Murphy's exploration and production operations earned $67.5 million, an increase of $12.6 million from the $54.9 million earned in the 2002 quarter. The increase in income was primarily the result of higher oil sales volumes caused by record quarterly oil production and timing of sales, a higher average North American natural gas sales price, and a lower charge for impairment of Gulf of Mexico properties. These favorable variances were partially offset by lower natural gas sales volumes, lower average realized oil sales prices, higher exploration expenses and lower tax benefits. The Company's refining and marketing operations generated a profit of $4.9 million in the 2003 third quarter compared to a loss of $13.8 million for the same 2002 quarter. The improvement in 2003 was due to significantly better North American refining and marketing margins, and improved margins for the U.K. operations. The 2003 period included after-tax costs of $5.1 million relating to a fire at the Company's Meraux, Louisiana refinery on June 10, 2003.

Nine Months 2003 compared to Nine Months 2002

For the first nine months of 2003, net income totaled $235.5 million, $2.54 per diluted share, compared to $53.9 million, $.59 per diluted share, for the first nine months of 2002. The 2003 period included an after-tax cost of $7 million, $.08 per share, for the cumulative effect of a change in accounting principle attributable to adoption, as of January 1, 2003, of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. Earnings from the Company's exploration and production operations were $242.1 million, up $138.1 million in the first nine months of 2003 compared to the 2002 period. The improvement in 2003 was mainly due to a gain on the sale of certain North Sea properties, higher oil and natural gas sales prices, higher oil sales volumes caused by higher oil production, and lower exploration expenses. The Company had lower natural gas sales volumes in the 2003 period due to production declines at mature fields in western Canada and the Gulf of Mexico. The Company's refining and marketing operations earned $1.7 million in the first nine months of 2003 compared to a loss of $35.5 million in the 2002 period. North American refining and marketing margins were significantly stronger in the 2003 period compared to 2002. The 2003 period included net after-tax costs of $17.5 million related to the fire at the Meraux refinery on June 10, 2003. U.K. margins also improved in the 2003 period compared to the same period in 2002.

More detailed reviews of operating results for the Company's exploration and production and refining and marketing activities follows.

Exploration and Production

Results of continuing 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)	**2003**	**2002**	**2003**	**2002**
Exploration and production				
United States	$ (.2)	10.0	15.4	2.1
Canada	44.9	28.4	143.3	100.2
United Kingdom	10.0	11.2	76.5	33.6
Ecuador	3.7	5.4	10.0	9.5
Malaysia	10.9	1.1	.1	(39.0)
Other International	(1.8)	(1.2)	(3.2)	(2.4)
Total	$67.5	54.9	242.1	104.0

Exploration and production operations in the United States reported a net loss of $.2 million in the third quarter of 2003 compared to income of $10 million a year ago. The 2003 quarter had lower oil and natural gas sales volumes and higher dry hole costs. The 2002 period included a $14.7 million gain from settlement of tax matters, partially offset by after-tax costs of $3.2 million related to storm damages in the Gulf of Mexico.

Results of Operations (Contd.)

Exploration and Production (Contd.)

Operations in Canada earned $44.9 million this quarter compared to $28.4 million a year ago, due to a significant increase in offshore crude sales volumes due to timing of shipments and higher natural gas sales prices partially offset by a decline in natural gas sales volume and higher exploration expenses. Oil and gas liquids sales in Canada averaged 53,566 barrels a day, an increase of 67% from the prior year's third quarter, primarily because of higher offshore sales volumes due to timing of oil loadings. Canadian natural gas sales averaged 112 million cubic feet a day in the current quarter, down 42%, primarily due to lower production from the Ladyfern field.

U.K. operations earned $10 million in the current quarter, down from $11.2 million in the prior year. The decline in the current period is due to lower crude sales volumes following the sale of Ninian and Columba fields in the second quarter of this year, partially offset by lower dry holes expense.

Operations in Ecuador earned $3.7 million in the third quarter of 2003 compared to $5.4 million a year ago. The decline in Ecuador was primarily due to a 16% decrease in crude oil sales volumes, which were adversely affected by the timing of oil loadings for sale.

Malaysia reported income of $10.9 million in the just completed quarter compared to income of $1.1 million in the same period in 2002. The income in Malaysia in the current period was primarily attributable to first production at West Patricia in Block SK 309 in shallow-water Malaysia and an $11.4 million tax benefit to recognize certain deferred tax benefits related to prior year expenses, partially offset by increased exploration expense.

