MURPHY OIL
2003

Murphy Oil Corporation Annual Report to Shareholders

MURPHY OIL AT A GLANCE

Murphy Oil Corporation ("Murphy" or the Company) is an international oil and gas company that conducts business through various operating subsidiaries. The Company produces oil and natural gas in the United States, Canada, the United Kingdom, Malaysia and Ecuador and conducts exploration activities worldwide. Murphy also has an interest in a Canadian synthetic oil operation, owns two petroleum refineries in the United States, and has an effective 30 percent interest in a refinery in the United Kingdom. The Company operates a growing gasoline station chain on Wal-Mart store parking lots in the United States, and also markets petroleum products under various brand names and to unbranded wholesale customers in the United States and the United Kingdom. Murphy is headquartered in El Dorado, Arkansas, has approximately 4,800 employees worldwide, and its common stock is traded on the New York Stock Exchange under the ticker symbol MUR.

Murphy Exploration & Production Company – USA is engaged in crude oil and natural gas exploration and production in the Gulf of Mexico and onshore Louisiana. The subsidiary conducts business from its offices in New Orleans, Louisiana.

Murphy Exploration & Production Company – International is engaged in crude oil and natural gas exploration and production in the U.K. sector of the North Sea, South America (Ecuador), Southeast Asia (Malaysia) and in West Africa (Congo-Brazzaville). The subsidiary is headquartered in Houston, Texas, and has offices in Kuala Lumpur, Malaysia, and London, England.

Murphy Oil Company Ltd. is engaged in conventional crude oil and natural gas exploration and production in Western Canada and offshore Eastern Canada, as well as the extraction and sale of synthetic crude oil from oil sands. The subsidiary also markets petroleum products to the Canadian market and is headquartered in Calgary, Alberta.

Murphy Oil USA, Inc. is engaged in refining, marketing and transportation of petroleum products in the United States. It is headquartered in El Dorado, Arkansas, at the Company's corporate office. Its two U.S. refineries in Meraux, Louisiana, and Superior, Wisconsin, provide petroleum products to high-volume, low-cost Murphy USA® branded gasoline stations located on-site at Wal-Mart Supercenters in 21 southern and midwestern states, and to wholesale branded Spur® stations in 23 states. Murphy Oil USA also operates a network of 12 Company-owned terminals. These terminals, along with a number of third-party terminals, supply fuel to retail and wholesale stations in 23 states.

Murphy Eastern Oil Company provides technical and professional services to certain Murphy Oil Corporation subsidiaries engaged in crude oil and natural gas exploration and production activities in the Eastern Hemisphere, and in refining and marketing of petroleum products in the United Kingdom primarily under the MURCO brand. The subsidiary is headquartered near London, England.

IN THIS REPORT

Front Cover Production commenced through this spar in November 2003 at the Company's Medusa field in Mississippi Canyon Block 538 in the deepwater Gulf of Mexico.

Underpinned by ongoing production from such core legacy assets as Terra Nova, Hibernia, Syncrude and Schiehallion, we can commit to focused exploration in high impact areas, specifically deepwater Gulf of Mexico and Malaysia.

– Claiborne P. Deming, President and Chief Executive Officer

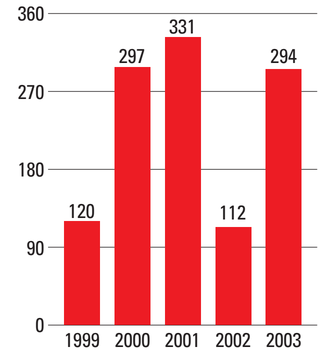
"Our capital expenditure program for 2003 included high impact development projects in the Gulf of Mexico and Malaysia, the Syncrude expansion program in Canada, and continued exploration with a four-well program to define the potential of our Malaysian deepwater blocks."

Dear Fellow Shareholders,

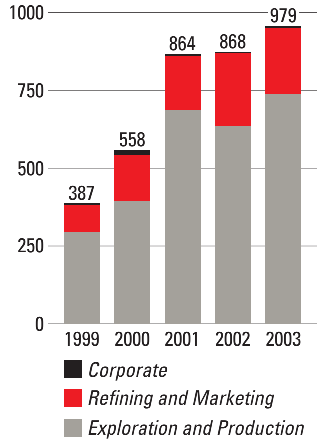
The saying goes "when one door closes, another opens." In regards to Murphy's performance throughout 2003 it is an apt description. As production declined from our legacy assets in Western Canada and the U.K. sector of the North Sea, new production ramped up in Malaysia and the Gulf of Mexico. And now, as we continue to develop our new discoveries, we are in position to refocus our energies as a blue chip international frontier exploration company that grows through the drill bit, a role that comes naturally to a company with wildcatter roots.

This year, although good to Murphy, has proven quite trying for the world in general. Uncertainty about world oil supply and the reaction of OPEC to the liberation of Iraq and a declining U.S. dollar value kept commodity prices artificially inflated. Despite such turbulence in our global landscape, we recorded encouraging results in terms of increased earnings and exploration successes with good long-term potential.

Net Income
Millions of dollars



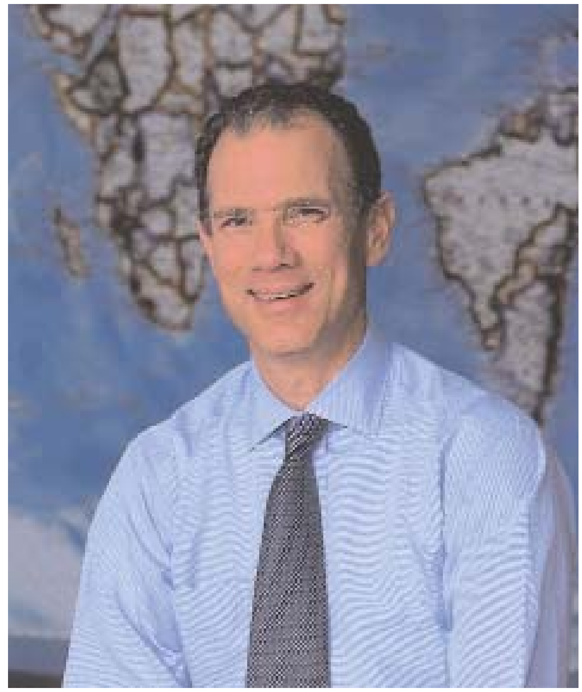
Capital Expenditures
Millions of dollars



Our Results By The Numbers

Our 2003 net income grew 164 percent to $294.2 million on revenues of $5.3 billion and our earnings per diluted share for the year were $3.17. The Company's income from exploration and production operations was $326.2 million, up 103 percent from 2002 levels. Although our refining and marketing operations had disappointing results, suffering an $11.2 million loss in 2003, the segment's financial results were a significant improvement over 2002.

Our worldwide crude oil and condensate sales prices averaged $25.27 per barrel during 2003, compared to $23.59 per barrel for 2002. Our total crude oil, condensate and gas liquids production was an average 83,452 barrels per day in 2003 compared to 76,370 barrels per day in 2002, with the net increase due primarily to production from our West Patricia field in Malaysia, and from Medusa and Habanero, our two Gulf of Mexico deepwater fields that came on stream late in the year. Our North American natural gas sales prices averaged $4.83 per thousand cubic feet during 2003, compared to $2.94 per thousand cubic feet during 2002. Natural gas sales volumes declined from 297 million cubic feet per day in 2002 to 215 million cubic feet per day in 2003, primarily due to lower production from our Ladyfern field in Western Canada.



Claiborne P. Deming
President and
Chief Executive Officer

Funding Our Growth

Our capital expenditure program for 2003 included high impact development projects in the Gulf of Mexico and Malaysia, the Syncrude expansion program in Canada, and continued exploration with a four-well program to define the potential of our Malaysian deepwater blocks. In addition to the $763 million of capital spending allocated to exploration and development worldwide, approximately $215 million was earmarked for downstream, including the completion of the Clean Fuels Project and a capacity upgrade at our Meraux, Louisiana, refinery, and the continued build-out of the Murphy USA program at Wal-Mart Supercenters. By year-end, 623 Murphy USA stations were in operation.

With the anticipated sharp decline of the once prolific Ladyfern field in Western Canada and the need for asset reallocation to fund ongoing frontier drilling and development programs throughout 2004, we announced plans to divest most of our conventional oil and gas properties in Western Canada. Continued growth in those maturing basins would have required substantial reinvestment at a time when our program outside North America is growing at a dynamic pace. Accordingly, we decided to capture and redeploy some of that value. This is consistent with our previous actions of disposing of high cost and less profitable mature properties, which included our interests in the Ship Shoal Block 113 field in the Gulf of Mexico Continental Shelf and the Ninian and Columba fields in the U.K. North Sea.

Building Our Bench Strength Inside and Out

To better reflect our capability as a frontier exploration and production company and a downstream refiner and marketer, we revised our organizational structure and added two key board members in early 2003. Our U.S. and international exploration and production operations were separated into two operating segments: Murphy Exploration & Production Company – USA, led by John Higgins, President; and Murphy Exploration & Production Company – International, led by David Wood, President. These two E&P subsidiaries, along with our Canadian subsidiary, Murphy Oil Company Ltd., with Harvey Doerr at the helm as President, now form the legs of a three-prong global E&P strategy that focuses on the Gulf of Mexico deepwater, Malaysia and West Africa (Congo), and Canada. Our worldwide downstream operations, consisting primarily of refining assets and retail marketing stations in the U.S. and U.K., are now headed by Mike Hulse, President. These are talented, intelligent and highly motivated executives who are responsible for our greatest successes in the past couple of years, and who are tasked with the future of our Company.

Added to our Board of Directors were: Frank Blue, a 28-year veteran of the oil industry with international experience in Southeast Asia and an esteemed attorney formerly with Fulbright & Jaworski in Houston, Texas; and Ivar Ramberg, Executive Officer of Ramberg Consulting AS of Lysaker, Norway, and formerly President and CEO of Norsk Hydro Canada.

The Lure of Frontier Exploration

Frontier exploration is in our blood. Underpinned by ongoing production from such core legacy assets as Terra Nova, Hibernia, Syncrude and Schiehallion, we can commit to focused exploration in high impact areas, specifically deepwater Gulf of Mexico and Malaysia. Our various drilling programs are further detailed in the discussion following this letter, but the potential in Malaysia deserves special note. We currently have interests in more than 14 million gross acres in three hydrocarbon provinces offshore Malaysia. Our Kikeh discovery in Block K will create value for Murphy for many years to come. Not only is our working interest 80 percent on Block K, but we are also operator. First production from Kikeh is projected for 2007.

Significant Downstream Momentum

Our downstream business is driven by our Wal-Mart program. In 2003, we opened 117 new Murphy USA stations and are planning for approximately 160 new builds for 2004. We have already earned more than one percent of the national market share in retail fuel sales, a significant achievement considering that this is only our fifth program year. Our success with Murphy USA has driven the expansion of our Meraux refinery's crude processing capacity to 125,000 barrels per day. We have also brought on line new processing equipment to manufacture "clean" fuels.

Living Up To Our Legacy

I sincerely believe that the reason we enjoyed such positive results for 2003 is because we earned it, and because we do not fit the mold of the typical independent exploration and production company.

First of all, our business model is two-fold with both upstream and downstream segments. Our growth through the drill bit is balanced by our retail assets. Second, we are calculated risk-takers who choose to participate in under-explored provinces with potential for sizable discoveries. Third, we are culturally and fiscally conservative and have a debt to total capitalization ratio that is one of the best in our industry. Fourth, we never forget that we are working for our shareholders and we continually strive to create value for them. We are wildcatters at heart, but we are well-prepared, accountable and hard-working.

It has been an eventful year for Murphy Oil Corporation and we are looking at 2004 and beyond from a positive perspective – with growing production, good exploratory prospects and an expanding retail market share. Although the future is always uncertain, we are confident that we have the fiscal strength, the operational tools and a deep pool of talent to meet whatever it brings our way.

Claiborne P. Deming

Claiborne P. Deming
President and Chief Executive Officer

February 17, 2004
El Dorado, Arkansas

FINANCIAL HIGHLIGHTS

(Thousands of dollars except per share data)	2003	2002	% Change 2003–2002	2001	% Change 2002–2001
For the Year					
Revenue	$ 5,345,238	$ 3,984,327	34%	$ 3,865,968	3%
Net income	294,197	111,508	164%	330,903	-66%
Cash dividends paid	73,464	70,898	4%	67,826	4%
Capital expenditures	979,164	868,100	13%	864,440	–
Net cash provided by operating activities	652,278	532,844	22%	635,704	-16%
Average common shares outstanding – diluted	92,742,766	92,134,967	.7%	91,181,998	1.0%
At End of Year					
Working capital	$ 228,529	$ 136,268	68%	$ 38,604	253%
Net property, plant and equipment	3,530,800	2,886,599	22%	2,525,807	14%
Total assets	4,712,647	3,885,775	21%	3,259,099	19%
Long-term debt	1,090,307	862,808	26%	520,785	66%
Stockholders' equity	1,950,883	1,593,553	22%	1,498,163	6%
Per Share of Common Stock					
Net income – diluted	$ 3.17	$ 1.21	162%	$ 3.63	-67%
Cash dividends paid	.80	.775	3%	.75	3%
Stockholders' equity	21.24	17.38	22%	16.53	5%

OPERATING HIGHLIGHTS

	2003	2002	% Change 2003–2002	2001	% Change 2002–2001
Net crude oil and gas liquids produced – barrels per day	83,452	76,370	9%	67,355	13%
United States	4,526	5,285	-14%	5,763	-8%
Canada	51,767	48,239	7%	36,059	34%
Other International	27,159	22,846	19%	25,533	-11%
Net natural gas sold – thousands of cubic feet per day	215,334	296,931	-27%	281,235	6%
United States	82,281	92,106	-11%	115,527	-20%
Canada	123,489	197,852	-38%	152,583	30%
United Kingdom	9,564	6,973	37%	13,125	-47%
Crude oil refined – barrels per day	119,281	143,829	-17%	167,199	-14%
North America	90,869	114,189	-20%	140,214	-19%
United Kingdom	28,412	29,640	-4%	26,985	10%
Petroleum products sold – barrels per day	264,928	210,631	26%	205,318	3%
North America	229,876	176,427	30%	174,256	1%
United Kingdom	35,052	34,204	2%	31,062	10%
Stockholder and Employee Data					
Common shares outstanding (thousands)[1]	91,871	91,689	.2%	90,662[2]	1.0%
Number of stockholders of record[1]	2,839	2,826	.5%	2,991	-5.5%
Number of employees[1]	4,789	4,010	19%	3,779	6%
Average number of employees	4,446	3,875	15%	3,438	13%

[1] At December 31.

[2] Adjusted for two-for-one stock split on December 30, 2002.

MAJOR EXPLORATION AND PRODUCTION PROPERTIES

MALAYSIA

Currently, Murphy has interests that vary between 60% and 85% in more than 14 million acres offshore Malaysia in Blocks SK 309 and 311, PM 311 and 312, and Sabah Blocks K, H, L and M. All are in known geologic provinces. New oil production from the West Patricia development in SK 309 came on stream in May 2003. Production from the Kikeh field is projected to come on stream in 2007.

GULF OF MEXICO

Murphy has interests in 173 blocks in the deepwater Gulf of Mexico and operates 116 of these blocks with working interests between 37.5% and 100%. To date, our activities in the deepwater Gulf of Mexico have yielded seven discoveries, including three major developments – Medusa, Habanero and Front Runner. The Company also has ownership interests in numerous blocks on the continental shelf of the Gulf of Mexico.

EASTERN CANADA

Operations in Eastern Canada include working interests in Canada's largest producing offshore assets, Hibernia and Terra Nova. The Company also holds exploration licenses on the Scotian Shelf near Sable Island.

WESTERN CANADA

We have a 5% interest in Syncrude, the world's largest synthetic crude oil operation. Going forward, after the completion of the announced sale of assets, Murphy's Western Canada conventional asset base will include heavy oil production in the Lloydminster and Seal areas and natural gas production in the Gilby area.

U.K. NORTH SEA

The Company counts Schiehallion, the U.K. North Sea's largest producing field, as a core asset that continues to provide important production for Murphy. Murphy also has significant production at the Mungo and Monan fields in the North Sea. In 2003, we sold our interests in the Ninian and Columba fields in the North Sea.

ECUADOR

With the completion of the OCP heavy crude pipeline, production increased in September 2003 on Ecuador Block 16 (20%), located in the Napo Basin on the east side of the Andes Mountains. The asset is producing approximately 52,000 barrels per day (8,000 net to Murphy) and has the potential to increase production to 75,000 barrels per day.

CONGO

Murphy holds an 85% interest in production sharing contracts covering two lightly explored deepwater blocks, Mer Profonde Nord and Mer Profonde Sud (MPN and MPS), totaling 1.8 million gross acres in the lower Congo basin located in a well-known and prolific geologic province.

Our deepwater Malaysian drilling program is focused on fully appraising the scope of our discoveries in the Sabah Trough.

EXPLORATION & PRODUCTION During 2003, we started up significant new production as our West Patricia field in Malaysia and our Medusa and Habanero fields in the Gulf of Mexico joined our major production assets, which include Terra Nova, Hibernia and Syncrude in Canada, and Schiehallion in the U.K. sector of the North Sea. For the full year, our worldwide production averaged 119,000 barrels of oil equivalent per day.

International – Focusing on Malaysia, Ecuador and Congo

In May 2003, our West Patricia development on Block SK 309 came on stream and ramped up to more than 15,000 barrels per day, 11,800 net to Murphy. We are especially pleased with our partnering agreement with PETRONAS-Carigali, and with the fast-tracked development of the West Patricia field, which took a mere 16 months from Field Development Plan approval to first oil. Our adjacent Congkak discovery will be produced through the West Patricia development and we are evaluating other prospects on our 85% held SK 309 and 311 blocks in hopes of bringing additional new production through the same infrastructure.