Operations in the United States for the nine months ended September 30, 2003 produced income of $15.4 million compared to income of $2.1 million in 2002. The improvement was primarily due to higher oil and natural gas sales prices, less workovers and major field repairs, and lower impairment charges in the latter period, partially offset by lower production of oil and natural gas due to field declines at Gulf of Mexico properties and a $14.7 million benefit from settlement of tax matters in the 2002 period that did not repeat.

In the first nine months of 2003, Canada operations earned $143.3 million compared to $100.2 million a year ago. Higher oil sales volumes and higher sales prices for oil and natural gas were partially offset by lower natural gas sales volumes.

Income in the U.K. for the nine-month period ended September 30, 2003 was $76.5 million compared to $33.6 million a year ago. The increase included the $34 million after-tax gain on sale of the Ninian and Columba fields in 2003, but was also up due to higher sales prices for crude oil, partially offset by lower sales volumes due to timing of liftings and the property sale.

For the first nine months of 2003, earnings in Ecuador were $10 million compared to $9.5 million for the 2002 period. Higher crude oil sales price in Ecuador in the 2003 period virtually offset the decline in oil sales volumes due to pipeline capacity restrictions.

Malaysia reported earnings of $.1 million in the first nine months of 2003 compared to a loss of $39 million a year ago. The improvement in Malaysia in 2003 was primarily due to start up of operations at West Patricia, the aforementioned $11.4 million deferred tax benefit, and $11.8 million lower exploration expense in the 2003 period.

On a worldwide basis, the Company's crude oil and condensate prices averaged $24.80 per barrel in the third quarter 2003 compared to $25.45 in the 2002 period. Average crude oil and liquids production was a Company-record 84,871 barrels per day, a 20% increase from 2002 as production began at the West Patricia field in shallow-water Block SK 309 Malaysia. Oil sales volumes averaged 87,734 barrels per day in the third quarter 2003, up 52% from 2002, primarily due to timing of oil sales off the east coast of Canada and first sales at the West Patricia field. North American natural gas sales prices averaged $4.60 per MCF in the third quarter compared to $2.80 per MCF in the same quarter of 2002. Total natural gas sales volumes averaged 203 million cubic feet a day in the third quarter 2003, down 30% from the 2002 quarter primarily due to lower production from the Ladyfern field in western Canada and mature fields in the Gulf of Mexico. The Company's 2003 hedging program, which expires at the end of 2003, reduced the average third quarter worldwide crude oil sales price and North American natural gas sales price by $1.78 per barrel and $.12 per MCF, respectively.

Results of Operations (Contd.)

Exploration and Production (Contd.)

For the first nine months of 2003, the Company's sales price for crude oil and condensate averaged $25.10 per barrel, a 10% increase from the 2002 period. Crude oil and condensate production increased 9% in the first nine months of 2003 and averaged 81,065 barrels per day. The increase was mostly attributable to first production from the West Patricia field in shallow-water Malaysia. Sales volumes for crude oil and condensate in the 2003 period were slightly lower than production due to the timing of sales for Malaysia and the U.K. Average sales prices for North American natural gas in the first nine months of 2003 were $4.96 per MCF, up 82% from 2002. Total natural gas sales volume declined by 29% and averaged 221 million cubic feet per day in the 2003 period, with the reduction caused by lower production at the Ladyfern field in western Canada and in the Gulf of Mexico.

The tables on page 23 provide additional details of the results of exploration and production operations for the third quarter and first nine months of each year.

Exploration and Production (Contd.)