Our deepwater Malaysian drilling program is focused on fully appraising the scope of our discoveries on Block K (80%) in the Sabah Trough. Discovered in 2002, Kikeh is the largest oil discovery in Asia in many years. Kikeh Kecil, drilled in 2003 along the same trend, also showed similar pay sections as found in the Kikeh field. Late in the year, we flow-tested the Kikeh #4 well up to an equipment-limited maximum rate of 10,200 barrels per day from a single zone. We will continue to define the Kikeh complex and analogous acreage as we move towards development sanction in 2004 with first oil targeted for 2007. We believe there is much more exploratory work to do in the Sabah Trough. With our large ownership and acreage position in deepwater Malaysia, we plan to continue exploration of the province in 2004 drilling various prospects on Block K.

In 2002, we acquired 75% interests in two shallow water Peninsular Malaysia blocks (PM 311 and 312), totaling 3.2 million acres. Armed with newly acquired 3D seismic surveys over the northwestern corner of PM 311, we plan to drill two wildcats in the first half of 2004.

In September 2003, the lack of significant export capacity for our 20% owned Ecuador Block 16 producing asset was resolved with the completion of the new trans-Andean heavy crude pipeline (OCP). The field has ramped up to approximately 52,000 barrels per day, which results in 8,000 barrels per day net to Murphy and the fields in this acreage are capable of producing up to 75,000 barrels per day. Ecuador Block 16 provides a long-life producing asset for the Company's portfolio.

EXPLORATION AND PRODUCTION STATISTICAL SUMMARY

	2003	2002	2001	2000	1999
Net crude oil and condensate production – barrels per day					
United States	**4,374**	3,837	4,339	4,770	5,826
Canada – light	**1,419**	2,150	2,937	2,606	2,992
heavy	**9,962**	9,484	11,707	10,574	9,099
offshore	**28,534**	24,037	9,535	9,199	6,404
synthetic	**10,483**	11,362	10,479	8,443	10,997
United Kingdom	**14,513**	18,180	20,049	20,679	20,217
Ecuador	**5,172**	4,544	5,319	6,405	7,104
Malaysia	**7,301**	–	–	–	–
Net natural gas liquids production – barrels per day					
United States	**152**	291	413	551	777
Canada	**1,369**	1,206	1,401	474	488
United Kingdom	**173**	122	165	216	321
Continuing operations	**83,452**	75,213	66,344	63,917	64,225
Discontinued operations	–	1,157	1,011	1,342	1,858
Total liquids produced	**83,452**	76,370	67,355	65,259	66,083
Net crude oil and condensate sold – barrels per day					
United States	**4,374**	3,837	4,339	4,769	5,832
Canada – light	**1,419**	2,150	2,937	2,606	2,992
heavy	**9,962**	9,484	11,707	10,574	9,099
offshore	**28,542**	23,935	9,862	9,456	4,727
synthetic	**10,483**	11,362	10,479	8,443	10,997
United Kingdom	**14,591**	18,209	20,206	20,921	20,217
Ecuador	**4,997**	4,293	5,381	6,393	7,104
Malaysia	**7,235**	–	–	–	–
Net natural gas liquids sold – barrels per day					
United States	**152**	291	413	551	777
Canada	**1,369**	1,206	1,401	474	488
United Kingdom	**131**	149	148	216	321
Continuing operations	**83,255**	74,916	66,873	64,403	62,554
Discontinued operations	–	1,157	1,011	1,342	1,858
Total liquids sold	**83,255**	76,073	67,884	65,745	64,412
Net natural gas sold – thousands of cubic feet per day					
United States	**82,281**	88,067	112,616	141,373	163,587
Canada	**123,489**	197,852	152,583	73,773	56,238
United Kingdom	**9,564**	6,973	13,125	10,850	12,443
Continuing operations	**215,334**	292,892	278,324	225,996	232,268
Discontinued operations	–	4,039	2,911	3,416	8,175
Total natural gas sold	**215,334**	296,931	281,235	229,412	240,443
Net hydrocarbons produced – equivalent barrels[1,2] per day	**119,341**	125,859	114,228	103,494	106,157
Estimated net hydrocarbon reserves – million equivalent barrels[1,2,3]	**425.5**	455.3	501.2	442.3	400.8
Weighted average sales prices[4]					
Crude oil and condensate – dollars per barrel					
United States	**$ 24.22**	24.25	24.92	30.38	18.09
Canada[5] – light	**27.39**	22.60	22.40	27.68	17.00
heavy	**12.34**	16.82	11.06	17.83	12.77
offshore	**27.08**	25.36	23.77	27.16	19.08
synthetic	**24.97**	25.64	25.04	29.62	18.64
United Kingdom	**29.59**	24.39	24.44	27.78	18.09
Ecuador	**22.99**	19.64	17.00	22.01	14.42
Malaysia	**29.42**	–	–	–	–
Natural gas liquids – dollars per barrel					
United States	**23.42**	17.13	20.40	23.04	13.70
Canada[5]	**24.53**	16.35	20.35	19.98	12.09
United Kingdom	**22.49**	18.28	19.12	23.64	13.45
Natural gas – dollars per thousand cubic feet					
United States	**5.29**	3.37	4.64	4.01	2.34
Canada[5]	**4.52**	2.74	3.28	3.67	1.96
United Kingdom[5]	**3.50**	2.76	2.52	1.81	1.68

[1]Natural gas converted at a 6:1 ratio. [2]Includes synthetic oil. [3]At December 31. [4]Includes intracompany transfers at market prices. [5]U.S. dollar equivalent.

Kuala Lumpur, Malaysia, a thoroughly modern Asian city, is the location of our growing office from which we direct our offshore exploration and production operations in that country.

In 2003, we were able to negotiate contracts with favorable fiscal terms on two blocks of prospective acreage in the lower Congo basin – Mer Profonde Nord and Mer Profonde Sud (MPN and MPS). We believe this offshore area (85%) in Congo (Brazzaville) covering 1.8 million acres, has excellent potential as the region has yielded a number of significant discoveries in recent years. During the first four-year phase of our initial work period of 10 years, we have committed to drill three exploratory wells with the first well planned for 2004.

Canada – Heavy Oil and Frontier Focus

Over the past several years, our exploration strategy in Western Canada has been on the high risk side. However, with the decline of production from the Ladyfern field and the rapid increase in the industry's Western Canadian finding and development costs, we believe that it is time to refocus our Canadian portfolio back to heavy oil development in the Lloydminster and Seal areas, the Syncrude expansion scheduled for 2006 completion, and the frontier areas of the Scotian Shelf. In the last three years, we have routinely divested mature Western Canadian properties, and in December we announced our intention to sell the majority of our remaining conventional assets, with the intent to reallocate capital to our frontier exploration and development programs.

Efforts are currently underway to market these Western Canadian assets, with a proposed closing date prior to the end of the second quarter of 2004. In the meantime, Hibernia (6.5%), Terra Nova (12%) and Syncrude (5%) continue to provide significant cash flow for the Company. Both Hibernia and Terra Nova came on during a robust price environment and have proven to be outstanding investments. The Company will continue to seek future investments in Canada, with a focus in the medium term towards evaluation of heavy oil, oil sands and frontier exploration opportunities.

Developing in the Deepwater Gulf of Mexico

During 2003, our focus in the Gulf of Mexico has been on developing our Medusa, Habanero and Front Runner discoveries and lining up new drilling prospects. As these developments come on production, our primary focus will shift back to exploration on nearby acreage and in expanded areas of the Gulf of Mexico such as the newly opened Eastern Gulf and the lower Miocene subsalt play. Murphy currently owns rights (between 37.5% and 100%) in 173 deepwater lease tracts and operates 116.

We followed up our large Kikeh discovery in Malaysia in 2002 with further exploratory drilling success at Kikeh Kecil in 2003.

Medusa, located in 2,200 feet of water in Mississippi Canyon Blocks 538 and 582, commenced production in November 2003. The field produces through a spar facility designed to process up to 40,000 barrels of oil per day and 110 million cubic feet of natural gas per day. Murphy is the operator of the field (60%) and we anticipate peak net production to be approximately 25,000 barrels of oil equivalent per day by mid 2004 from six producing wells. Several identified prospects in the immediate area could also be tied back to the Medusa development, including Medusa North, which was successfully drilled in mid 2003. In addition, the Company controls 13 blocks in close proximity to the Medusa field with prospects that could easily be produced through the Medusa infrastructure.

The Habanero field, located in 2,013 feet of water in Garden Banks Block 341 (33.75%), came on stream in November 2003. It is a two well subsea tie-back to Shell's Auger tension leg platform, with expected peak production of 7,000 barrels of oil equivalent per day, net to Murphy. It is non-Murphy operated.

The Front Runner field, in water depth of 3,100 feet in Green Canyon Blocks 338 and 339, remains under development with installation of a spar facility (processing capacity of 60,000 barrels per day and 110 million cubic feet per day) scheduled for early 2004. Production is scheduled to begin in the second half of the year. Front Runner (37.5%) will produce from three discoveries, Front Runner (Green Canyon 338), Front Runner South (Green Canyon 339) and Quatrain (Green Canyon 382), and production rates are expected to peak at 20,000 barrels of oil equivalent per day, net to Murphy. Additional prospects around the Front Runner spar in the 13 blocks controlled by Murphy and its partners have also been earmarked for exploration.

With our current lease holdings, we are well positioned to explore the Gulf's emerging trends in 2004 and beyond. We own interests in 31 leases approved for drilling in the gas-prone Eastern Gulf. We will be carried in the drilling of our Dalmatian prospect (50%) in the DeSoto Canyon area in the second quarter of 2004 and we will drill the South Dachshund prospect (50%) in the Lloyd Ridge area in the second half of 2004. Our strategy going forward calls for a balanced drilling program that combines lower risk prospects that can be developed through existing infrastructure with higher risk, higher potential prospects in the more technologically challenging plays.

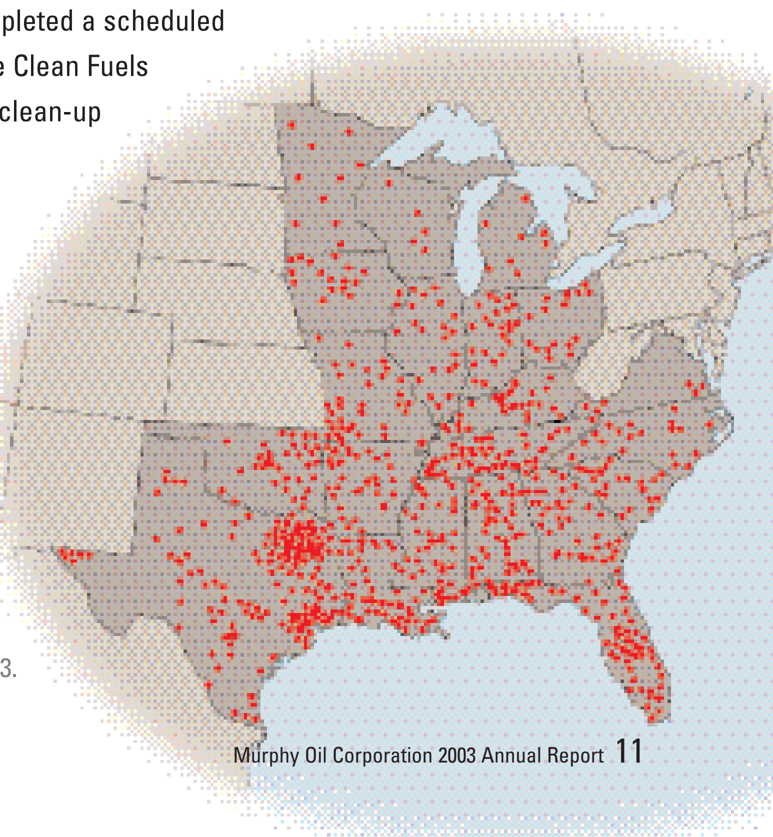
We believe that our retail program is second to none and that we can compete in any market environment while continuing to grow the system and increase sales volumes.

REFINING & MARKETING Throughout 2003, our downstream performance was mixed. For the year, our downstream operations lost $11.2 million on revenues of $4.2 billion. We continue to face margin pressures in 2004 with the sustained higher price of crude and with challenges encountered in our Meraux refinery operations due to a fire at mid-year 2003. Marketing results from our Murphy USA retail program located at Wal-Mart Supercenters continue to gain momentum as we have now opened more than 600 gas stations in 21 states. Our margins on the Murphy USA chain improved significantly in 2003 and both fuel and non-fuel sales volumes continue to grow.

Improving Refining Operations

Ongoing initiatives at the Meraux, Louisiana, refinery that include the expansion of its crude processing capacity from 100,000 to 125,000 barrels per day and the Clean Fuels Project, were temporarily derailed in early June 2003. A fire in the Residual Oil Supercritical Extractor (ROSE) unit, although confined to a small area, caused severe damage and the ROSE unit was a total loss. Subsequently, the entire plant remained off-line through the third quarter of the year as a result of fire damage. During this downtime, we completed a scheduled plant turnaround and the crude capacity expansion, tied-in the Clean Fuels Project equipment as originally planned, and commenced the clean-up and rebuild of the ROSE unit, anticipated to be completed by October 2004. Murphy's downstream capital expenditures will decrease dramatically in 2004 as a result of the completion of the plant's expansion.

The Meraux refinery came back on line in the fourth quarter with the capability to manufacture 100% ultra-low sulfur fuels, making Meraux one of the first refineries in the country to produce both gasoline and diesel fuels that meet the new low-sulfur standards.



The Company had 623 Murphy USA gasoline stations at Wal-Mart stores as of December 31, 2003.

REFINING & MARKETING STATISTICAL SUMMARY

	2003	2002	2001	2000	1999
Refining					
Crude capacity* of refineries – barrels per stream day	**192,400**	167,400	167,400	167,400	167,400
Refinery inputs – barrels per day					
Crude – Meraux, Louisiana	**60,403**	83,721	104,345	103,154	82,410
Superior, Wisconsin	**30,466**	30,468	35,869	34,159	33,402
Milford Haven, Wales	**28,412**	29,640	26,985	28,507	27 ,392
Other feedstocks	**10,113**	11,013	9,901	8,298	10,484
Total inputs	**129,394**	154,842	177,100	174,118	153,688
Refinery yields – barrels per day					
Gasoline	**52,162**	63,409	73,217	75,106	65,216
Kerosine	**6,568**	9,446	12,874	11,955	11,316
Diesel and home heating oils	**41,277**	48,344	52,660	49,606	44,054
Residuals	**14,595**	16,589	20,530	18,524	17,370
Asphalt, LPG and other	**11,986**	12,651	13,467	14,624	12,225
Fuel and loss	**2,806**	4,403	4,352	4,303	3,507
Total yields	**129,394**	154,842	177,100	174,118	153,688
Average cost of crude inputs to refineries – dollars per barrel					
North America	**$ 29.79**	24.76	23.44	28.82	18.80
United Kingdom	**30.24**	25.83	24.86	29.29	17 .22
Marketing					
Products sold – barrels per day					
North America – Gasoline	**162,911**	112,281	96,597	76,314	61,786
Kerosine	**4,388**	5,818	9,621	8,517	7,545
Diesel and home heating oils	**43,373**	35,995	41,064	39,347	34,514
Residuals	**10,972**	13,759	17,308	15,163	13,812
Asphalt, LPG and other	**8,232**	8,574	9,666	10,271	9,134
	229,876	176,427	174,256	149,612	126,791
United Kingdom – Gasoline	**12,101**	12,058	11,058	11,622	12,511
Kerosine	**2,526**	2,685	2,547	2,478	3,053
Diesel and home heating oils	**13,506**	14,574	11,798	9,760	10,995
Residuals	**3,816**	3,127	3,538	3,852	3,608
LPG and other	**3,103**	1,760	2,121	2,191	2,084
	35,052	34,204	31,062	29,903	32,251
Total products sold	**264,928**	210,631	205,318	179,515	159,042
Branded retail outlets*					
North America	**994**	914	815	712	625
United Kingdom	**384**	416	411	386	384

*At December 31.

Our gasoline fueling stations at Wal-Mart stores in 21 states continued to grow in 2003 as we added 117 stores in the United States and experienced 9% fuel sales volume growth at stores open one year or more.

In other refining operations, our Superior refinery in Wisconsin set a new record for asphalt sales with 1.8 million barrels produced and sold during 2003. Asphalt makes a significant contribution to our bottom line and the increase in asphalt production means an increase in the volumes of Canadian heavy sour crude that we purchase, which in turn, lowers our feedstock costs for Superior. Our Meraux, Superior and Milford Haven (Wales) refineries process and supply fuels for the Company's retail operations – the 623 Murphy USA gasoline stations situated at Wal-Mart stores in 21 states and 104 operated MURCO fuel outlets in the U.K.

Surging Retail Operations

Thanks in large part to our association with Wal-Mart in 21 states, we have become a national leader in the retail marketing arena. During the year, we more than met our goal of building and opening 100 new locations. By the end of 2003, we had opened 117 new Murphy USA outlets and increased our market share in sales volume to more than 1% nationwide. Monthly fuel sales volumes showed significant increases throughout the year, with same-store fuel volumes (open one or more years) averaging 9% higher in 2003 than in 2002. Non-fuel sales jumped by more than 50% over the prior year's levels due, in part, to outstanding efforts by our retail associates in the field and innovative marketing strategies.

Our retail network is one of the largest new players in the fuel marketing arena. Murphy USA stations are high volume outlets with low capital costs and equally low per-unit operating costs, all of which enable us to compete in a low margin environment.