Selected operating statistics for the three-month and nine-month periods ended September 30, 2003 and 2002 follow.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Net crude oil, condensate and gas liquids produced – barrels per day	84,871	70,569	81,065	74,290
Continuing operations	84,871	69,364	81,065	73,074
United States	4,011	3,806	3,774	4,434
Canada – light	2,268	3,032	2,894	3,399
– heavy	10,170	9,298	9,643	9,495
– offshore	26,700	20,725	28,408	22,271
– synthetic	12,009	12,922	10,604	11,036
United Kingdom	11,636	14,810	15,624	17,864
Ecuador	5,365	4,771	3,950	4,575
Malaysia	12,712	—	6,168	—
Discontinued operations	—	1,205	—	1,216
Net crude oil, condensate and gas liquids sold – barrels per day	87,734	57,717	80,128	73,663
Continuing operations	87,734	56,512	80,128	72,447
United States	4,011	3,806	3,774	4,434
Canada – light	2,268	3,032	2,894	3,399
– heavy	10,170	9,298	9,643	9,495
– offshore	29,119	6,875	28,948	20,887
– synthetic	12,009	12,922	10,604	11,036
United Kingdom	9,372	14,851	14,885	18,452
Ecuador	4,823	5,728	4,001	4,744
Malaysia	15,962	—	5,379	—
Discontinued operations	—	1,205	—	1,216
Net natural gas sold – thousands of cubic feet per day	203,162	288,439	220,703	311,151
Continuing operations	203,162	283,607	220,703	306,881
United States	85,071	86,072	82,220	92,862
Canada	111,861	192,591	130,000	207,718
United Kingdom	6,230	4,944	8,483	6,301
Discontinued operations	—	4,832	—	4,270
Total net hydrocarbons produced – equivalent barrels per day (1)	118,731	118,642	117,849	126,149
Total net hydrocarbons sold – equivalent barrels per day (1)	121,594	105,790	116,912	125,522
Weighted average sales prices				
Crude oil and condensate – dollars a barrel (2)				
United States (4)	$ 23.88	26.20	24.43	23.35
Canada (3) – light	24.92	25.24	27.09	21.88
– heavy (4)	13.08	19.92	12.66	16.91
– offshore (4)	27.08	27.00	26.70	24.45
– synthetic (4)	23.95	27.73	25.33	25.09
United Kingdom	28.80	27.52	29.43	23.57
Ecuador	21.40	21.65	23.42	19.35
Malaysia	27.66	—	27.66	—
Natural gas – dollars a thousand cubic feet				
United States (2) (4)	$ 4.94	3.34	5.48	3.13
Canada (3) (4)	4.34	2.56	4.63	2.53
United Kingdom (3)	2.28	1.81	3.11	2.62

(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) Three-month and nine-month 2003 prices include the effects of the Company's 2003 hedging program.

Results of Operations (Contd.)

Refining and Marketing

Results of refining and marketing operations are presented below by geographic segment.

(Millions of dollars)	Income (Loss) Three Months Ended September 30, 2003	2002	Nine Months Ended September 30, 2003	2002
Refining and marketing				
North America	$ 3.8	(13.1)	(4.1)	(34.4)
United Kingdom	1.1	(.7)	5.8	(1.1)
Total	$ 4.9	(13.8)	1.7	(35.5)

Refining and marketing operations in North America reported earnings of $3.8 million during the third quarter of 2003, including $5.1 million in after-tax costs relating to a fire at the Company's Meraux, Louisiana refinery, compared to a loss of $13.1 million in the same period a year ago. The Company's North American refining and marketing margins were significantly higher in the current quarter compared to margins in the same quarter of 2002. Earnings in the United Kingdom were $1.1 million in the third quarter of 2003 compared to losses of $.7 million in 2002. Worldwide petroleum product sales averaged a record 255,662 barrels a day in 2003, a 20% increase from the third quarter of 2002. Worldwide refinery inputs were 72,484 barrels a day in the third quarter of 2003 compared to 144,895 in the 2002 quarter. Inputs in the 2003 quarter were adversely affected by the Meraux refinery being out of service during the period due to a fire on June 10, 2003 and a planned refinery turnaround.

Refining and marketing operations in North America in the first nine months of 2003 reported a loss of $4.1 million, including the net after-tax costs of $17.5 million associated with the Meraux refinery fire, compared to a loss of $34.4 million in the 2002 period. The 2002 results include a net gain of $3.5 million from sale of the Company's interest in Butte Pipe Line. North American refining and marketing margins improved significantly in the current period compared to a year ago. Results in the United Kingdom reflected earnings of $5.8 million in the nine months ended September 30, 2003 compared to a loss of $1.1 million in 2002 due to higher margins compared to the same period a year ago.

Selected operating statistics for the three-month and nine-month periods ended September 30, 2003 and 2002 follow.

	Three Months Ended September 30, 2003	2002	Nine Months Ended September 30, 2003	2002
Refinery inputs – barrels per day	72,484	144,895	123,400	153,552
North America	39,356	111,913	88,738	117,712
United Kingdom	33,128	32,982	34,662	35,840
Petroleum products sold – barrels per day	255,662	212,757	252,754	206,339
North America	220,543	180,570	218,105	172,568
Gasoline	167,752	117,840	155,084	109,208
Kerosine	293	3,900	4,572	5,628
Diesel and home heating oils	34,070	32,279	38,825	35,679
Residuals	4,629	11,849	10,575	13,067
Asphalt, LPG and other	13,799	14,702	9,049	8,986
United Kingdom	35,119	32,187	34,649	33,771
Gasoline	14,112	10,076	11,879	11,919
Kerosine	1,725	2,656	2,383	2,583
Diesel and home heating oils	13,596	13,866	13,754	14,333
Residuals	3,748	2,594	3,785	2,939
LPG and other	1,938	2,995	2,848	1,997

Results of Operations (Contd.)

Corporate and other

The after-tax cost of corporate activities, which include interest income and expense and corporate overhead not allocated to operating functions, was $3.7 million in the current quarter, including $5.4 million in foreign currency gains, compared to $4.7 million in the 2002 quarter. In the 2003 period, lower income tax benefits and higher retirement plan costs were partially offset by foreign currency gains and lower net interest expense. In the first nine months of 2003, corporate activities reflected a net cost of $1.3 million compared to a net cost of $16.8 million a year ago. In addition to the aforementioned foreign currency gains, the nine-month 2003 results included a $20.1 million benefit from resolution of prior years' income tax matters. Excluding the income tax resolution benefit and foreign currency gains, higher costs in the first nine months of 2003 compared to the comparable 2002 period were primarily attributable to lower other income tax benefits.

In the third quarter of 2003, the Company determined that its wholly owned Canadian subsidiaries had improperly accounted for foreign currency transaction gains related to intercompany loans and third party debt denominated in U.S. dollars. The Company determined that the improper accounting had an immaterial effect on earnings in prior years and the 2003 and 2002 quarters. Therefore, the Company recorded after-tax income of $5.4 million in the third quarter of 2003 to reflect the proper accounting on a cumulative basis for the intercompany loans and third party debt.

Financial Condition

Net cash provided by continuing operations was $543.3 million for the first nine months of 2003 compared to $262.1 million for the same period in 2002. Changes in operating working capital other than cash and cash equivalents provided cash of $66.1 million in the first nine months of 2003 but used cash of $118.2 million in the first nine months of 2002. Proceeds from the sale of assets provided cash of $77.9 million in the first nine months of 2003 compared to $55.4 million in the same period in 2002. Cash from operating activities was reduced by expenditures for major repairs and asset retirements totaling $60.9 million in the current year and $11.8 million in 2002.

Other predominant uses of cash in each year were for dividends, which totaled $55.1 million in 2003 and $52.6 million in 2002, and for capital expenditures, which including amounts expensed, are summarized in the following table.

(Millions of dollars)	Nine Months Ended September 30, 2003	2002
Capital Expenditures		
Exploration and production	$582.3	463.7
Refining and marketing	153.6	175.0
Corporate and other	.8	.6
Total capital expenditures	736.7	639.3
Geological, geophysical and other exploration expenses charged to income	(31.5)	(24.6)
Total property additions and dry holes	$705.2	614.7

Working capital at September 30, 2003 was $136.9 million, virtually unchanged from December 31, 2002. This level of working capital does not fully reflect the Company's liquidity position, because the lower historical costs assigned to inventories under LIFO accounting were $120.2 million below current costs at September 30, 2003.

Financial Condition (Contd.)

At September 30, 2003, long-term notes payable of $1,014.7 million were up $226.1 million from December 31, 2002 due to funding of the Company's ongoing capital programs. Long-term nonrecourse debt of a subsidiary was $43.4 million, down $30.8 million from December 31, 2002, primarily due to repayments. A summary of capital employed at September 30, 2003 and December 31, 2002 follows.

	Sept. 30, 2003		Dec. 31, 2002	
(Millions of dollars)	Amount	%	Amount	%
Capital Employed				
Notes payable	$1,014.7	34	$ 788.6	32
Nonrecourse debt of a subsidiary	43.4	2	74.2	3
Stockholders' equity	1,897.3	64	1,593.6	65
Total capital employed	$2,955.4	100	$2,456.4	100

Accounting and Other Matters

As described in Note B on page 5 of this Form 10-Q report, Murphy adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, effective January 1, 2003.

The SEC has requested that the FASB review the accounting for mineral leases held by oil and gas companies. The SEC has stated that they believe producing and nonproducing mineral leases should be classified as intangible assets. Should the FASB agree with the SEC's view, the Company may be required to reclassify certain mineral lease assets, totaling about $157 million at September 30, 2003, from tangible assets now recorded in Property, Plant and Equipment to intangible assets in the Balance Sheet. These costs primarily relate to unamortized lease bonuses. Such a reclassification is not expected to have an impact on the Company's net income or cash flow.

Murphy holds a 20% interest in Block 16 Ecuador, where the Company and its partners produce oil for export. In 2001, the local tax authorities announced that Value Added Taxes (VAT) paid on goods and services related to Block 16 and many oil fields held by other companies will no longer be reimbursed. In response to this announcement, oil producers have filed actions in the Ecuador Tax Court seeking determination that the VAT in question is reimbursable. As of September 30, 2003, the Company has a receivable of approximately $8 million related to VAT. Murphy believes that its claim for reimbursement of VAT under applicable Ecuador tax law is valid, and it does not expect that the resolution of this matter will have a material adverse affect on the Company's financial position.