As ambitious as our expansion plans were for 2003, our plans for 2004 are even more aggressive with 160 new units planned throughout the southern and midwestern United States. We believe that our retail program is second to none and that we can compete in any market environment while continuing to grow the system and increase sales volumes.

LEADERSHIP

BOARD OF DIRECTORS

William C. Nolan, Jr.
Partner, Nolan and Alderson, El Dorado, Arkansas. Director since 1977.
Chairman of the Board and the Executive Committee

Claiborne P. Deming
President and Chief Executive Officer, Murphy Oil Corporation, El Dorado, Arkansas.
Director since 1993.
Committees: Executive

Frank W. Blue
Attorney, Santa Barbara, California.
Director since 2003.
Committees: Audit; Nominating and Governance

George S. Dembroski
Vice Chairman, Retired, RBC Dominion Securities Limited, Toronto, Ontario, Canada.
Director since 1995.
Committees: Executive; Audit; Executive Compensation (Chairman)

H. Rodes Hart
Chairman and Chief Executive Officer, Franklin Industries, Inc., Nashville, Tennessee.
Director since 1975.
Committees: Audit; Executive Compensation

Robert A. Hermes
Chairman of the Board, Purvin & Gertz, Inc., Houston, Texas.
Director since 1999.
Committees: Nominating and Governance (Chairman); Public Policy and Environmental

R. Madison Murphy
Private Investor, El Dorado, Arkansas.
Director since 1993; Chairman from 1994-2002
Committees: Executive; Audit (Chairman)

Ivar B. Ramberg
Executive Officer, Ramberg Consulting AS (Ram-Co), Lysaker, Norway.
Director since 2003.
Committees: Nominating and Governance; Public Policy and Environmental

David J. H. Smith
Chief Executive Officer, Retired, Whatman plc, Maidstone, Kent, England.
Director since 2001.
Committees: Executive Compensation; Public Policy and Environmental

Caroline G. Theus
President, Keller Enterprises, LLC, Alexandria, Louisiana.
Director since 1985.
Committees: Executive Committee; Public Policy and Environmental (Chairman)

Director Emeritus
William C. Nolan

EXECUTIVE OFFICERS

Claiborne P. Deming
President and Chief Executive Officer since October 1994 and Director and Member of the Executive Committee since 1993. Mr. Deming served as Executive Vice President and Chief Operating Officer from 1992 to 1993 and President of Murphy Oil USA, Inc. from 1989 to 1992.

Steven A. Cossé
Senior Vice President since October 1994 and General Counsel since August 1991. Mr. Cossé was elected Vice President in 1993. For the eight years prior to August 1991, he was General Counsel for Ocean Drilling & Exploration Company (ODECO), a majority-owned subsidiary of Murphy.

W. Michael Hulse
Executive Vice President – Worldwide Downstream Operations effective April 2003. Mr. Hulse was President of MOUSA from November 2001 to present. He served as President of Murphy Eastern Oil Company from April 1996 to November 2001.

Bill H. Stobaugh
Vice President since May 1995 when he joined the Company. Prior to that, he held various engineering, planning and managerial positions, the most recent being with an engineering consulting firm.

Kevin G. Fitzgerald
Treasurer since July 2001. Mr. Fitzgerald was Director of Investor Relations from 1996 to June 2001 and also served in various capacities with the Company and ODECO between 1982 and 1996.

John W. Eckart
Controller since March 2000. Mr. Eckart was Assistant Controller from February 1995 to March 2000, after joining the Company as Auditing Manager in 1990.

Walter K. Compton
Secretary since December 1996. Mr. Compton became Manager, Law Department, in November 1996, and has been an attorney with the Company since 1988.

PRINCIPAL SUBSIDIARIES

Murphy Exploration & Production Company – USA Engages in crude oil and natural gas exploration and production in the Gulf of Mexico and the continental U.S.	131 South Robertson Street New Orleans, Louisiana 70112 (504) 561-2811 Mailing Address: P.O. Box 61780 New Orleans, Louisiana 70161-1780	**John C. Higgins** President **S.J. Carboni, Jr.** Vice President, Deepwater Development and Production **James R. Murphy** Vice President, Exploration **Steven A. Cossé** Vice President and General Counsel	**Kevin G. Fitzgerald** Treasurer **Gasper F. Bivalacqua** Controller **Walter K. Compton** Secretary
Murphy Oil Company Ltd. Engages in crude oil and natural gas exploration and production, extraction and sale of synthetic crude oil, and marketing of petroleum products in Canada.	2100-555-4th Avenue SW Calgary, Alberta T2P 3E7 (403) 294-8000 Mailing Address: P.O. Box 2721, Station M Calgary, Alberta T2P 3Y3 Canada	**Harvey Doerr** President **Steve C. Crosby** Vice President, East Coast and Northern Canada **Timothy A. Larson** Vice President, Crude Oil and Natural Gas	**J. Terry McCoy** Vice President, Exploration and Land **W. Patrick Olson** Vice President, Production **Robert L. Lindsey** Vice President, Finance and Secretary **Kevin G. Fitzgerald** Treasurer
Murphy Exploration & Production Company – International Engages in crude oil and natural gas exploration and production outside North America and in Alaska.	550 WestLake Park Blvd. Suite 1000 Houston, Texas 77079 (281) 249-1040	**David M. Wood** President **George M. Shirley** Vice President and General Manager – Malaysia **Steven A. Cossé** Vice President and General Counsel	**Kevin G. Fitzgerald** Treasurer **Dean E. Haefner** Controller **Walter K. Compton** Secretary
Murphy Oil USA, Inc. Engages in refining and marketing of petroleum products in the United States.	200 Peach Street El Dorado, Arkansas 71730 (870) 862-6411 Mailing Address: P.O. Box 7000 El Dorado, Arkansas 71731-7000	**W. Michael Hulse** President **Charles A. Ganus** Senior Vice President, Marketing **Gary R. Bates** Vice President, Supply and Transportation **Ernest C. Cagle** Vice President, Manufacturing **Henry J. Heithaus** Vice President, Retail Marketing	**Steven A. Cossé** Vice President and General Counsel **Gordon W. Williamson** Treasurer **John W. Eckart** Controller **Walter K. Compton** Secretary
Murphy Eastern Oil Company Provides technical and professional services to certain of Murphy Oil Corporation's subsidiaries engaged in crude oil and natural gas exploration and production in the Eastern Hemisphere and refining and marketing of petroleum products in the U.K.	4 Beaconsfield Road St. Albans, Hertfordshire AL1 3RH, England 172-789-2400	**Stephen R. Wylie** President **Kevin W. Melnyk** Vice President, Supply and Refining **Ijaz Iqbal** Vice President	**Kevin G. Fitzgerald** Treasurer **Walter K. Compton** Secretary

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

FORM 10-K

(Mark One)

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

For the fiscal year ended **December 31, 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	**71-0361522**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
200 Peach Street, P.O. Box 7000, El Dorado, Arkansas	**71731-7000**
(Address of principal executive offices)	(Zip Code)

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

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

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

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

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, and (2) has been subject to such filing requirements for the past 90 days. Yes_√_ No___.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [√]

Aggregate market value of the voting stock held by non-affiliates of the registrant, based on average price at January 31, 2004, as quoted by the New York Stock Exchange, was approximately $4,235,014,000.

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes_√_ No___.

Aggregate market value of the voting stock held by non-affiliates of the registrant, based on average price at June 30, 2003, as quoted by the New York Stock Exchange, was approximately $3,683,817,000.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2004 was 91,880,304.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 12, 2004 have been incorporated by reference in Part III herein.

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MURPHY OIL CORPORATION

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PART I

Items 1. and 2. BUSINESS AND PROPERTIES

Summary

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

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

The information appearing in the 2003 Annual Report to Security Holders (2003 Annual Report) is incorporated in this Form 10-K report as Exhibit 13 and is deemed to be filed as part of this Form 10-K report as indicated under Items 1, 2 and 7. A narrative of the graphic and image information that appears in the paper format version of Exhibit 13 is included in the electronic Form 10-K document as an appendix to Exhibit 13.

In addition to the following information about each business activity, data about Murphy's operations, properties and business segments, including revenues by class of products and financial information by geographic area, are provided on pages 9 through 17, F-12, F-27 through F-29, F-33 through F-35, and F-37 of this Form 10-K report and on pages 5 through 13 of the 2003 Annual Report.

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

Exploration and Production

The Company's exploration and production business explores for and produces crude oil, natural gas and natural gas liquids worldwide.

During 2003, Murphy's principal exploration and production activities were conducted in the United States by wholly owned Murphy Exploration & Production Company-USA (Murphy Expro USA), and in Ecuador and Malaysia by wholly owned Murphy Exploration & Production Company-International (Murphy Expro International) and its subsidiaries, in western Canada and offshore eastern Canada by wholly owned Murphy Oil Company Ltd. (MOCL) and its subsidiaries, and in the U.K. North Sea and the Atlantic Margin by wholly owned Murphy Petroleum Limited. Murphy's crude oil and natural gas liquids production in 2003 was in the United States, Canada, the United Kingdom, Malaysia and Ecuador; its natural gas was produced and sold in the United States, Canada and the United Kingdom. MOCL owns a 5% undivided interest in Syncrude Canada Ltd. in Northern Alberta, the world's largest producer of synthetic crude oil.

Murphy's worldwide crude oil, condensate and natural gas liquids production in 2003 averaged 83,452 barrels per day, an increase of 9% compared to 2002. The increase was primarily due to the start-up of the West Patricia field in Block SK 309, offshore Sarawak, Malaysia. The Company's worldwide sales volume of natural gas averaged 215 million cubic feet per day in 2003, down 27% from 2002 levels. The main reason for the lower natural gas sales was a decline in production at the Ladyfern field in British Columbia, Canada. Natural gas sales were also lower in the U.S. in 2003 due to normal decline in Gulf of Mexico field production.

Total crude oil, condensate and natural gas liquids production is expected to increase in 2004 because of a full year of production at the West Patricia field offshore Malaysia and two deepwater Gulf of Mexico fields known as Medusa and Habanero. West Patricia started up in May 2003, while Medusa and Habanero came on line in November 2003. The Company anticipates first production from another deepwater Gulf of Mexico field named Front Runner in the second half of 2004. The Company announced in late 2003 that it intends to sell most of its conventional oil and gas properties in the Western Canadian Sedimentary Basin (WCSB). This sale will reduce 2004 production by about 20,000 net barrels of oil equivalent per day. Natural gas sales volumes are expected to decline in 2004 compared to 2003 as the higher production from the three deepwater Gulf of Mexico fields mentioned above will not offset the effect of the sale of western Canada properties and normal production declines in other areas.

In the United States, Murphy has production of oil and/or natural gas from 16 fields operated by the Company and 16 fields operated by others. Of the total producing fields at December 31, 2003, two are in the deepwater Gulf of Mexico, 24 are in more shallow waters on the Gulf of

Mexico continental shelf, five are onshore in Louisiana, and one is the Northstar field in Alaska. The Company's primary focus in the U.S. is in the deepwater Gulf of Mexico, which is generally defined as water depths of 1,000 feet or more. During the fourth quarter of 2003, the Company's first two deepwater fields came on production. The Company operates and owns a 60% interest in the Medusa field, in Mississippi Canyon Blocks 538/582. Peak net production from Medusa is expected to be 25,000 barrels of oil equivalent per day. The Company owns a 33.75% interest in the Habanero field in Garden Banks Block 341. Habanero, which is operated by Shell, should reach peak net production of 7,000 barrels of oil equivalent per day in 2004. Murphy has another deepwater discovery at the Front Runner field in Green Canyon Blocks 338/339 which is in development and should come on stream in the second half of 2004. Murphy owns 37.5% and operates the Front Runner field, which is expected to have peak net production of 20,000 barrels of oil equivalent per day. Murphy holds an interest in 173 blocks in the deepwater Gulf of Mexico, and expects to drill about four deepwater prospects per year over the next several years. The Company's two largest producing areas on the continental shelf of the Gulf of Mexico are the Tahoe field at Viosca Knoll Block 783 (30%) and South Timbalier Blocks 63/86 (100%/96%). Tahoe is operated by Shell and produced about 19 million cubic feet (MMCF) of natural gas per day and 500 barrels of oil per day net to the Company in 2003. Murphy operates South Timbalier Blocks 63/86 with a combined net production of about 1,000 barrels of oil per day and 13 MMCF per day in 2003. Onshore production, which is mostly natural gas, is primarily located on several leases in Vermilion Parish, Louisiana. Murphy's net production in 2003 from onshore fields was 30 MMCF per day. The Company owns approximately a 1.4% working interest in the Northstar field operated by BP in Alaska. Total net oil production for this field was approximately 700 barrels per day in 2003.

In Canada, the Company owns an interest in three legacy assets, the Hibernia and Terra Nova fields offshore Newfoundland and Syncrude Canada Ltd. In addition, the Company owned interests in several fields in the WCSB at the end of 2003. In December 2003, the Company announced its intent to sell most of these WCSB assets, while retaining a limited number of heavy oil and natural gas fields which are strategic to the Company. Assets to be sold produced about 20,000 barrels of oil equivalent per day in 2003 and had total proved reserves of approximately 46 million barrels of oil equivalent at the end of the year. The marketing of these assets has commenced in early 2004, with an anticipated sale in the second quarter. Murphy holds a 6.5% interest in Hibernia and a 12% interest in Terra Nova, with these being the first two fields on production in the Jeanne d'Arc Basin, offshore Newfoundland. Total net production in 2003 was 12,800 barrels of oil per day from Hibernia, which is operated by Hibernia Management and Development Company, while net production from Terra Nova, which is operated by PetroCanada, was 15,700 barrels of oil per day. Murphy owns a 5% undivided interest in Syncrude Canada Ltd., a joint venture located about 25 miles north of Fort McMurray, Alberta. Syncrude utilizes its assets to extract bitumen from oil sand deposits and to upgrade this bitumen into a high-value synthetic crude oil. Syncrude is currently expanding its facilities and is adding a third coker that will allow for increased production beginning in 2006. Total net production in 2003 was 10,500 barrels of crude oil per day, but should increase in 2004 due to improvements in operational efficiency. Although Syncrude produces a very high quality synthetic crude oil from bitumen, the U.S. Securities and Exchange Commission (SEC) does not allow the Company to include Syncrude's reserves in its proved oil reserves, which are reported on page F-31. The SEC considers Syncrude to be a mining operation, and not a conventional oil operation. Murphy and its partners have made a potential natural gas discovery at the Annapolis field, offshore Nova Scotia. An appraisal well is expected to be drilled in 2004 to determine whether this discovery has commercial size. Annapolis is operated by Marathon, and Murphy is a 19% owner in the block.

Murphy produces oil and natural gas in the United Kingdom sector of the North Sea. In 2003 the Company sold its interest in the Ninian and Columba fields. Production from these two fields averaged about 4,400 barrels per day in 2003 prior to the sale. The Company's primary oil production in the U.K. is now derived from two areas, Schiehallion and Mungo/Monan. Murphy owns 5.88% of the Schiehallion field operated by BP. This field is located in an area known as the Atlantic Margin and lies west of the Shetland Islands. Schiehallion produces oil into a Floating Production Storage and Offloading vessel (FPSO). The oil is transported via dedicated tanker to Sullom Voe terminal, where the oil is sold to third parties. Schiehallion produced approximately 5,700 net barrels of oil per day in 2003. Schiehallion development will continue with further infield drilling planned in 2005 onwards. Mungo/Monan is also operated by BP and is 12.65% owned by Murphy. The Mungo field produces through an unmanned platform, while Monan is produced through subsea facilities. Both the platform and subsea facilities are tied to a central processing facility that is linked to the Forties pipeline system. In 2003, the Mungo and Monan fields produced approximately 5,000 barrels of oil per day, net to Murphy's interest.

In Ecuador, Murphy owns a 20% working interest in Block 16, which is operated by Repsol YPF under a participation contract. In the second half of 2003, the start-up of the OCP pipeline, owned by other companies, enabled higher production from Block 16. However, inadequate water handling facilities combined with other operational issues have led to less than planned production from this field. Block 16 owners are evaluating alternatives for maximizing field production. The Company's net production was 5,200 barrels of oil per day in 2003; but exiting the year production totaled about 8,000 net barrels per day from the field. Due to utilization of the last foreign exchange loss carryforwards in the 2003 tax return, the Company expects to incur its first significant income tax liability in Ecuador beginning in 2004.

The Company has majority interests in eight separate production sharing contracts (PSCs) in Malaysia. The Company serves as the operator of all these areas, which cover approximately 14.4 million acres in total. Murphy has an 85% interest in two shallow water blocks, known as SK 309 and SK 311. The West Patricia field in Block SK 309, discovered in 2002, came on stream in May 2003. The Company's net share of production averaged about 10,700 barrels of oil per day in the fourth quarter of 2003. The Company made a major discovery at the Kikeh field in deepwater Block K in 2002 and added a discovery at Kikeh Kecil in 2003. Further exploration and appraisal drilling will occur in the 80% owned Block K in 2004. A development plan is in progress for the Kikeh field, and the Company expects that its Board of Directors and Malaysian authorities will approve the development plan in 2004. First production at Kikeh is currently expected in 2007. The Company drilled its first exploration well in its 80% owned Block H in 2003, but the well was unsuccessful. Murphy also owns 75% interests in Blocks PM 311 and PM 312, located offshore peninsular Malaysia. Murphy plans to commence its first exploration drilling on the peninsular Malaysia blocks in 2004. In early 2003, Malaysia awarded the Company interests in PSCs covering deepwater Blocks L (60%) and M (70%). The Sultanate of Brunei has also claimed this acreage. Murphy drilled a wildcat well in Block L in mid-2003. Well results have been kept confidential and well costs held in suspension. A total of 2.9 million gross acres associated with Blocks L and M have been included in the acreage table below.