Outlook

The outlook for future oil, natural gas and refined product sales prices is uncertain. A number of factors could cause the prices for these products to weaken in future periods. Although the Organization of Petroleum Exporting Countries, known as OPEC, has recently agreed to reduce production by 900,000 barrels per day in an attempt to support oil prices, it is uncertain whether this move will keep oil at or near its current market price. The Company expects its production to average approximately 125,000 barrels of oil equivalent per day in the fourth quarter of 2003. A fire at the Meraux, Louisiana refinery on June 10, 2003 destroyed the Residual Oil Supercritical Extraction (ROSE) unit. The Company has estimated that it will take approximately one year to rebuild the ROSE unit. Without the ROSE unit, which recovers feedstock from the heavy fuel oil stream for conversion into gasoline and diesel, the refinery will have to process a more expensive, sweeter crude oil. The refinery has recently completed a scheduled plant-wide turnaround. During the turnaround, newly constructed equipment was tied in. With the new equipment, the plant will produce low-sulfur gasoline as required by new regulations beginning in 2004 and will also be capable of processing 125,000 barrels of crude oil per day.

Forward-Looking Statements

This Form 10-Q report contains statements of the Company's expectations, intentions, plans and beliefs that are forward-looking and are dependent on certain events, risks and uncertainties that may be outside of the Company's control. These forward-looking statements are made in reliance upon the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Actual results and developments could differ materially from those expressed or implied by such statements due to a number of factors including those described in the context of such forward-looking statements as well as those contained in the Company's January 15, 1997 Form 8-K report on file with the U.S. Securities and Exchange Commission.

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 G to this Form 10-Q report, Murphy makes use of derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions.

The Company was a party to interest rate swaps at September 30, 2003 with notional amounts totaling $50 million that were designed to hedge fluctuations in cash flows of a similar amount of variable-rate debt. These swaps mature in 2004. The swaps require the Company to pay an average interest rate of 6.17% over their composite lives, and at September 30, 2003, the interest rate to be received by the Company averaged 1.12%. The variable interest rate received by the Company under each swap contract is repriced quarterly. The Company considers these swaps to be a hedge against potentially higher future interest rates. The estimated fair value of these interest rate swaps was recorded as a liability of $2.4 million at September 30, 2003, with the offsetting loss recorded in Accumulated Other Comprehensive Income (AOCI) in Stockholders' Equity.

At September 30, 2003, 37% of the Company's debt had variable interest rates and 1.9% was denominated in Canadian dollars. Based on debt outstanding at September 30, 2003, a 10% increase in variable interest rates would increase the Company's interest expense approximately $1.1 million for the next 12 months after including the favorable effect resulting from lower net settlement payments under the aforementioned interest rate swaps. A 10% increase in the exchange rate of the Canadian dollar versus the U.S. dollar would increase interest expense for the next 12 months by less than $.1 million for debt denominated in Canadian dollars.

Murphy was a party to natural gas price swap agreements at September 30, 2003 for a total notional volume of 9.2 MMBTU that are intended to hedge the financial exposure of its Meraux, Louisiana refinery to fluctuations in the future price of a portion of natural gas to be purchased for fuel during 2004 through 2006. In each month of settlement, the swaps require Murphy to pay an average natural gas price of $2.78 per MMBTU and to receive the average NYMEX price for the final three trading days of the month. At September 30, 2003, the estimated fair value of these agreements was recorded as an asset of $18.3 million. A 10% increase in the average NYMEX price of natural gas would have increased this asset by $4.3 million, while a 10% decrease would have reduced the asset by a similar amount.

The Company was a party to natural gas swap agreements and natural gas collar agreements at September 30, 2003 that are intended to hedge the financial exposure of a portion of its 2003 U.S. and Canadian natural gas production to changes in gas sales prices. The swap agreements are for a combined notional volume that averages 24,200 MMBTU equivalents per day and require Murphy to pay the average relevant index price for each month and receive an average price of $3.76 per MMBTU equivalent. The collar agreements are for a combined notional volume of 26,700 MMBTU equivalents per day and based upon the relevant index prices provide Murphy with an average floor price of $3.24 per MMBTU and an average ceiling price of $4.64 per MMBTU. At September 30, 2003, the estimated fair value of these agreements was recorded as a liability of $1.1 million, with the offsetting loss recorded in AOCI in Stockholders' Equity. A 10% increase in the average index price of natural gas would have increased this liability by $1 million, while a 10% decrease would have reduced the liability by a similar amount.

In addition, the Company was a party to crude oil swap agreements at September 30, 2003 that are intended to hedge the financial exposure of a portion of its 2003 U.S. and Canadian crude oil production to changes in crude oil sales prices. A portion of the swap agreements cover a notional volume of 22,000 barrels per day of light oil and require Murphy to pay the average of the closing settlement price on the NYMEX for the Nearby Light Crude Futures Contract for each month and receive an average price of $25.30 per barrel. Additionally, there are heavy oil swap agreements with a notional volume of 10,000 barrels per day (which equates to approximately 7,700 barrels per day of the Company's heavy oil production) that require Murphy to pay the arithmetic average of the posted prices for each month at the Kerrobert and Hardisty terminals in Canada and receive an average price of $16.74 per barrel. At September 30, 2003, the estimated fair value of these agreements was recorded as a liability of $9.5 million, with the offsetting loss recorded in AOCI in Stockholders' Equity. A 10% increase in the average index prices of light oil and heavy oil would have increased this liability by $7.6 million, while a 10% decrease would have reduced the liability by a similar amount.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK (Contd.)

The Company is exposed to foreign currency exchange risk, primarily due to changes in the exchange rate for Canadian dollars and U.S. dollars. A portion of the Company's Canadian oil sales and financing activities are transacted in U.S. dollars. Therefore, the effects of changes in the exchange rate for Canadian dollars and U.S. dollars related to U.S. dollar denominated assets and liabilities of the Canadian operations are recorded in the Company's consolidated income. Based on September 30, 2003 U.S. dollar denominated assets and liabilities of the Canadian operations, a 10% increase in the exchange rate of the Canadian dollar versus the U.S. dollar would increase net income by $2.9 million, while a 10% decrease would reduce net income by a similar amount.

ITEM 4. CONTROLS AND PROCEDURES

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

Based on their evaluation during the quarter, 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 Rule 13a-15(e) under the Securities Exchange Act of 1934) are effective as of the end of the period covered by this report 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 were no significant changes in the Company's internal controls over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

CONTINUING OIL AND GAS OPERATING RESULTS (unaudited)