The Company signed Production Sharing Agreements (PSAs) covering two offshore blocks in the Republic of Congo in 2003. The Company has an 85% interest in each PSA. These blocks cover approximately 1.8 million acres with water depths ranging from 490 to 6,900 feet. These blocks are named Mer Profonde Sud and Mer Profonde Nord. Murphy plans to drill its first exploration well on these blocks in 2004. Murphy has not included these net acres in its acreage table below pending the completion of statutory procedures required for final award of the acreage, which is expected to occur in 2004.

Murphy's estimated net quantities of proved oil and gas reserves and proved developed oil and gas reserves at December 31, 2000, 2001, 2002 and 2003 by geographic area are reported on pages F-31 and F-32 of this Form 10-K report. Murphy has not filed and is not required to file any estimates of its total net proved oil or gas reserves on a recurring basis with any federal or foreign governmental regulatory authority or agency other than the U.S. Securities and Exchange Commission. Annually, Murphy reports gross reserves of properties operated in the United States to the U.S. Department of Energy; such reserves are derived from the same data from which estimated net proved reserves of such properties are determined.

Net crude oil, condensate, and gas liquids production and sales, and net natural gas sales by geographic area with weighted average sales prices for each of the five years ended December 31, 2003 are shown on page 8 of the 2003 Annual Report.

Production expenses for the last three years in U.S. dollars per equivalent barrel are discussed on page 13 of this Form 10-K report. For purposes of these computations, natural gas sales volumes are converted to equivalent barrels of crude oil using a ratio of six thousand cubic feet (MCF) of natural gas to one barrel of crude oil.

Supplemental disclosures relating to oil and gas producing activities are reported on pages F-30 through F-37 of this Form 10-K report.

At December 31, 2003, Murphy held leases, concessions, contracts or permits on developed and undeveloped acreage as shown by geographic area in the following table. Gross acres are those in which all or part of the working interest is owned by Murphy. Net acres are the portions of the gross acres applicable to Murphy's working interest.

	Developed		Undeveloped		Total	
Area (Thousands of acres)[1]	Gross	Net	Gross	Net	Gross	Net
United States – Onshore	19	7	25	15	44	22
– Gulf of Mexico	21	6	1,241	848	1,262	854
– Alaska	4	–[2]	41	11	45	11
Total United States	44	13	1,307	874	1,351	887
Canada – Onshore	678	257	1,153	765	1,831	1,022
– Offshore	88	7	10,893	3,245	10,981	3,252
Total Canada	766	264	12,046	4,010	12,812	4,274
United Kingdom	50	6	449	111	499	117
Ecuador	7	1	524	105	531	106
Malaysia	2	2	14,431	11,100	14,433	11,102
Ireland	–	–	650	98	650	98
Spain	–	–	36	6	36	6
Totals	869	286	29,443	16,304	30,312	16,590
Oil sands – Syncrude	95	5	158	8	253	13

[1] Two production sharing agreements covering the Mer Profonde Nord and Mer Profonde Sud offshore blocks in the Republic of Congo were signed in 2003. The Company's 85% interest in the combined 1,773,365 undeveloped gross acres have not been included in this acreage table pending completion by the Republic of Congo of remaining statutory procedures.

[2] Less than one.

The only significant undeveloped acreage that expires in the next three years is approximately 4.2 million acres in Block K in Malaysia that is not included in the Kikeh discovery area. The Company is currently negotiating to extend the exploration rights for this acreage.

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

The following table shows the number of oil and gas wells producing or capable of producing at December 31, 2003.

	Oil Wells		Gas Wells	
Country	Gross	Net	Gross	Net
United States	182	47	121	34
Canada	722	517	780	359
United Kingdom	45	4	22	2
Malaysia	6	5	–	–
Ecuador	85	17	–	–
Totals	1,040	590	923	395
Wells included above with multiple completions and counted as one well each	21	9	47	26

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

	United States		Canada		United Kingdom		Malaysia		Ecuador and Other		Totals	
	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry
2003												
Exploratory	**2.5**	**2.4**	**10.4**	**9.4**	**–**	**–**	**.8**	**2.7**	**–**	**.1**	**13.7**	**14.6**
Development	**2.4**	**–**	**108.2**	**3.9**	**.2**	**.3**	**4.1**	**–**	**2.4**	**–**	**117.3**	**4.2**
2002												
Exploratory	1.0	3.2	8.8	4.1	–	.5	4.3	3.7	–	–	14.1	11.5
Development	2.2	–	45.5	3.9	.7	.2	3.4	–	3.4	–	55.2	4.1
2001												
Exploratory	6.9	1.7	27.3	12.1	–	–	1.0	2.0	–	–	35.2	15.8
Development	4.1	–	24.7	1.7	.6	.1	–	–	2.4	–	31.8	1.8

Murphy's drilling wells in progress at December 31, 2003 are shown below.

	Exploratory		Development		Total	
Country	Gross	Net	Gross	Net	Gross	Net
United States	1	.5	1	*	2	.5
Canada	4	2.5	7	2.8	11	5.3
Ecuador	–	–	1	.2	1	.2
Totals	5	3.0	9	3.0	14	6.0

*Less than 0.1.

Additional information about current exploration and production activities is reported on pages 6 through 10 of the 2003 Annual Report.

Refining and Marketing

The Company's refining and marketing businesses are located in North America and the United Kingdom, and primarily consist of operations that refine crude oil and other feedstocks into petroleum products such as gasoline and distillates, buy and sell crude oil and refined products, and transport and market petroleum products.

Murphy Oil USA, Inc. (MOUSA), a wholly owned subsidiary of Murphy Oil Corporation, owns and operates two refineries in the United States. The Meraux, Louisiana refinery is located on fee land and on two leases that expire in 2010 and 2021, at which times the Company has options to purchase the leased acreage at fixed prices. The refinery at Superior, Wisconsin is located on fee land. Murco Petroleum Limited (Murco), a wholly owned U.K. subsidiary serviced by Murphy Eastern Oil Company, has an effective 30% interest in a refinery at Milford Haven, Wales that can process 108,000 barrels of crude oil per day. Refinery capacities at December 31, 2003 are shown in the following table.

	Meraux, Louisiana	Superior, Wisconsin	Milford Haven, Wales (Murco's 30%)	Total
Crude capacity – b/sd*	125,000	35,000	32,400	192,400
Process capacity – b/sd*				
Vacuum distillation	50,000	20,500	16,500	87,000
Catalytic cracking – fresh feed	37,000	11,000	9,960	57,960
Naphtha hydrotreating	35,000	9,000	5,490	49,490
Catalytic reforming	32,000	8,000	5,490	45,490
Distillate hydrotreating	52,000	7,800	20,250	80,050
Hydrocracking	32,000	–	–	32,000
Gas oil hydrotreating	12,000	–	–	12,000
Solvent deasphalting	18,000	–	–	18,000
Isomerization	–	2,000	3,400	5,400
Production capacity – b/sd*				
Alkylation	8,500	1,500	1,680	11,680
Asphalt	–	7,500	–	7,500
Crude oil and product storage capacity – barrels	4,300,000	3,054,000	2,638,000	9,992,000

*Barrels per stream day.

The Company completed its expansion of the Meraux refinery in the fourth quarter 2003. The expansion allows the refinery to meet new low-sulfur gasoline specifications which become effective for the Company in 2008. The expansion included a new hydrocracker unit, central control room and two new utility boilers; expansion of the crude oil processing capacity to 125,000 barrels per stream day (b/sd); expansion of naphtha hydrotreating capacity to 35,000 b/sd; expansion of the catalytic reforming capacity to 32,000 b/sd; and construction of a new sulfur recovery complex, including amine regeneration, sour water stripping and high efficiency sulfur recovery. The Meraux plant has no solvent deasphalting processing capability at December 31, 2003 because of the fire in June 2003 that destroyed the Residual Oil Supercritical Extractor (ROSE) unit. The unit is being rebuilt, primarily using proceeds of property insurance, and should be operational in the fourth quarter 2004. While the ROSE unit is being rebuilt, the refinery will produce a larger volume of heavy fuel oil. The Company is in the process of building an FCC gasoline hydrotreater unit at its Superior, Wisconsin refinery, that is expected to be completed in late 2004. This unit will allow Superior to meet low-sulfur gasoline specifications.

MOUSA markets refined products through a network of retail gasoline stations and branded and unbranded wholesale customers in a 23-state area of the southern and midwestern United States. Murphy's retail stations are primarily located in the parking areas of Wal-Mart stores in 21 states and use the brand name Murphy USA®. Branded wholesale customers use the brand name SPUR®. Refined products are supplied from 12 terminals that are wholly owned and operated by MOUSA and numerous terminals owned by others. Of the wholly owned terminals, four are supplied by marine transportation, three are supplied by truck, two are adjacent to MOUSA's refineries and three are supplied by pipeline. MOUSA receives products at the terminals owned by others either in exchange for deliveries from the Company's terminals or by outright purchase. The Company sold its jointly owned terminals in early 2004. At December 31, 2003, the Company marketed products through 623 Murphy USA stations and 363 branded wholesale SPUR stations. MOUSA plans to add about 160 new Murphy USA stations at Wal-Mart sites in the southern and midwestern United States in 2004. In 2002, the Company and Wal-Mart reached an agreement for a Canadian subsidiary of the Company to market products through Murphy Canada™ stations at select Wal-Mart stores across Canada. The Company's subsidiary operates eight stations at Wal-Mart sites in Canada at December 31, 2003.

Murphy has master agreements that allow the Company to rent space in the parking lots of Wal-Mart stores in 21 states and in Canada for the purpose of building retail gasoline stations. The master agreements contain general terms applicable to all sites in the United States and Canada. As each individual station is constructed, an addendum to the master agreement is entered into, which contains the terms specific to that location. The terms of the agreements range from 10-15 years at each station, with Murphy holding two successive five-year extension options at each site. The agreements permit Wal-Mart to terminate the agreements in their entirety, or only as to affected sites, at its option for the following reasons: Murphy vacates or abandons the property; Murphy improperly transfers the rights under this agreement to another party; an agreement or a premises is taken upon execution or by process of law; Murphy files a petition in bankruptcy or becomes insolvent; Murphy fails to pay its debts as they become due; Murphy fails to pay rent or other sums required to be paid within 90 days after written notice; or Murphy fails to perform in any material way as required by the agreements. Sales from these stations amounted to 35.8% of total

Company revenues in 2003, 30.3% in 2002 and 22.5% in 2001. As the Company continues to expand the number of gasoline stations at Wal-Mart sites, total revenue generated by this business is expected to grow proportionately.

At the end of 2003, Murco distributed refined products in the United Kingdom from the Milford Haven refinery, three wholly owned terminals supplied by rail, six terminals owned by others where products are received in exchange for deliveries from the Company's terminals, and 384 branded stations under the brand names MURCO and EP.

Murphy owns a 20% interest in a 120-mile refined products pipeline, with a capacity of 165,000 barrels a day, that transports products from the Meraux refinery to two common carrier pipelines serving the southeastern United States. The Company also owns a 3.2% interest in LOOP LLC, which provides deepwater unloading accommodations off the Louisiana coast for oil tankers and onshore facilities for storage of crude oil. A crude oil pipeline with a diameter of 24 inches connects LOOP storage at Clovelly, Louisiana to the Meraux refinery. Murphy owns 29.4% of the first 22 miles of this pipeline from Clovelly to Alliance, Louisiana and 100% of the remaining 24 miles from Alliance to Meraux. The pipeline is connected to another company's pipeline system, allowing crude oil transported by that system to also be shipped to the Meraux refinery. In February 2002, the Company sold its 22% interest in a 312-mile crude oil pipeline in Montana and Wyoming for $7 million.

In May 2001, the Company sold its Canadian pipeline and trucking operation, including seven crude oil pipelines with various ownership percentages and capacities. Murphy realized an after-tax gain of $71 million on this sale.

Additional information about current refining and marketing activities and a statistical summary of key operating and financial indicators for each of the five years ended December 31, 2003 are reported on pages 11 through 13 of the 2003 Annual Report.

Employees

At December 31, 2003, Murphy had 4,789 employees – 2,103 full-time and 2,686 part-time.

Competition and Other Conditions Which May Affect Business

Murphy operates in the oil industry and experiences intense competition from other oil companies, which include state-owned foreign oil companies, major integrated oil companies, independent producers of oil and natural gas and independent refining companies. Virtually all of the state-owned and major integrated oil companies and many of the independent producers and independent refiners that compete with the Company have substantially greater resources than Murphy. In addition, the oil industry as a whole competes with other industries in supplying energy requirements around the world. Murphy is a net purchaser of crude oil and other refinery feedstocks, and also purchases refined products, particularly gasoline needed to supply its retail marketing stations located at Wal-Mart sites. The Company may be required to respond to operating and pricing policies of others, including producing country governments from whom it makes purchases. Additional information concerning current conditions of the Company's business is reported under the caption "Outlook" beginning on page 21 of this Form 10-K report.

In 2003, the Company's production of oil and natural gas represented approximately .1% of the respective worldwide totals. Murphy owned approximately 1% of the crude oil refining capacity in the United States and its market share of U.S. retail gasoline sales was slightly above 1%.

The operations and earnings of Murphy have been and continue to be affected by worldwide political developments. Many governments, including those that are members of the Organization of Petroleum Exporting Countries (OPEC), unilaterally intervene at times in the orderly market of crude oil and natural gas produced in their countries through such actions as setting prices, determining rates of production, and controlling who may buy and sell the production.

In addition, prices and availability of crude oil, natural gas and refined products could be influenced by political unrest and by various governmental policies to restrict or increase petroleum usage and supply. Other governmental actions that could affect Murphy's operations and earnings include tax changes and regulations concerning: currency fluctuations, protection and remediation of the environment (See the caption "Environmental" beginning on page 17 of this Form 10-K report), preferential and discriminatory awarding of oil and gas leases, restrictions on drilling and/or production, restraints and controls on imports and exports, safety, and relationships between employers and employees. Because these and other factors too numerous to list are subject to constant changes caused by governmental and political considerations and are often made in great haste in response to changing internal and worldwide economic conditions and to actions of other governments or specific events, it is not practical to attempt to predict the effects of such factors on Murphy's future operations and earnings.

Murphy's business is subject to operational hazards and risks normally associated with the exploration for and production of oil and natural gas and the refining and marketing of crude oil and petroleum products. The occurrence of an event, including but not limited to acts of nature, mechanical equipment failures, industrial accidents, fires and intentional attacks could result in the loss of hydrocarbons and associated revenues, environmental pollution or contamination, and personal injury or bodily injury, including death, for which the Company could be deemed to be liable, and could subject the Company to substantial fines and/or claims for punitive damages. Murphy maintains insurance against certain, but not all, hazards that could arise from its operations, and such insurance is believed to be reasonable for the hazards and risks faced by the Company. As of December 31, 2003, the Company maintained total excess liability insurance with limits of $500 million per occurrence covering employees, general liability and certain "sudden and accidental" environmental risks. The Company also maintained insurance coverage with an additional limit of $250 million per occurrence, all or part of which could be applicable to certain gradual and/or sudden and accidental pollution events. There can be no assurance that such insurance will be adequate to offset lost revenues or costs associated with certain events or that insurance coverage will continue to be available in the future on terms that justify its purchase. The occurrence of an event that is not fully insured could have a material adverse effect on the Company's financial condition and results of operations in the future.

Executive Officers of the Registrant

The age at January 1, 2004, present corporate office and length of service in office of each of the Company's executive officers are reported in the following listing. Executive officers are elected annually but may be removed from office at any time by the Board of Directors.

Claiborne P. Deming – Age 49; President and Chief Executive Officer since October 1994 and Director and Member of the Executive Committee since 1993. He served as Executive Vice President and Chief Operating Officer from 1992 to 1993 and President of MOUSA from 1989 to 1992.

Steven A. Cossé – Age 56; Senior Vice President since October 1994 and General Counsel since August 1991. Mr. Cossé was elected Vice President in 1993. For the eight years prior to August 1991, he was General Counsel for Ocean Drilling & Exploration Company (ODECO), a majority-owned subsidiary of Murphy.

W. Michael Hulse – Age 50; Executive Vice President – Worldwide Downstream Operations effective April 2003. Mr. Hulse has been President of MOUSA from November 2001 to present. He served as President of Murphy Eastern Oil Company from April 1996 to November 2001.

Bill H. Stobaugh – Age 52; Vice President since May 1995, when he joined the Company. Prior to that, he had held various engineering, planning and managerial positions, the most recent being with an engineering consulting firm.

Kevin G. Fitzgerald – Age 48; Treasurer since July 2001. Mr. Fitzgerald was Director of Investor Relations from 1996 to June 2001, and also served in various capacities with the Company and ODECO between 1982 and 1996.

John W. Eckart – Age 45; Controller since March 2000. Mr. Eckart had been Assistant Controller since February 1995 after joining the Company as Auditing Manager in 1990.

Walter K. Compton – Age 41; Secretary since December 1996. He became Manager, Law Department, in November 1996, and has been an attorney with the Company since 1988.

Item 3. 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$3.61 billion. The Company believes that the counterclaim is without merit and that the amount of damages sought is frivolous. Trial will likely begin in January 2005. 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, 17 class action lawsuits have been filed seeking damages for area residents. All the lawsuits have been administratively consolidated into a single legal action. The Company maintains liability insurance that covers such matters, and it recorded the applicable insurance deductible as an expense in 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 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of security holders during the fourth quarter of 2003.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The Company's Common Stock is traded on the New York Stock Exchange using "MUR" as the trading symbol. There were 2,839 stockholders of record as of December 31, 2003. Information as to high and low market prices per share and dividends per share by quarter for 2003 and 2002 are reported on page F-38 of this Form 10-K report.

Item 6. SELECTED FINANCIAL DATA

(Thousands of dollars except per share data)	2003	2002	2001	2000	1999
Results of Operations for the Year					
Sales and other operating revenues	**$5,275,099**	$3,966,516	$3,743,986	$3,630,195	$2,076,103
Net cash provided by continuing operations	**652,278**	526,969	630,631	738,083	332,455
Income from continuing operations	**301,190**	97,510	328,430	298,526	113,980
Net income	**294,197**	111,508	330,903	296,828	119,707
Per Common share – diluted					
Income from continuing operations	**3.25**	1.06	3.60	3.30	1.27
Net income	**3.17**	1.21	3.63	3.28	1.33
Cash dividends per Common share	**.80**	.775	.75	.725	.70
Percentage return on					
Average stockholders' equity	**16.4**	7.3	23.5	26.4	12.3
Average borrowed and invested capital	**11.0**	5.8	17.7	20.3	9.7
Average total assets	**6.7**	3.9	10.2	11.2	5.2
Capital Expenditures for the Year					
Continuing operations					
Exploration and production	**$ 762,682**	$ 631,799	$ 680,100	$ 392,732	$ 295,906
Refining and marketing	**215,362**	234,714	175,186	153,750	88,075
Corporate and other	**1,120**	1,136	5,806	11,415	2,572
	979,164	867,649	861,092	557,897	386,553
Discontinued operations	**–**	451	3,348	–	52
	$ 979,164	$ 868,100	$ 864,440	$ 557,897	$ 386,605
Financial Condition at December 31					
Current ratio	**1.28**	1.19	1.07	1.10	1.22
Working capital	**$ 228,529**	$ 136,268	$ 38,604	$ 71,710	$ 105,477
Net property, plant and equipment	**3,530,800**	2,886,599	2,525,807	2,184,719	1,782,741
Total assets	**4,712,647**	3,885,775	3,259,099	3,134,353	2,445,508
Long-term debt	**1,090,307**	862,808	520,785	524,759	393,164
Stockholders' equity	**1,950,883**	1,593,553	1,498,163	1,259,560	1,057,172
Per share	**21.24**	17.38	16.53	13.98	11.75
Long-term debt – percent of capital employed	**35.5**	35.1	25.8	29.4	27.1

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

Overview

Murphy Oil Corporation is a worldwide oil and gas exploration and production company with refining and marketing operations in North America and the United Kingdom. A more detailed description of the Company's significant assets can be found in Items 1 and 2 of this Form 10-K report.

Murphy generates revenue primarily by selling its oil and natural gas production and its refined petroleum products to third parties at hundreds of locations in the United States, Canada and other countries. The Company's revenue is highly affected by the prices of oil, natural gas and refined petroleum products it sells. Also, because crude oil is purchased by the Company for refinery feedstocks, natural gas is purchased for fuel at its refineries and oil fields, and gasoline is purchased to supply its retail gasoline stations in North America that are primarily located at Wal-Mart stores, the purchase prices for these commodities also have a significant effect on the Company's costs. In order to make a profit and generate cash in its exploration and production business, revenue generated from the sales of oil and natural gas produced must exceed the combined costs of producing these products, amortization of capital expenditures and expenses related to exploration. Profits and generation of cash in the Company's downstream operations are dependent upon achieving an adequate margin, which is determined by the sales prices for refined petroleum products less the costs of refinery feedstocks and gasoline purchases and expenses associated with manufacturing, transporting and marketing these products. Murphy also incurs certain costs for general company administration and for capital borrowed from lending institutions.

In general, worldwide oil prices and North American natural gas prices were stronger in 2003 than in 2002. The average price for West Texas Intermediate crude oil in 2003 was $31.00, an increase of 18% compared to 2002. The NYMEX natural gas price averaged $5.49 in 2003, up 63% over 2002. These price improvements were a significant factor leading to higher profits in the Company's exploration and production business in 2003 compared to the prior year. The Company did not fully benefit from the higher prices in 2003, because approximately 30% of its 2003 oil and natural gas production was hedged at prices that were lower than actual market prices in 2003. In addition, the higher prices for crude oil were a contributing factor to low refining and marketing margins in North America during a portion of 2003. If the prices for crude oil and natural gas decline significantly in 2004 or beyond, the Company would expect this to have an unfavorable impact on operating profits for its exploration and production business. Such lower oil and gas prices could, but may not, have a favorable impact on the Company's refining and marketing operating profits.

Results of Operations

The Company reported net income in 2003 of $294.2 million, $3.17 per diluted share, compared to net income in 2002 of $111.5 million, $1.21 per diluted share. In 2001 the Company earned $330.9 million, $3.63 per diluted share. The higher net income in 2003 compared to 2002 was caused by a combination of better earnings in the Company's exploration and production operations, a lower loss in refining and marketing operations, and lower net costs for corporate functions. The income reduction in 2002 compared to 2001 was due to lower earnings in the exploration and production business, significantly lower earnings in the refining and marketing area, and higher net costs for corporate functions. Further explanations of each of these variances are found in the following sections.

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. Upon adoption of SFAS No. 143, the Company recorded an expense of $7 million, net of $1.4 million in income taxes, as the cumulative effect of a change in accounting principle. Further explanation of this accounting change is included in Note B to the consolidated financial statements. Income before the cumulative effect of a change in accounting principle was $301.2 million ($3.25 per share) in 2003, $111.5 million ($1.21 per share) in 2002, and $330.9 million ($3.63 per share) in 2001.

In December 2002 the Company sold its interest in Ship Shoal Block 113 in the Gulf of Mexico. The results of operations for Ship Shoal Block 113 have been reflected as discontinued operations in 2002 and 2001 in accordance with Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. Therefore, the gain on disposal of $10.6 million in 2002 and other operating results of the field have been included net of income tax expense as Discontinued Operations in the consolidated statements of income for the years ended December 31, 2002 and 2001. Income from continuing operations was $301.2 million ($3.25 per share) in 2003, $97.5 million ($1.06 per share) in 2002, and $328.4 million ($3.60 per share) in 2001.

2003 vs. 2002 – Net income in 2003 was $294.2 million, $3.17 per diluted share, compared to $111.5 million, $1.21 per diluted share, in 2002. The 2003 period included an after-tax expense of $7 million, $.08 per share, related to a cumulative effect of a change in accounting principle associated with adoption of SFAS No. 143, Accounting for Asset Retirement Obligations. The 2002 period included profit on discontinued operations of $14 million, $.15 per share. Excluding the accounting change in 2003 and the results of discontinued operations in 2002, income from continuing operations was $301.2 million, $3.25 per share, in 2003, and $97.5 million, $1.06 per share, in 2002. The $203.7 million higher income from continuing operations in 2003 compared to 2002 was attributable to $165.2 million higher earnings from exploration and production operations, a $28.7 million lower loss from refining and marketing operations and a $9.8 million lower net cost of corporate activities. Earnings from exploration and production operations were up in 2003 primarily due to higher oil and natural gas sales prices, a $34 million after-tax gain on sale of the Ninian and Columba fields in the U.K. North Sea, record levels of oil production, higher tax benefits from settlement and rate adjustments, and lower property impairment and exploration expenses. Sales of natural gas were down significantly in 2003 primarily due to lower gas production in Canada. Refining and marketing results in both North America and the United Kingdom showed significant improvements in 2003. Most of the improvement in North America was generated by stronger margins in the retail marketing portion of the business. Higher margins in the U.K. led to better income from this area. The net costs of corporate activities were lower in 2003 primarily due to higher corporate income tax benefits related to settlement of prior year tax matters and lower net interest costs, partially offset by higher selling and general expenses.

Sales and other operating revenues in 2003 increased by $1.3 billion compared to 2002 due to higher sales volumes for crude oil and refined petroleum products, higher sales prices for oil, natural gas and refined products, and higher merchandise sales at retail gasoline stations. Gain on sale of assets was $52.4 million higher in 2003 primarily due to a $50 million pretax profit on sale of the Ninian and Columba fields in the U.K. North Sea. Crude oil, natural gas and product purchases expense increased by $975.9 million in 2003 due to higher costs of crude oil used for refinery feedstock, and higher costs and volumes of gasoline and merchandise purchased for sale at the Company's retail gasoline stations. Operating expenses increased by $86.7 million in 2003 due to higher operating and repair costs at refineries and higher operating costs at the Company's growing retail gasoline station chain. Selling and general expenses rose by $28 million in 2003 primarily due to higher retirement and incentive compensation expenses and higher costs for Malaysian operations. Exploration expenses were $8.3 million lower in 2003 mostly due to less exploratory costs incurred in Malaysia. Depreciation, depletion and amortization expense increased by $28.5 million in 2003 due to new production from the West Patricia field, offshore Sarawak Malaysia, and higher depreciation associated with the Company's growing retail gasoline station chain. Impairment of long-lived assets was $23.3 million lower in 2003 as the prior year included costs related to write-off of Destin Dome Blocks 56 and 57, offshore Florida. The 2003 statement of income included $12.4 million for accretion on discounted abandonment liabilities following the adoption of SFAS No. 143 on January 1, 2003. Because the abandonment liabilities are carried on the balance sheet at a discounted fair value, accretion must be recorded annually so that the liability will be recorded at full value at the time the abandonment occurs. Interest expense rose by $6.2 million in 2003 due to higher average borrowings under long-term debt during the year. The portion of interest capitalized increased by $12.7 million due to higher capital expenditures for development of deepwater Gulf of Mexico fields and expansion projects at Syncrude and the Meraux refinery. Income tax expense was $63.8 million more in 2003 mostly caused by higher pretax earnings, the effects of which were partially offset by a $20.1 million benefit from settlement of prior year tax audits in the U.S., an $11.8 million benefit related to enacted tax rate reductions in Canada, and an $11.4 million credit from recognition of deferred tax benefits in Malaysia.

2002 vs. 2001 – Income from continuing operations in 2002 was $97.5 million, $1.06 per share, compared to $328.4 million, $3.60 per share, in 2001. Lower income in 2002 of $230.9 million was mainly due to a $193.6 million reduction in refining and marketing results, caused by both weaker refining margins in 2002 compared to 2001 in the U.S. and U.K., and a $71 million gain in 2001 from sale of Canadian pipeline and trucking operations. Earnings from the Company's exploration and production activities were $26.5 million lower in 2002 than in 2001 as higher oil production, record levels of natural gas production and higher average oil sales prices were more than offset by lower natural gas sales prices, higher charges for property impairments and higher production and depreciation expenses.

Sales and other operating revenues were $222.5 million higher in 2002 than in 2001 due to higher crude oil production, record sales of natural gas, and higher sales volumes for refined products in North America and the United Kingdom. Gain on sale of assets declined by $96.4 million primarily due to the sale of Canadian pipeline and trucking assets in 2001. Interest and other income was $7.8 million lower in 2002 due to less interest earned on invested cash. Crude oil, natural gas and product purchases expense increased by $305.5 million in 2002 due to more purchases of finished products for retail marketing operations and a higher average purchase price for these products than in 2001. Operating expenses rose by $60.7 million mainly due to higher oil and natural gas production, higher maintenance costs for oil and gas producing fields and $5 million of costs to repair uninsured damage from tropical storms in the Gulf of Mexico. Depreciation, depletion and amortization expense increased $73.4 million in 2002 due to higher oil and natural gas production and more retail gasoline stations. Interest expense was $12.2 million more in 2002 due to higher average long-term borrowings than in 2001, including the sale of 10-year notes with a stated rate of 6.375% in 2002. Capitalized interest increased by $4.3 million due to ongoing projects to develop deepwater Gulf of Mexico fields, expand Syncrude, and build a hydrocracker and expand crude oil throughput capacity at the Meraux refinery. Income tax expense fell by $119.5 million essentially in line with lower pretax income from continuing operations.

In the following table, the Company's results of operations for the three years ended December 31, 2003 are presented by segment. More detailed reviews of operating results for the Company's exploration and production and refining and marketing activities follow the table.

(Millions of dollars)	**2003**	2002	2001
Exploration and production			
United States	**$ 23.3**	$ (11.8)	$ 55.3
Canada	**189.0**	157.0	85.5
United Kingdom	**95.3**	49.6	78.6
Ecuador	**16.7**	12.0	11.5
Malaysia	**10.7**	(43.0)	(36.1)
Other	**(8.8)**	(2.8)	(7.3)
	326.2	161.0	187.5
Refining and marketing			
North America	**(21.2)**	(39.2)	139.6
United Kingdom	**10.0**	(.7)	14.1
	(11.2)	(39.9)	153.7
Corporate and other	**(13.8)**	(23.6)	(12.8)
Income from continuing operations	**301.2**	97.5	328.4
Discontinued operations	**–**	14.0	2.5
Income before cumulative effect of change in accounting principle	**301.2**	111.5	330.9
Cumulative effect of change in accounting principle	**(7.0)**	–	–
Net income	**$294.2**	$111.5	$330.9

Exploration and Production – Earnings from exploration and production operations were $326.2 million in 2003, $161 million in 2002 and $187.5 million in 2001. The improvement in earnings in 2003 was primarily caused by a 7% higher realized worldwide oil sales price, a 64% higher realized natural gas sales price in North America, record crude oil production that was 9% higher than in 2002, a $34 million after-tax gain on sale of the Ninian and Columba fields in the U.K. North Sea, higher tax benefits from settlements and rate adjustments, and lower expenses related to property impairments and exploration. Natural gas sales volumes were 27% lower in 2003, primarily due to a decline in production at the Ladyfern field in Canada. Higher oil production was mostly attributable to start up in May 2003 of the West Patricia field, offshore Sarawak Malaysia. The reduction in property impairment expense in 2003 was primarily related to the write-off of the remaining costs for Destin Dome Blocks 56 and 57, offshore Florida, in 2002. The decline in exploration expenses was mostly attributable to lower exploratory costs in Malaysia.

Lower earnings in 2002 compared to 2001 was caused by a 24% lower average natural gas sales price in North America, higher costs associated with property impairments and higher production and depreciation expenses. The unfavorable effects of these items were partially offset by higher production of crude oil, record levels of natural gas sales, and a 10% higher average sales price for crude oil and condensate. Oil production from continuing operations increased by 13% in 2002 and natural gas production from continuing operations rose by 5%. Higher property impairment expense in 2002 was mostly related to the write-off of remaining costs for Destin Dome Blocks 56 and 57, offshore Florida.

The results of operations for oil and gas producing activities for each of the last three years are shown by major operating areas on pages F-34 and F-35 of this Form 10-K report. Daily production and sales rates and weighted average sales prices are shown on page 8 of the 2003 Annual Report.

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

(Millions of dollars)	**2003**	2002	2001
United States			
Oil and gas liquids	**$ 39.2**	$ 30.0	$ 38.5
Natural gas	**158.3**	111.3	192.8
Canada			
Conventional oil and gas liquids	**353.3**	304.8	167.2
Natural gas	**203.8**	197.6	182.6
Synthetic oil	**95.7**	106.3	95.8
United Kingdom			
Oil and gas liquids	**158.6**	163.0	181.5
Natural gas	**12.2**	7.0	12.1
Malaysia – crude oil	**77.7**	–	–
Ecuador – crude oil	**41.9**	30.7	33.4
Total oil and gas revenues	**$1,140.7**	$950.7	$903.9

The Company's crude oil, condensate and natural gas liquids production from continuing operations averaged 83,452 barrels per day in 2003, 75,213 barrels in 2002 and 66,344 barrels in 2001. Oil production in 2003 was a new annual record for Murphy Oil. Oil production from continuing operations in the United States increased 10% to 4,526 barrels per day. Production from two new deepwater Gulf of Mexico fields – Medusa and Habanero – that came on stream in November 2003 more than offset production declines from mature fields. Oil production in Canada increased 7% in 2003 to a record volume of 51,767 barrels per day. The 2003 production increase was primarily related to higher volumes produced offshore Newfoundland at the Terra Nova and Hibernia fields. Production at Terra Nova increased 26% and averaged 15,712 barrels per day in 2003. Hibernia production increased by 11% to 12,822 barrels per day in 2003. Net production from the synthetic oil operation known as Syncrude fell 879 barrels per day, or 8%, in 2003 due to less efficient operations caused by more downtime for repairs. Production of light oil decreased 568 barrels per day, or 17%, due to continued field decline and various property sales during the year. Heavy oil production in Canada increased 478 barrels per day, or 5%, during 2003 due to the results of development drilling, which was partially offset by lower production from various properties sold during the year. U.K. production was down by 3,616 barrels per day, or 20%, primarily due to sale of the Ninian and Columba fields in mid-2003 and production decline at the Mungo/Monan field. The Company produced 5,172 barrels of oil per day in Ecuador, 14% higher than in 2002, primarily due to a new heavy oil pipeline that began operations in the last half of 2003. Production began at the Company's West Patricia field in Block SK 309, offshore Sarawak Malaysia, in May 2003. Net production from West Patricia averaged 7,301 barrels per day for all 2003, but averaged over 11,000 barrels per day since start-up.

During 2002, oil production from continuing operations in the United States declined 13% compared to 2001 and averaged 4,128 barrels per day. The reduction was due to declines from existing fields in the Gulf of Mexico. Oil production in Canada increased 34% in 2002 to 48,239 barrels per day. The Company's share of net production at its synthetic oil operation improved 883 barrels per day, or 8%, in 2002 due to a combination of higher gross production and a lower net profit royalty caused by increased capital spending related to an ongoing expansion project. Production of light oil decreased 982 barrels per day, or 23%, and heavy oil production decreased 19% to 9,484 barrels per day in 2002 with both decreases primarily due to declines at existing Western Canada fields. Production at Hibernia rose 21% in 2002 to 11,574 barrels per day due to better operating efficiency, primarily associated with improved handling of gas production. The Terra Nova field started up in January 2002 and averaged 12,463 barrels per day in 2002. U.K. production was down by 1,912 barrels per day, or 9%, in 2002 primarily due to declines from the Company's "T" Block and Ninian fields in the North Sea. Oil production in Ecuador was 15% lower than 2001 and totaled 4,544 barrels per day. This reduction was caused by more pipeline constraints, which forced the operation to limit daily production.