(Millions of dollars)	United States	Canada	United King-dom	Ecuador	Malaysia	Other	Synthetic Oil – Canada	Total
Three Months Ended September 30, 2003								
Oil and gas sales and other revenues	$ 45.3	143.9	27.5	9.5	40.7	.5	26.7	294.1
Production expenses	10.7	21.3	3.6	3.7	5.1	—	16.5	60.9
Depreciation, depletion and amortization	8.8	40.1	5.2	1.9	9.8	.1	2.4	68.3
Impairment of long-lived assets	3.0	—	—	—	—	—	—	3.0
Accretion on discounted liabilities	.8	1.3	.6	—	.1	.1	.1	3.0
Exploration expenses								
Dry holes	12.8	11.6	(.1)	—	13.3	—	—	37.6
Geological and geophysical	1.2	4.1	—	—	5.2	.4	—	10.9
Other	.6	.2	—	—	—	.1	—	.9
	14.6	15.9	(.1)	—	18.5	.5	—	49.4
Undeveloped lease amortization	3.1	3.9	.1	—	—	—	—	7.1
Total exploration expenses	17.7	19.8	—	—	18.5	.5	—	56.5
Selling and general expenses	4.6	7.3	.7	.2	.6	1.6	.1	15.1
Income tax provisions (benefits)	(.1)	17.4	7.4	—	(4.3)	—	(.6)	19.8
Results of operations (excluding corporate overhead and interest)	$ (.2)	36.7	10.0	3.7	10.9	(1.8)	8.2	67.5
Three Months Ended September 30, 2002								
Oil and gas sales and other revenues	$ 50.0	86.8	38.8	11.5	—	.4	32.9	220.4
Production expenses	10.1	18.5	6.7	4.2	—	—	12.1	51.6
Costs to repair storm damages	5.0	—	—	—	—	—	—	5.0
Depreciation, depletion and amortization	8.7	31.9	8.3	1.7	.2	.1	2.3	53.2
Impairment of long-lived assets	9.1	—	—	—	—	—	—	9.1
Exploration expenses								
Dry holes	3.3	.9	3.2	—	(1.8)	—	—	5.6
Geological and geophysical	1.7	1.4	—	—	.4	.3	—	3.8
Other	1.2	.6	.2	—	.1	—	—	2.1
	6.2	2.9	3.4	—	(1.3)	.3	—	11.5
Undeveloped lease amortization	2.7	3.4	—	—	—	—	—	6.1
Total exploration expenses	8.9	6.3	3.4	—	(1.3)	.3	—	17.6
Selling and general expenses	3.4	3.7	.8	.2	—	1.7	.1	9.9
Income tax provisions (benefits)	(5.2)	10.4	8.4	—	—	(.5)	6.0	19.1
Results of operations (excluding corporate overhead and interest)	$ 10.0	16.0	11.2	5.4	1.1	(1.2)	12.4	54.9
Nine Months Ended September 30, 2003								
Oil and gas sales and other revenues	$145.9	437.3	177.1	25.6	40.7	2.8	73.6	903.0
Production expenses	27.4	60.6	24.4	10.7	5.1	—	45.8	174.0
Depreciation, depletion and amortization	26.3	122.8	23.2	4.5	10.3	.2	6.7	194.0
Impairment of long-lived assets	3.0	—	—	—	—	—	—	3.0
Accretion on discounted liabilities	2.4	3.8	2.3	—	.2	.3	.3	9.3
Exploration expenses								
Dry holes	32.2	16.7	(.1)	—	13.3	(.1)	—	62.0
Geological and geophysical	7.0	6.0	—	—	12.7	.4	—	26.1
Other	2.9	1.4	.4	—	.5	.2	—	5.4
	42.1	24.1	.3	—	26.5	.5	—	93.5
Undeveloped lease amortization	8.5	11.7	.1	—	—	—	—	20.3
Total exploration expenses	50.6	35.8	.4	—	26.5	.5	—	113.8
Selling and general expenses	12.5	15.8	2.3	.4	2.8	4.8	.4	39.0
Income tax provisions (benefits)	8.3	72.0	48.0	—	(4.3)	.2	3.6	127.8
Results of operations (excluding corporate overhead and interest)	$ 15.4	126.5	76.5	10.0	.1	(3.2)	16.8	242.1
Nine Months Ended September 30, 2002								
Oil and gas sales and other revenues	$119.2	346.5	123.3	25.0	—	1.5	75.5	691.0
Production expenses	35.2	64.0	26.5	10.6	—	—	36.1	172.4
Costs to repair storm damages	5.0	—	—	—	—	—	—	5.0
Depreciation, depletion and amortization	26.3	116.7	26.2	4.3	.7	.2	6.5	180.9
Impairment of long-lived assets	9.1	—	—	—	—	—	—	9.1
Exploration expenses								

Dry holes	25.8	14.3	3.2	—	35.1	—	—	78.4
Geological and geophysical	5.0	10.5	—	—	1.0	.2	—	16.7
Other	3.4	1.6	.7	—	2.2	—	—	7.9
	34.2	26.4	3.9	—	38.3	.2	—	103.0
Undeveloped lease amortization	7.9	10.5	—	—	—	—	—	18.4
Total exploration expenses	42.1	36.9	3.9	—	38.3	.2	—	121.4
Selling and general expenses	9.5	10.6	2.4	.6	—	4.3	.2	27.6
Income tax provisions (benefits)	(10.1)	40.1	30.7	—	—	(.8)	10.7	70.6
Results of operations (excluding corporate overhead and interest)	$ 2.1	78.2	33.6	9.5	(39.0)	(2.4)	22.0	104.0

PART II – OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In December 2000, two of the Company's Canadian subsidiaries, Murphy Oil Company Ltd. (MOCL) and Murphy Canada Exploration Company (MCEC) as plaintiffs filed an action in the Court of Queen's Bench of Alberta seeking a constructive trust over oil and gas leasehold rights to Crown lands in British Columbia. The suit alleges that the defendants, the Predator Corporation Ltd. and Predator Energies Partnership (collectively Predator) and Ricks Nova Scotia Co. (Ricks), acquired the lands after first inappropriately obtaining confidential and proprietary data belonging to the Company and its partner. In January 2001, Ricks, representing an undivided 75% interest in the lands in question, settled its portion of the litigation by conveying its interest to the Company and its partner at cost. In 2001, Predator, representing the remaining undivided 25% of the lands in question, filed a counterclaim, as subsequently amended, against MOCL and MCEC and MOCL's president individually seeking compensatory damages of C$4.61 billion. The Company believes that the counterclaim is without merit and that the amount of damages sought is frivolous. While the litigation is in the discovery stage and no assurance can be given about the outcome, the Company does not believe that the ultimate resolution of this suit will have a material adverse effect on its financial condition.