Worldwide sales of natural gas from continuing operations were 215.3 million cubic feet per day in 2003, 292.9 million in 2002 and 278.3 million in 2001. The total for 2002 was a Company record for natural gas sales. Sales of natural gas in the United States were 82.3 million cubic feet per day in 2003, 88.1 million in 2002 and 112.6 million in 2001. The reductions in 2003 and 2002 were due to lower deliverability from mature fields in the Gulf of Mexico. Natural gas sales in Canada fell from a record level of 197.9 million cubic feet per day in 2002 to 123.5 million in 2003. The 38% reduction in 2003 was mostly caused by a steep production decline at the Ladyfern field. Canadian natural gas sales had increased 30% in 2002 due to higher production from the Ladyfern field. Natural gas sales in the United Kingdom were 9.6 million cubic feet per day in 2003, up 37% compared to 2002. U.K. natural gas sales in 2002 decreased 47% compared to 2001 levels and totaled 7 million cubic feet per day. The change in U.K. sales in each year was due primarily to the level of sales nominations at the Amethyst field in the North Sea.

Worldwide crude oil sales prices were higher in 2003 than in 2002 due to a strengthening world economy and effective production output controls by OPEC producers. The Company's average realized sales price for crude oil and condensate was $25.27 per barrel in 2003 compared to $23.59 in 2002. The worldwide average price was reduced $2.25 per barrel by the effects of the Company's 2003 hedging program. The Company had hedged the sales price in 2003 for most of its heavy oil production in Canada and light oil production in the U.S., as well as a portion of its offshore and synthetic crude production in Canada. The U.S. average crude oil sales price was essentially flat with 2002 and averaged $24.22 per barrel. Light oil production in Canada was sold at an average of $27.39 per barrel in 2003, up 21% from 2002. Heavy Canadian oil sold at $12.34 per barrel in 2003, 27% lower than in 2002. The average 2003 sales prices for offshore and synthetic oil production in Canada were $27.08 per barrel and $24.97 per barrel, respectively. Offshore prices were 7% higher than 2002, but synthetic crude was lower by 3%. The average sales price in the U.K. increased by 21% to $29.59 per barrel. Ecuador production was sold at an average of $22.99 per barrel, which was 17% above the average for 2002. New production from the West Patricia field in Malaysia brought an average of $29.42 per barrel in 2003.

The average sales price for light crude oil in 2002 was comparable to 2001; however, heavy oil prices were significantly stronger in comparison to light oil prices during the year. In the United States, the Company's average monthly sales price for crude oil and condensate declined 3% compared to 2001 and averaged $24.25 per barrel for the year. In Canada, the sales price for light oil rose 1% to $22.60 per barrel. Heavy oil prices in Canada averaged $16.82 per barrel, up 52% from 2001. The sales price for crude oil from the Hibernia field rose 7% to $25.34 per barrel. The average sales price for oil from the new Terra Nova field was $25.38 per barrel. Synthetic oil prices in 2002 were $25.64 per barrel, up 2% from the prior year. Sales prices in the U.K. were about flat with 2001 at $24.39 per barrel and sales prices in Ecuador were up 16% to $19.64 per barrel.

The sales prices for natural gas were much stronger in 2003 than in 2002 as high demand coupled with a tight supply buoyed prices. The average sales price realized by the Company in North America in 2003 was 64% higher than in 2002 and averaged $4.83 per thousand cubic feet (MCF) for the year. This price was reduced by $.17 per MCF because of the Company's hedging program in the U.S. and Canada. In the U.S., natural gas sales prices averaged $5.29 per MCF in 2003, up 57% compared to 2002. Canadian gas prices increased 65% to an average of $4.52 per MCF. Natural gas was sold in the U.K. at an average of $3.50 per MCF, 27% higher than the 2002 average.

During 2002, the Company's North American natural gas sales prices were weaker than in 2001 generally due to a warmer than normal winter. Natural gas sales prices in North America decreased 24% from 2001 and averaged $2.94 per MCF in 2002 compared to $3.87 in the prior year. U.S. natural gas sales prices decreased 27% in 2002 and averaged $3.37 per MCF compared to $4.64 in the prior year. Canadian natural gas production was sold in 2002 at an average price of $2.74 per MCF, 16% lower than in 2001. The sales price for natural gas sold in the United Kingdom increased 10% to $2.76 per MCF.

Based on 2003 volumes and deducting taxes at marginal rates, each $1 per barrel and $.10 per MCF fluctuation in prices would have affected earnings from exploration and production operations by $19.7 million and $4.6 million, respectively. The effect of these price fluctuations on consolidated net income cannot be measured because operating results of the Company's refining and marketing segments could be affected differently.

Production expenses were $234.2 million in 2003, $229.6 million in 2002 and $211 million in 2001. These amounts are shown by major operating area on pages F-34 and F-35 of this Form 10-K report. Costs per equivalent barrel excluding discontinued operations during the last three years are shown in the following table.

(Dollars per equivalent barrel)	**2003**	2002	2001
United States	**$ 5.54**	$ 5.64	$ 4.82
Canada			
Excluding synthetic oil	**3.59**	3.48	3.84
Synthetic oil	**16.43**	11.75	13.58
United Kingdom	**4.69**	5.03	3.75
Malaysia	**3.44**	–	–
Ecuador	**9.05**	8.17	7.60
Worldwide – excluding synthetic oil	**4.33**	4.29	4.24

The lower costs in the United States in 2003 were due to both higher production and less well servicing costs. The increase in the cost per equivalent barrel in the U.S. in 2002 was attributable to a combination of lower production and more well servicing. Higher average Canadian costs excluding synthetic oil in 2003 was caused by lower natural gas production and a higher average foreign exchange rate. The lower average cost in 2002 for Canada, excluding synthetic oil, was due to higher natural gas production volumes and new production from the Terra Nova field, offshore Newfoundland. The increase in unit costs for Canadian synthetic oil operations in 2003 was attributable to a combination of lower production, higher maintenance costs and a higher foreign exchange rate. The lower average cost per barrel for Canadian synthetic oil in 2002 was due to a combination of lower maintenance costs and higher net production. Lower average costs in the U.K. in 2003 was mainly due to the sale of the high-cost Ninian and Columba fields in the second quarter. The increase in average costs in the U.K. in 2002 was due to both higher costs to maintain mature properties, primarily at the Ninian field, and lower overall production. Production expense increases per unit in Ecuador in 2003 were mostly attributable to higher transportation costs associated with the new heavy oil pipeline. Higher costs per unit in Ecuador in 2002 were due to lower oil production compared to the previous year.

Exploration expenses for each of the last three years are shown in total in the following table, and amounts are reported by major operating area on pages F-34 and F-35 on this Form 10-K report. Certain of the expenses are included in the capital expenditures total for exploration and production activities.

(Millions of dollars)	**2003**	2002	2001
Exploration and production			
Dry holes	**$ 82.5**	$101.2	$ 82.8
Geological and geophysical	**34.0**	23.4	36.0
Other	**7.4**	10.2	15.0
	123.9	134.8	133.8
Undeveloped lease amortization	**27.2**	24.6	23.1
Total exploration expenses	**$151.1**	$159.4	$156.9

Dry hole costs were $18.7 million lower in 2003 than 2002 primarily due to more drilling success in deepwater Malaysia blocks. The $18.4 million increase in dry hole costs in 2002 was caused by higher costs for unsuccessful exploration drilling wells in the deep waters of the Gulf of Mexico and Malaysia, which were offset in part by lower costs in 2002 for wells off the east coast of Canada. Geological and geophysical expenses were up $10.6 million in 2003 mostly due to 3D seismic acquisition and processing in Blocks SK 309 and PM 311 in Malaysia. Geological and geophysical costs were down $12.6 million in 2002 due to less spending for 3D seismic on deepwater concessions in Malaysia. Other exploration expenses were $2.8 million lower in 2003 because more administrative costs in Malaysia were charged to the production department after start-up of West Patricia field production in May. Other exploration expenses were $4.8 million lower in 2002 primarily due to more charges to the Company's partner in Malaysia. Undeveloped leasehold amortization increased by $2.6 million in 2003 and $1.5 million in 2002 primarily because of lease acquisitions in each year in the Gulf of Mexico and Western Canada.

A total cost of $5 million was incurred in 2002 to repair equipment and well damages caused by tropical storms in the Gulf of Mexico. These costs essentially represent amounts not recovered through insurance policies.

Depreciation, depletion and amortization expense related to exploration and production operations totaled $268.2 million in 2003, $247.2 million in 2002 and $181.1 million in 2001. The $21 million increase in 2003 compared to 2002 was caused primarily by start-up of the West Patricia field in 2003. Higher costs of $66.1 million in 2002 were caused by higher oil and natural gas production, including start-up of the Terra Nova field in January 2002 and more production from the Ladyfern field in Western Canada.

The exploration and production business recorded $12.3 million of expense in 2003 for accretion on discounted abandonment liabilities following the adoption of SFAS No. 143 on January 1, 2003. Because the abandonment liabilities are carried on the balance sheet at a discounted fair value, accretion must be recorded annually so that the liability will be recorded at full value at the projected time of abandonment.

Property impairments occurred in the United States in each of the three years ended December 31, 2003. The amount of impairments in 2002 was significantly higher than 2003 and 2001 because the Company wrote off its remaining investment of $22.5 million in Destin Dome Blocks 56 and 57, offshore Florida. Based on an agreement with the U.S. government, the Company may not seek approval for development of this significant natural gas discovery until at least 2012.

The effective income tax rate for exploration and production operations was 32.9% in 2003, 38.4% in 2002 and 39.9% in 2001. The lower rate in 2003 was attributable to several factors. The Company sold its interests in the Ninian and Columba fields in 2003. Profits on these fields were assessed Petroleum Revenue taxes in addition to normal corporation taxes; thus the sale of these fields reduced the overall effective tax rate in the U.K. In addition, the Company recorded an $11.4 million deferred tax credit in 2003 to recognize anticipated future tax benefits on previously incurred expenses related to Blocks SK 309 and 311 in Malaysia. These benefits had not been recognized in the income statement in previous years because the Company had established a deferred tax valuation allowance until such time that it became probable that these expenses would be used to offset future taxable income. Also in 2003, both the Federal and Alberta governments of Canada reduced their tax rates for oil and gas companies. The rate reductions led to recognition of an $11.8 million tax benefit, mostly related to a reduction in deferred income tax liabilities. The effective tax rate in 2002 was lower than in 2001 primarily due to higher benefits in the latter year from settlement of prior-year tax matters.

Approximately 69% of the Company's U.S. proved oil reserves and 39% of the U.S. proved natural gas reserves are undeveloped. At December 31, 2003, about 93% of the total U.S. undeveloped reserves on a barrel of oil equivalent basis relate to deepwater Gulf of Mexico fields, including Medusa, Habanero and Front Runner. The Medusa and Habanero fields came on stream in November 2003 and a portion of the wells were not completed and/or producing at year-end. Front Runner is currently projected to produce first oil in the second half of 2004. In addition, 73% of oil reserves in Block SK 309 in Malaysia are undeveloped, pending further development drilling in future years. On a worldwide basis, the Company has spent approximately $280 million in 2003, $239 million in 2002 and $208 million in 2001 to develop proved reserves. The Company expects to spend about $220 million in 2004, $118 million in 2005 and $66 million in 2006 to move currently undeveloped proved reserves to the developed category.

The U.S. Securities and Exchange Commission (SEC) has obtained information from Murphy and other oil and gas companies operating in the Gulf of Mexico to assess how the industry is determining proved reserves related to new field discoveries. SEC regulations allow oil companies to recognize proved reserves if economic producibility is supported by either an actual production test or a conclusive formation test. In the absence of a production test, compelling technical data must exist to recognize proved reserves related to the initial discovery of the oil or natural gas field. Production tests in deepwater environments are extremely expensive and the oil industry has increasingly depended on advanced technical testing to support economic producibility. Murphy has recorded proved reserves related to four deepwater Gulf of Mexico fields based on conclusive formation tests rather than actual production tests. At the end of 2003, proved reserves for these four fields totaled 89.2 million barrels of oil equivalent, or approximately 21% of the Company's worldwide proved reserves, including synthetic oil. Two of the fields are currently partially on production and the third is being developed, with expected first production for the latter field in the second half of 2004. Murphy believes the proved reserves are properly classified. Murphy has furnished the information requested by the SEC and is unable to predict the outcome of the SEC's staff review of the industry's practices. This issue is not expected to have a material effect on the Company's financial results. If the issue is not favorably resolved, the Company may be required to revise the manner in which it reports its proved reserves, which could affect its finding costs per barrel and reserve replacement ratios.

Refining and Marketing – The Company's refining and marketing operations lost $11.2 million in 2003 and $39.9 million in 2002. Earnings from this business were a record $153.7 million in 2001, including gains on asset sales. The 2003 loss from refining and marketing operations was lower than the 2002 loss by $28.7 million primarily due to better margins from the gasoline retail business in North America and the refining and marketing business in the United Kingdom. Overall, the Company's U.S. refining margins continued to be squeezed in 2003, primarily due to the high price of crude oil that the Company was not able to completely pass on to wholesale and other refinery customers. In addition to higher average fuel margins in 2003 at North American retail gasoline stations, the Company's profits from merchandise sales at these gasoline stations were also better in 2003.

During 2002, the unfavorable refining and marketing results were generally due to two reasons – extremely weak refining margins throughout most of the year in both the United States and United Kingdom, and a $71 million gain in 2001 on sale of the Company's former Canadian pipeline and trucking operations. Crude oil feedstock prices at the Company's U.S. and U.K. refineries were higher in 2002 than in 2001 and the increase in wholesale and retail sales prices for refined products in 2002 did not match the increased costs of crude oil in the markets served by the Company. Prior to the sale of the Canadian operations, this business generated a profit of $3.8 million in 2001.

Geographically, the North American refining and marketing operations lost $21.2 million in 2003 and $39.2 million in 2002, following a profit of $139.6 million in 2001, which included the $71 million gain on sale of Canadian assets. North American operations include refining activities in the United States and marketing activities in the United States and Canada. It also formerly included pipeline and trucking operations in Canada prior to the sale of this business in 2001. Operations in the U.K. generated a profit of $10 million in 2003, but lost $.7 million in 2002. This business earned $14.1 million in 2001.

Unit margins (sales realizations less costs of crude oil, other feedstocks, refining operating expenses and depreciation and transportation to point of sale) averaged $1.60 per barrel in North America in 2003, $.80 in 2002 and $3.12 in 2001. North American product sales volumes increased 30% to a record 229,876 barrels per day in 2003. Sales volumes through the Company's retail gasoline network at Wal-Mart stores continued to grow steadily throughout 2003. The Company's North American refined product sales volume of 176,427 barrels per day in 2002 was 1% higher than in 2001. Higher sales volumes by the retail gasoline network in 2002 compared to 2001 were mostly offset by lower sales volumes in the wholesale market caused by lower finished products produced by the Company's U.S. refineries.

Unit margins in the United Kingdom averaged $2.86 per barrel in 2003, $1.70 per barrel in 2002 and $3.29 in 2001. Sales of petroleum products were up 2% in 2003 following a 10% increase in 2002. Both years' increases were caused by higher volumes sold in the cargo market.

U.S. refining and marketing operations were experiencing losses during early 2004 due to continued weak unit margins during this period.

Based on sales volumes for 2003 and deducting taxes at marginal rates, each $.42 per barrel ($.01 per gallon) fluctuation in the unit margins would have affected annual refining and marketing profits by $25.6 million. The effect of these unit margin fluctuations on consolidated net income cannot be measured because operating results of the Company's exploration and production segments could be affected differently.

Corporate – The costs of corporate activities, which include interest income, interest expense and corporate overhead not allocated to operating functions, were $13.8 million in 2003, $23.6 million in 2002 and $12.8 million in 2001. Net after-tax corporate costs were $9.8 million lower in 2003 mainly due to a $20.1 million benefit from settlement of previous years' income tax audit issues and lower net interest expense. These cost savings were partially offset by higher general and administrative expenses, including costs related to the Company's retirement and incentive compensation plans. The higher net cost of $10.8 million in 2002 compared to 2001 was due to a combination of more net interest expense associated with higher borrowings and lower interest income earned.

Capital Expenditures

As shown in the selected financial data on page 8 of this Form 10-K report, capital expenditures, including discretionary exploration expenditures, were $979.2 million in 2003 compared to $868.1 million in 2002 and $864.4 million in 2001. These amounts included $123.9 million, $134.8 million and $133.8 million of exploration costs that were expensed. Capital expenditures for exploration and production activities totaled $762.7 million in 2003, 78% of the Company's total capital expenditures for the year. Exploration and production capital expenditures in 2003 included $24.4 million for acquisition of undeveloped leases, $196.7 million for exploration activities, and $541.6 million for development projects. Development expenditures included $185.4 million for development of deepwater discoveries in the Gulf of Mexico; $111.2 million for the West Patricia and Kikeh fields in Malaysia; $28.3 million for the Terra Nova and Hibernia oil fields, offshore Newfoundland; $93.8 million for expansion of synthetic oil operations at the Syncrude project in Canada; and $62.5 million for Western Canada projects. Exploration and production capital expenditures are shown by major operating area on page F-33 of this Form 10-K report.

Refining and marketing capital expenditures totaled $215.4 million in 2003, compared to $234.7 million in 2002 and $175.2 million in 2001. These amounts represented 22%, 27% and 20% of total capital expenditures of the Company in 2003, 2002 and 2001, respectively. Refining capital spending was $130.8 million in 2003, compared to $150.1 million in 2002 and $88.9 million in 2001. The Company completed in 2003 its expansion of the Meraux, Louisiana refinery, which included building a hydrocracker unit to meet future clean fuel specifications and expanding the crude oil processing capacity of the plant to 125,000 barrels per day. Capital expenditures related to this expansion project amounted to $69 million in 2003, $116.2 million in 2002 and $55.1 million in 2001. Marketing expenditures amounted to $84.6 million in 2003 and 2002, and $86.3 million in 2001. The majority of marketing expenditures in each year was related to construction of retail gasoline stations at Wal-Mart sites in 21 states in the U.S. The Company began building gasoline stations at Wal-Mart stores in Canada in 2002. The Company opened 119 total stations in the U.S. and Canada in 2003, 125 in 2002 and 111 in 2001.

Cash Flows

Cash provided by continuing operations was $652.3 million in 2003, $527 million in 2002 and $630.6 million in 2001. The increase in cash provided in 2003 was primarily due to higher crude oil and refined product sales volumes, and higher sales prices for crude oil, natural gas and refined products. Cash provided by operating activities was reduced by expenditures for refinery turnarounds and abandonment of oil and gas properties totaling $66.5 million in 2003, $15.2 million in 2002 and $16.4 million in 2001. Scheduled plant-wide turnarounds occurred at both U.S. refineries in 2003.

Cash proceeds from property sales were $188.6 million in 2003, $68.1 million in 2002 and $173 million in 2001. The 2003 property sales included the disposal of the Ninian and Columba fields in the U.K. and various oil and gas assets in Canada and the Gulf of Mexico. Borrowings under notes payable and other long-term debt, which were primarily used to fund a portion of the Company's development capital expenditures, provided $309.7 million of cash in 2003, $407.6 million in 2002 and $88.2 million in 2001. Additional borrowings were lower in 2003 than in 2002 because of higher operational cash flow and higher proceeds from asset sales in the latter year. Cash proceeds from stock option exercises and employee stock purchase plans amounted to $3.6 million in 2003, $25.1 million in 2002 and $18.9 million in 2001.

Property additions and dry hole costs required $937.8 million of cash in 2003, $834.1 million in 2002 and $810.2 million in 2001. More field development expenditures in the deepwater Gulf of Mexico and at the West Patricia and Kikeh fields in Malaysia mostly accounted for the 2003 increase. Cash outlays for debt repayment during the three years included $76.8 million in 2003, $57.8 million in 2002 and $77.7 million in 2001. Larger debt repayments in 2003 were related to nonrecourse debt associated with the Company's Hibernia field. Certain of the nonrecourse debt was repaid using available free cash flow as required by the nonrecourse debt agreement at Hibernia. Free cash flow increased due to a higher average sales price and higher production levels in 2003. Cash used for dividends to stockholders was $73.5 million in 2003, $70.9 million in 2002 and $67.8 million in 2001. The Company raised its annualized dividend rate from $.75 per share to $.80 per share beginning in the third quarter of 2002.

Financial Condition

Year-end working capital totaled $228.5 million in 2003, $136.3 million in 2002 and $38.6 million in 2001. The current level of working capital does not fully reflect the Company's liquidity position as the carrying values for inventories under last-in first-out accounting were $156 million below fair value at December 31, 2003. Cash and cash equivalents at the end of 2003 totaled $252.4 million compared to $165 million a year ago and $82.7 million at the end of 2001.

Long-term debt increased by $227.5 million during 2003 to $1.09 billion at the end of the year, 35.5% of total capital employed. Long-term debt included $28.9 million of nonrecourse debt incurred in connection with the acquisition and development of the Hibernia oil field. The increase in long-term debt in 2003 was attributable to new borrowings associated with the Company's capital expenditure program, including deepwater Gulf of Mexico development projects, continued expansion of the Syncrude plant, development of fields in Malaysia, and an expansion project at the Company's Meraux, Louisiana refinery that was completed by year-end 2003. Long-term debt totaled $862.8 million at the end of 2002 compared to $520.8 million at December 31, 2001. Stockholders' equity was $1.95 billion at the end of 2003 compared to $1.59 billion a year ago and $1.5 billion at the end of 2001. A summary of transactions in stockholders' equity accounts is presented on page F-5 of this Form 10-K report.

Murphy had commitments of $456.4 million for capital projects in progress at December 31, 2003, including $38.9 million for costs to develop deepwater Gulf of Mexico fields, $84.2 million for continued expansion of synthetic oil operations in Canada, and $117.4 million for future work commitments in Malaysia.

The primary sources of the Company's liquidity are internally generated funds, access to outside financing and working capital. The Company typically relies on internally generated funds to finance the major portion of its capital and other expenditures, but maintains lines of credit with banks and borrows as necessary to meet spending requirements. At December 31, 2003, the Company had access to short-term and long-term revolving credit facilities in the amount of $700 million. Of this amount, $150 million of revolving facilities had been drawn at year-end 2003. The most restrictive covenants under these facilities limit the Company's long-term debt to capital ratio (as defined in the agreements) to 60%. At December 31, 2003, the long-term debt to capital ratio was approximately 36%. The Company also has unused uncommitted credit lines of approximately $94 million at December 31, 2003. In addition, the Company has a shelf registration on file with the U.S. Securities and Exchange Commission that permits the offer and sale of up to $650 million in debt and equity securities. Current financing arrangements are set forth more fully in Note E to the consolidated financial statements. At present, the Company does not anticipate utilizing a significant amount of its long-term borrowing capacity in 2004 as proceeds from the intended sale of Western Canada assets and normal cash flow from operations are expected to essentially cover the Company's capital expenditure program. At March 1, 2004 the Company's long-term debt rating by Standard and Poor's was "A-" and by Moody's was "Baal". The Company's ratio of earnings to fixed charges was 6.8 to 1 in 2003, 3.2 to 1 in 2002 and 11.3 to 1 in 2001.

Environmental

Murphy and other companies in the oil and gas industry are subject to numerous federal, state, local and foreign laws and regulations. The most significant of those laws and the corresponding regulations affecting the Company's operations are:

- The Clean Air Act, as amended
- The Federal Water Pollution Control Act
- Safe Drinking Water Act
- Regulations of the United States Department of the Interior governing offshore oil and gas operations

These acts and their associated regulations set limits on emissions and, in the case of discharges to water, establish water quality limits. They also, in most cases, require permits in association with new or modified operations. Many states also have similar statutes and regulations governing air and water, which in some cases impose additional and more stringent requirements. Murphy is also subject to certain acts and regulations primarily governing remediation of wastes or oil spills. The applicable acts are:

- The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), commonly referred to as Superfund, and comparable state statutes. CERCLA primarily addresses historic contamination and imposes joint and several liability for cleanup of contaminated sites on owners and operators of the sites. As discussed below, Murphy is involved in a limited number of Superfund sites. CERCLA also requires reporting of releases to the environment of substances defined as hazardous.

- The Resource Conservation and Recovery Act of 1976, as amended, and comparable state statutes, govern the management and disposal of wastes, with the most stringent regulations applicable to treatment, storage or disposal of hazardous wastes at the owner's property.

- The Oil Pollution Act of 1990, as amended, under which owners and operators of tankers, owners and operators of onshore facilities and pipelines, and lessees or permittees of an area in which an offshore facility is located are liable for removal and cleanup costs of oil discharges into navigable waters of the United States. Pursuant to the authority of the Clean Air Act (CAA), the Environmental Protection Agency (EPA) has issued several standards applicable to the formulation of motor fuels, which are designed to reduce emissions of certain air pollutants when the fuel enters commerce or is used. Pursuant to state laws corresponding to the CAA, several states have passed similar or more stringent regulations governing the formulation of motor fuels.

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, five terminals, and approximately 82 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.

Under the Company's accounting policies, an environmental liability is recorded when such an obligation is probable and the cost can be reasonably estimated. If there is a range of reasonably estimated costs, the most likely amount will be recorded, or if no amount is most likely, the minimum of the range is used. Recorded liabilities are reviewed quarterly. Actual cash expenditures often occur one or more years after a liability is recognized.

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 U.S. Environmental Protection Agency (EPA) currently considers the Company to be 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. Based on currently available information, the Company has reason to believe that it is a de minimus party as to ultimate responsibility at both Superfund sites. The Company has not recorded a liability for remedial costs on Superfund sites. 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 two sites 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.

Certain environmental expenditures are likely to be recovered by the Company from other sources, primarily environmental funds maintained by certain states. Since no assurance can be given that future recoveries from other sources will occur, the Company has not recorded a benefit for likely recoveries at December 31, 2003.

The Company's refineries also incur costs to handle and dispose of hazardous waste and other chemical substances. The types of waste and substances disposed of generally fall into the following categories: spent catalysts (usually hydrotreating catalysts); spent/used filter media; tank bottoms and API separator sludge; contaminated soils; laboratory and maintenance spent solvents; and various industrial debris. The costs of disposing of these substances are expensed as incurred and amounted to $3.5 million in 2003. In addition to these expenses, Murphy allocates a portion of its capital expenditure program to comply with environmental laws and regulations. Such capital expenditures were approximately $140.9 million in 2003 and are projected to be $65.7 million in 2004.

Other Matters

Impact of inflation – General inflation was moderate during the last three years in most countries where the Company operates; however, the Company's revenues and capital and operating costs are influenced to a larger extent by specific price changes in the oil and gas and allied industries than by changes in general inflation. Crude oil and petroleum product prices generally reflect the balance between supply and demand, with crude oil prices being particularly sensitive to OPEC production levels and/or attitudes of traders concerning supply and demand in the near future. Natural gas prices are affected by supply and demand, which to a significant extent are affected by the weather and by the fact that delivery of gas is generally restricted to specific geographic areas. Because crude oil and natural gas sales prices were strong during 2003 and early 2004, prices for oil field goods and services could be adversely affected in the future. Due to the volatility of oil and natural gas prices, it is not possible to determine what effect these prices will have on the future cost of oil field goods and services.

Accounting changes and recent accounting pronouncements – As described in Note B on page F-9 of this Form 10-K report, Murphy adopted the Financial Accounting Standards Board's (FASB) Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 138, effective January 1, 2001 and SFAS No. 143, Accounting for Asset Retirement Obligations, effective January 1, 2003. Upon adoption of SFAS No. 143, the Company recorded an after-tax charge of $7 million, which was reported as the cumulative effect of a change in accounting principle. Adoption of SFAS Nos. 133/138 resulted in a transition adjustment gain to Accumulated Other Comprehensive Loss (AOCL) of $6.6 million, net of $2.8 million in income taxes, for the cumulative effect on prior years; there was no cumulative effect on earnings.

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. FASB Interpretation No. 46 was revised in December 2003 to provide further guidance about consolidation of variable interest entities. Application of this revised interpretation is effective for year-end 2003 for entities considered to be special-purpose entities as defined, or otherwise beginning in 2004 for other entities subject to the revised interpretation. The application of these 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. In addition, this Statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements. The annual disclosures are included in the notes to these consolidated financial statements.

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 established 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.

The FASB issued SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets in 2001. SFAS No. 141 requires that all business combinations after July 2001 be accounted for using the purchase method of accounting and that certain acquired intangible assets in a business combination be recognized and reported as assets apart from goodwill. SFAS No. 142 requires that amortization of goodwill be replaced with annual tests for impairment and that intangible assets other than goodwill be amortized over their useful lives. The Company adopted SFAS No. 141 upon its issuance and adopted SFAS No. 142 on January 1, 2002. The Company had goodwill of $64.9 million at December 31, 2003. Goodwill has been tested for impairment as required by SFAS No. 142 at year-end 2003. Amortization expense related to goodwill was $3.1 million for the year ended December 31, 2001.

In October 2001, the FASB issued SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, which supercedes SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of, and the accounting and reporting provisions of APB Opinion No. 30, Reporting the Results of Operations–Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual, and Infrequently Occurring Events and Transactions. The Company adopted the provision of SFAS No. 144 effective January 1, 2002. The adoption of SFAS No. 144 had no impact on the Company's financial statements.

The Company adopted Emerging Issues Task Force (EITF) Topic 02-3 in the fourth quarter 2002. This consensus required that gains and losses on all derivative instruments within the scope of SFAS No. 133 be shown net in the income statement if the derivatives are held for trading purposes. Accordingly, Murphy reflected the results of its crude oil trading activities as net revenue in its income statement and previously reported revenues and cost of sales were 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 Sales and Other Operating Revenues and Crude Oil, Natural Gas and Product Purchases by approximately $269 million in 2002 and $600 million in 2001.

In July 2003 the FASB undertook to review whether mineral interests in properties (mineral leases) held by oil and gas companies should be recorded and disclosed as intangible assets under the guidance of SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets. The FASB is considering whether an oil and gas company's investment in mineral leases should be classified as intangible assets. SFAS No. 141 and SFAS No. 142 established new accounting guidelines for both finite lived intangible assets and indefinite lived intangible assets. Under SFAS No. 141 and SFAS No. 142, intangible assets should be separately reported on the Balance Sheet, with accompanying disclosures in the notes to the financial statements. SFAS No. 142 does not change the accounting prescribed in SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, and is silent about whether its disclosure provisions apply to oil and gas companies. The Company does not believe that SFAS No. 141 and SFAS No. 142 change the classification and disclosure of oil and gas mineral leases and it continues to classify these assets as part of Property, Plant and Equipment in the Consolidated Balance Sheet and it does not provide the additional disclosures for these assets. The EITF has added the discussion of oil and gas mineral leases to its agenda, which may result in a change in the recording and disclosure of oil and gas mineral leases. Should the EITF determine that oil and gas mineral leases are intangible assets in accordance with SFAS No. 141 and SFAS No. 142, the Company would reclassify $143 million and $142 million as intangible undeveloped mineral interests at December 31, 2003 and 2002, respectively. In addition, a reclassification of $8 million and $7 million would be made as intangible developed mineral interests at December 31, 2003 and 2002, respectively. Both intangible assets would be presented net of accumulated amortization. Historically, undeveloped mineral leases have been amortized over the life of the lease period, while developed mineral leases have been amortized using the units of production method over the expected life of proved reserves. The amounts included herein are based on our understanding of the issue on the EITF's agenda. If all mineral leases associated with oil and gas properties are deemed to be intangible assets in accordance with SFAS No. 141 and SFAS No. 142 by the EITF:

- These assets would not be included in Property, Plant and Equipment on our Consolidated Balance Sheet
- We do not believe that our net income or cash flows from operations would be materially affected because the amortization of these assets would not be different than the method currently used by the Company
- Disclosures required by SFAS No. 141 and SFAS No. 142 relative to intangible assets would be included in the notes to the financial statements

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

- *Proved oil and natural gas reserves* – Proved reserves are defined by the U.S. Securities and Exchange Commission (SEC) as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although the Company's engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. Estimated reserves are often subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of depreciation rates utilized by the Company. The Company cannot predict the type of reserve revisions that will be required in future periods. (See page 15 regarding the SEC's review of the oil and gas industry's recognition of proved reserves.)

- *Successful efforts accounting* – The Company utilizes the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration wells are expensed and can have a significant effect on net income. Successful exploration drilling costs, all development capital expenditures and asset retirement costs are capitalized and systematically charged to expense using the units of production method based on proved oil and natural gas reserves as estimated by the Company's engineers. Costs of exploration wells in progress at year-end 2003 were not significant.

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

- *Income taxes* – The Company is subject to income and other similar taxes in all areas in which it operates. When recording income tax expense, certain estimates are required because: (a) income tax returns are generally filed months after the close of its annual accounting period; (b) tax returns are subject to audit by taxing authorities and audits can often take years to complete and settle; and (c) future events often impact the timing of when income tax expenses and benefits are recognized by the Company. The Company has deferred tax assets relating to tax operating loss carryforwards and other basis differences in Ecuador and Malaysia. The Company routinely evaluates all deferred tax assets to determine the likelihood of their realization. A valuation allowance has been recognized for certain deferred tax assets related to Ecuador and Malaysia due to management's belief that these assets are not likely to be realized. The Company occasionally is challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in its various income tax returns. Although the Company believes that it has adequate accruals for matters not resolved with various taxing authorities, gains or losses could occur in future years from changes in estimates or resolution of outstanding matters.

- *Legal, environmental and other contingent matters* – A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and other contingent matters. In addition, the Company often must estimate the amount of such losses. In many cases, management's judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. The Company's management closely monitors known and potential legal, environmental and other contingent matters, and makes its best estimate of the amount of losses and when they should be recorded based on information available to the Company.

Contractual obligations and guarantees – The Company is obligated to make future cash payments under borrowing arrangements, operating leases, purchase obligations and other long-term liabilities. Total payments due after 2003 under such contractual obligations are shown below.

		Amount of Obligation			
(Millions of dollars)	Total	2004	2005-2007	2008-2009	After 2009
Long-term debt	$1,157.5	$ 67.2	$486.4	$ 6.4	$597.5
Operating leases	104.5	16.6	44.3	23.4	20.2
Purchase obligations	658.4	388.8	146.5	55.7	67.4
Other long-term liabilities	305.7	20.1	23.5	46.5	215.6
Total	$2,226.1	$492.7	$700.7	$132.0	$900.7

In the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide financial guarantees or letters of credit that may be drawn upon if the Company fails to perform under those contracts. The amount of commitments that expire in future periods is shown below.