On June 10, 2003, a fire severely damaged the Residual Oil Supercritical Extraction (ROSE) unit at the Company's Meraux, Louisiana refinery. The ROSE unit recovers feedstock from the heavy fuel oil stream for conversion into gasoline and diesel. Subsequent to the fire, 16 class action lawsuits have been filed seeking damages for area residents. The Company maintains liability insurance that covers such matters, and it recorded the applicable insurance deductible as an expense in the second quarter of 2003. Accordingly, the Company does not believe that the ultimate resolution of the class action litigation will have a material adverse effect on its financial condition.

On March 5, 2002, two of the Company's subsidiaries filed suit against Enron Canada Corp. (Enron) to collect approximately $2.1 million owed to Murphy under canceled gas sales contracts. On May 1, 2002, Enron counterclaimed for approximately $19.8 million allegedly owed by Murphy under those same agreements. Although the lawsuit in the Court of Queen's Bench, Alberta, is in its early stages and no assurance can be given, the Company does not believe that the Enron counterclaim is meritorious and does not believe that the ultimate resolution of this matter will have a material adverse effect on its financial condition.

Murphy and its subsidiaries are engaged in a number of other legal proceedings, all of which Murphy considers routine and incidental to its business and none of which is expected to have a material adverse effect on the Company's financial condition. Based on information currently available to the Company, the ultimate resolution of matters referred to in this Item is not expected to have a material adverse effect on the Company's earnings or financial condition in a future period.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) The Exhibit Index on page 26 of this Form 10-Q report lists the exhibits that are hereby filed or incorporated by reference.

(b) A report on Form 8-K was filed on July 14, 2003 that included the Company's News Release, announcing information regarding its expected results of operations for the quarter ended June 30, 2003.

(c) A report on Form 8-K was filed on July 30, 2003 that included the Company's News Release, announcing the Company's earnings and certain other financial information as of and for the three-month and first six-months periods that ended on June 30, 2003.

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, Controller
(Chief Accounting Officer and Duly Authorized Officer)

November 12, 2003
(Date)

EXHIBIT INDEX

Exhibit No.	
12.1*	Computation of Ratio of Earnings to Fixed Charges
31.1*	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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

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

Murphy Oil Corporation and Consolidated Subsidiaries

Computation of Ratio of Earnings to Fixed Charges (unaudited)

(Thousands of Dollars)

	Nine Months Ended Sept. 30, 2003	Year Ended December 31, 2002	2001	2000	1999	1998
Income (loss) from continuing operations before income taxes	$ 343,816	151,675	502,103	454,511	169,691	(12,774)
Distributions (less than) greater than equity in earnings of affiliates	(199)	(3)	(365)	(34)	64	(15)
Previously capitalized interest charged to earnings during period	7,612	7,748	3,450	3,507	3,146	2,172
Interest and expense on indebtedness, excluding capitalized interest	13,013	26,968	19,006	16,337	20,274	10,484
Interest portion of rentals (1)	8,055	9,445	7,953	5,808	3,267	3,293
Earnings before provision for taxes and fixed charges	**$ 372,297**	**195,833**	**532,147**	**480,129**	**196,442**	**3,160**
Interest and expense on indebtedness, excluding capitalized interest	13,013	26,968	19,006	16,337	20,274	10,484
Capitalized interest	29,675	24,536	20,283	13,599	7,865	7,606
Interest portion of rentals (1)	8,055	9,445	7,953	5,808	3,267	3,293
Total fixed charges	**$ 50,743**	**60,949**	**47,242**	**35,744**	**31,406**	**21,383**
Ratio of earnings to fixed charges	**7.3**	**3.2**	**11.3**	**13.4**	**6.3**	— (2)

(1) Calculated as one-third of rentals. Considered a reasonable approximation of interest factor.

(2) The computation of earnings was less than fixed charges by $18,223 in 1998.

EXHIBIT 31.1

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Claiborne P. Deming, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Murphy Oil Corporation;
2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;
3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:
    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;
    b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal controls over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: November 12, 2003

/s/ Claiborne P. Deming

Claiborne P. Deming
Principal Executive Officer

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Steven A. Cossé, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Murphy Oil Corporation;
2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;
3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:
    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;
    b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal controls over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: November 12, 2003

/s/ Steven A. Cossé

Steven A. Cossé
Principal Financial Officer

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Murphy Oil Corporation (the “Company”) on Form 10-Q for the period ended September 30, 2003 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), we, Claiborne P. Deming and Steven A. Cossé, Principal Executive Officer and Principal Financial Officer, respectively, of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to our knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

November 12, 2003

/s/ Claiborne P. Deming

Claiborne P. Deming
Principal Executive Officer

/s/ Steven A. Cossé

Steven A. Cossé
Principal Financial Officer