		Amount of Commitment			
(Millions of dollars)	Total	2004	2005-2007	2008-2009	After 2009
Financial guarantees	$ 9.0	$ .5	$ –	$ 2.6	$5.9
Letters of credit	36.4	20.7	6.4	9.3	–
Total	$45.4	$21.2	$6.4	$11.9	$5.9

Material off-balance sheet arrangements – The Company occasionally utilizes off-balance sheet arrangements for operational or funding purposes. The most significant of these arrangements at year-end 2003 involve an oil and natural gas processing contract and a hydrogen purchase contract. The processing contract provides crude oil and natural gas processing capacity for oil and natural gas production from the Medusa field in the Gulf of Mexico. Under the contract, the Company pays a specified amount per barrel of oil equivalent for processing its oil and natural gas through the facility. If actual oil and natural gas production processed through the facility through 2009 is less than a specified quantity, the Company must make additional quarterly payments up to an agreed minimum level that varies over time. The Company has committed to purchase hydrogen for the Meraux refinery from a third party through 2019. The contract requires a monthly minimum base facility charge whether or not any hydrogen is purchased. Payments under both these agreements are recorded as operating expenses when paid. Future required minimum annual payments under both of these arrangements are included in the contractual obligation table shown above.

Outlook

Prices for the Company's primary products are often quite volatile. During 2003 and early 2004 crude oil prices remained strong primarily due to uncertainty in Iraq and the Middle East, coupled with an improving global economy and effective price management practices utilized by OPEC. High crude oil prices were a contributing factor to weak earnings and cash flows from the Company's refining and marketing operations. Natural gas prices also were strong in 2003 and early 2004, mainly due to demand for the product often outstripping supply in the short term. Due to the volatility of worldwide crude oil prices and U.S. natural gas prices constant reassessment of spending plans is required.

The Company's capital expenditure budget for 2004 was prepared during the fall of 2003 and provides for capital expenditures of $843 million. Of this amount, $650 million or 77%, is allocated for exploration and production. Geographically, 29% of the exploration and production budget is allocated to the United States, including $84 million for development of deepwater projects in the Gulf of Mexico; another 28% is allocated to Canada, including $32 million for continued development of the Hibernia and Terra Nova fields and $75 million for further expansion of synthetic oil operations; 37% is allocated to exploration and development in Malaysia; and the remaining 6% is planned for other areas, including Ecuador, the United Kingdom and the Republic of Congo. Budgeted refining and marketing capital expenditures for 2004 are $184 million, including $165 million in North America and $19 million in the United Kingdom. Planned spending in North America includes funds to build 160 additional gasoline stations at Wal-Mart sites. Capital and other expenditures are under constant review and planned capital expenditures may be adjusted to reflect differences between budgeted and actual cash flow during 2004.

In late 2003, the Company announced its intent to sell most of its conventional oil and natural gas properties in Western Canada. The properties expected to be sold produce approximately 20,000 barrels of oil equivalent per day. Marketing of the properties to be sold began in February, and the sale is expected to be completed in the second quarter of 2004. The gain or loss on the sale and the operating results of the properties to be sold are expected to be accounted for as discontinued operations beginning in 2004.

The Company currently does not anticipate a significant increase in long-term borrowings between year-ends 2003 and 2004. Although Murphy's 2004 Budget includes a robust amount of capital spending, the Company expects the proceeds of the sale of Western Canada conventional oil and gas properties and normal operating cash flows to essentially cover planned spending. It is possible that long-term debt could exceed the budgeted year-end 2004 levels, especially if the sales proceeds in Western Canada are less than anticipated or if cash flows are adversely affected in the upcoming months by significantly weaker oil and natural gas sales prices and continued weak refining and marketing margins such as those experienced in early 2004.

The Company has made significant oil discoveries in deep waters off Sabah, Malaysia. The Company is currently preparing a plan of development and considering its alternatives for funding the project. Although it is too early to predict the ultimate cost of the development project, it is likely that a significant portion of the Company's share of funding will come from borrowed capital. Significant development costs are currently expected to begin in 2005. First production from the deepwater fields offshore Sabah is estimated to occur in 2007.

Murphy's oil production is expected to grow in 2004. The Medusa and Habanero fields in the deepwater Gulf of Mexico started up November 2003 and the West Patricia field in Malaysia came on line in May 2003. Production from the deepwater Gulf of Mexico fields will ramp up in early 2004. Another deepwater Gulf of Mexico field known as Front Runner is expected to come on production in the second half of 2004. These new fields are expected to more than offset normal production declines and the expected sale of Western Canada properties. Natural gas sales volumes are expected to decline in 2004 compared to 2003 levels. Total production for 2004 is projected to average approximately 130,000 barrels of oil equivalent per day.

Murphy Oil and certain of its subsidiaries maintain defined benefit retirement plans covering most of its full-time employees. During 2003, the Company reduced the expected investment return for assets held in its U.S. retirement plans from 8.0% to 7.5%. Due to a reduction in bond yields during 2003, the Company has also reduced the plans' discount rates from 6.75% in 2003 to 6.25% in 2004. The funded status of the Company's retirement plans was adversely affected over the last two years by changes in assumptions used to calculate plan liabilities. The smoothing effect of current accounting regulations tend to buffer the current year's pension expense from wide swings in liabilities and asset returns. The effect of liability assumption changes will adversely impact the Company's pension expense in 2004. The Company's annual retirement plan expense is estimated to increase by about $2.5 million for 2004 compared to 2003. In 2004, the Company is required to fund payments of approximately $2.5 million into two funded retirement plans and expects to pay $1.1 million for two unfunded plans. The Company could be required to make additional and more significant funding payments to retirement plans in future years.

Forward-Looking Statements

This Form 10-K report, including documents incorporated by reference here, 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 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to market risks associated with interest rates, prices of crude oil, natural gas and petroleum products, and foreign currency exchange rates. As described in Note A to the consolidated financial statements, Murphy makes limited 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 December 31, 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 December 31, 2003, the interest rate to be received by the Company averaged 1.64%. 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 $1.8 million at December 31, 2003.

At December 31, 2003, 40% of the Company's debt had variable interest rates and 2% was denominated in Canadian dollars. Based on debt outstanding at December 31, 2003, a 10% increase in interest rates on variable rate debt would increase the Company's interest expense in

2004 by approximately $3.4 million 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 in 2004 by less than $.1 million for debt denominated in Canadian dollars.

Murphy was a party to natural gas swap agreements at December 31, 2003 for a total notional volume of 9.2 MMBTU that were originally designated as a hedge of 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 December 31, 2003, the estimated fair value of these agreements was recorded as an asset of $22.8 million. A 10% increase in the average NYMEX price of natural gas would have increased this asset by $4.7 million, while a 10% decrease would have reduced the asset by a similar amount. As described in Note J on Page F-21, at December 31, 2003, a portion of these agreements no longer qualified for hedge accounting and a portion of these agreements have been redesignated as a hedge of natural gas to be purchased by the Superior refinery in 2004.

Murphy is subject to foreign currency exchange risk, primarily because of its operations in Canada and the U.K. Fluctuations in foreign currencies affect reported revenues and operating costs, capital expenditures and assets and liabilities denominated in currencies other than the U.S. dollar. On occasion, the Company has used financial currency contracts to manage this risk. At December 31, 2003, the Company had $33 million in Canadian dollar forward contracts that matured within 30 days. The fair value of these contracts was recorded in income at the end of 2003 and did not significantly impact the Company's financial statements.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages F-1 through F-38, which follow page 27 of this Form 10-K report.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

Item 9A. CONTROLS AND PROCEDURES

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 the Company's evaluation as of the end of the period covered by the filing of this Annual Report on Form 10-K, 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 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 were no significant changes in the Company's internal controls over financial reporting that occurred during the fourth quarter of 2003 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Certain information regarding executive officers of the Company is included on page 7 of this Form 10-K report. Other information required by this item is incorporated by reference to the Registrant's definitive Proxy Statement for the Annual Meeting of Stockholders on May 12, 2004 under the caption "Election of Directors."

Murphy Oil has adopted a Code of Ethical Conduct for Executive Management, which can be found under the Corporate Governance and Responsibility tab at www.murphyoilcorp.com. Stockholders may also obtain free of charge a copy of the Code of Ethical Conduct for Executive Management by writing to the Company's Secretary at P.O. Box 7000, El Dorado, AR 71731-7000. Any future amendments to or waivers of the Company's Code of Ethical Conduct for Executive Management will be posted on the Company's internet website.

Item 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 12, 2004 under the captions "Compensation of Directors," "Executive Compensation," "Option Exercises and Fiscal Year-End Values," "Option Grants," "Compensation Committee Report for 2003," "Shareholder Return Performance Presentation" and "Retirement Plans."

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 12, 2004 under the captions "Security Ownership of Certain Beneficial Owners," "Security Ownership of Management," and "Equity Compensation Plan Information."

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 12, 2004 under the caption "Audit Committee Report."

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) 1. Financial Statements – The consolidated financial statements of Murphy Oil Corporation and consolidated subsidiaries are located or begin on the pages of this Form 10-K report as indicated below.

2. Financial Statement Schedules

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

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

Exhibit No.		Incorporated by Reference to
3.1	Certificate of Incorporation of Murphy Oil Corporation as amended, effective May 17, 2001	Exhibit 3.1 of Murphy's Form 10-Q report for the quarterly period ended June 30, 2001
3.2	By-Laws of Murphy Oil Corporation as amended effective June 24, 2003	Exhibit 3.2 of Murphy's Form 10-Q report for the quarterly period ended June 30, 2003
4	Instruments Defining the Rights of Security Holders. Murphy is party to several long-term debt instruments in addition to the one in Exhibit 4.1, none of which authorizes securities exceeding 10% of the total consolidated assets of Murphy and its subsidiaries. Pursuant to Regulation S-K, item 601(b), paragraph 4(iii)(A), Murphy agrees to furnish a copy of each such instrument to the Securities and Exchange Commission upon request.	
4.1	Form of Second Supplemental Indenture between Murphy Oil Corporation and SunTrust Bank, as Trustee	Exhibit 4.1 of Murphy's Form 8-K report filed May 3, 2002 under the Securities Exchange Act of 1934
4.2	Form of Indenture and Form of Supplemental Indenture between Murphy Oil Corporation and SunTrust Bank, as Trustee	Exhibits 4.1 and 4.2 of Murphy's Form 8-K report filed April 29, 1999 under the Securities Exchange Act of 1934
4.3	Rights Agreement dated as of December 6, 1989 between Murphy Oil Corporation and Harris Trust Company of New York, as Rights Agent	Exhibit 4.3 of Murphy's Form 10-K report for the year ended December 31, 1999
4.4	Amendment No. 1 dated as of April 6, 1998 to Rights Agreement dated as of December 6, 1989 between Murphy Oil Corporation and Harris Trust Company of New York, as Rights Agent	Exhibit 3 of Murphy's Form 8-A/A, Amendment No. 1, filed April 14, 1998 under the Securities Exchange Act of 1934
4.5	Amendment No. 2 dated as of April 15, 1999 to Rights Agreement dated as of December 6, 1989 between Murphy Oil Corporation and Harris Trust Company of New York, as Rights Agent	Exhibit 4 of Murphy's Form 8-A/A, Amendment No. 2, filed April 19, 1999 under the Securities Exchange Act of 1934
10.1	1992 Stock Incentive Plan as amended May 14, 1997, December 1, 1999 and May 14, 2003	Exhibit 10.1 of Murphy's Form 10-Q report for the quarterly period ended June 30, 2003
10.2	Employee Stock Purchase Plan as amended May 10, 2000 August 4, 2000 under the Securities Act of 1933	Exhibit 99.01 of Murphy's Form S-8 Registration Statement filed
10.3	Murphy Vehicle Fueling Station Master Ground Lease Agreement	Exhibit 10.3 of Murphy's Form 10-K report for the year ended December 31, 2002
*10.4	Stock Plan for Non-Employee Directors, as approved by shareholders on May 14, 2003	
*12.1	Computation of Ratio of Earnings to Fixed Charges	
*13	2003 Annual Report to Security Holders including Narrative to Graphic and Image Material as an appendix	
*21	Subsidiaries of the Registrant	
*23	Independent Auditors' Consent	

Exhibit No.		Incorporated by Reference to
*31.1	Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
*31.2	Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
32	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	See footnote 1 below.

[1] These certifications will not be deemed to be filed with the Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

(b) Reports on Form 8-K

A report on form 8-K was filed on October 28, 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 nine-months periods that ended on September 30, 2003.

SIGNATURES

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

MURPHY OIL CORPORATION

By CLAIBORNE P. DEMING
Claiborne P. Deming, President

Date: March 12, 2004

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on March 12, 2004 by the following persons on behalf of the registrant and in the capacities indicated.

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

CLAIBORNE P. DEMING
Claiborne P. Deming, President and Chief Executive Officer and Director
(Principal Executive Officer)

FRANK W. BLUE
Frank W. Blue, Director

GEORGE S. DEMBROSKI
George S. Dembroski, Director

H. RODES HART
H. Rodes Hart, Director

ROBERT A. HERMES
Robert A. Hermes, Director

R. MADISON MURPHY
R. Madison Murphy, Director

IVAR B. RAMBERG
Ivar B. Ramberg, Director

DAVID J. H. SMITH
David J. H. Smith, Director

CAROLINE G. THEUS
Caroline G. Theus, Director

STEVEN A. COSSÉ
Steven A. Cossé, Senior Vice President and General Counsel
(Principal Financial Officer)

JOHN W. ECKART
John W. Eckart, Controller
(Principal Accounting Officer)

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REPORT OF MANAGEMENT

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

Management is also responsible for maintaining a system of internal accounting controls designed to provide reasonable, but not absolute, assurance that financial information is objective and reliable by ensuring that all transactions are properly recorded in the Company's accounts and records, written policies and procedures are followed and assets are safeguarded. The system is also supported by careful selection and training of qualified personnel. When establishing and maintaining such a system, judgment is required to weigh relative costs against expected benefits. The Company's audit staff independently and systematically evaluates and formally reports on the adequacy and effectiveness of the internal control system.

Our independent auditors, KPMG LLP, have audited the consolidated financial statements. Their audit was conducted in accordance with auditing standards generally accepted in the United States of America and provides an independent opinion about the fair presentation of the consolidated financial statements. When performing their audit, KPMG LLP considers the Company's internal control structure to the extent they deem necessary to issue their opinion on the financial statements. The Board of Directors appoints the independent auditors; ratification of the appointment is solicited annually from the shareholders.

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

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Stockholders of Murphy Oil Corporation:

We have audited the accompanying consolidated balance sheets of Murphy Oil Corporation and Consolidated Subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of income, comprehensive income, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Murphy Oil Corporation and Consolidated Subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note B to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations, effective January 1, 2002, the Company changed its method of accounting for goodwill and other intangible assets and effective January 1, 2001, the Company changed its method of accounting for derivative instruments and hedging activities.

KPMG LLP

Shreveport, Louisiana
February 18, 2004

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(Thousands of dollars except per share amounts)*	**2003**	2002	2001
Revenues			
Sales and other operating revenues	**$5,275,099**	$3,966,516	$3,743,986
Gain on sale of assets	**61,524**	9,148	105,504
Interest and other income	**8,615**	8,663	16,478
Total revenues	**5,345,238**	3,984,327	3,865,968
Costs and Expenses			
Crude oil, natural gas and product purchases	**3,651,923**	2,676,012	2,370,550
Operating expenses	**626,740**	540,019	479,336
Exploration expenses, including undeveloped lease amortization	**151,132**	159,429	156,919
Selling and general expenses	**126,589**	98,562	97,835
Depreciation, depletion and amortization	**328,496**	300,022	226,621
Amortization of goodwill	**–**	–	3,120
Impairment of properties	**8,314**	31,640	10,478
Accretion on discounted liabilities	**12,366**	–	–
Interest expense	**57,751**	51,504	39,289
Interest capitalized	**(37,240)**	(24,536)	(20,283)
Total costs and expenses	**4,926,071**	3,832,652	3,363,865
Income from continuing operations before income taxes	**419,167**	151,675	502,103
Income tax expense	**117,977**	54,165	173,673
Income from continuing operations	**301,190**	97,510	328,430
Discontinued operations, net of tax (including gain on disposal in 2002 of $10,650)	**–**	13,998	2,473
Income before cumulative effect of change in accounting principle	**301,190**	111,508	330,903
Cumulative effect of change in accounting principle, net of tax (Note B)	**(6,993)**	–	–
Net Income	**$ 294,197**	$ 111,508	$ 330,903
Income per Common Share – Basic			
Income from continuing operations	**$ 3.28**	$ 1.07	$ 3.63
Discontinued operations	**–**	.15	.03
Cumulative effect of change in accounting principle	**(.08)**	–	–
Net Income – Basic	**$ 3.20**	$ 1.22	$ 3.66
Income per Common Share – Diluted			
Income from continuing operations	**$ 3.25**	$ 1.06	$ 3.60
Discontinued operations	**–**	.15	.03
Cumulative effect of change in accounting principle	**(.08)**	–	–
Net Income – Diluted	**$ 3.17**	$ 1.21	$ 3.63
Average Common shares outstanding – basic	**91,814,821**	91,450,836	90,442,944
Average Common shares outstanding – diluted	**92,742,766**	92,134,967	91,181,998

See notes to consolidated financial statements, page F-7.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

December 31 *(Thousands of dollars)*	**2003**	2002
Assets		
Current assets		
Cash and cash equivalents	**$ 252,425**	$ 164,957
Accounts receivable, less allowance for doubtful accounts of $10,735 in 2003 and $9,307 in 2002	**450,201**	408,782
Inventories, at lower of cost or market		
Crude oil and blend stocks	**46,626**	41,961
Finished products	**157,078**	94,158
Materials and supplies	**66,806**	65,225
Prepaid expenses	**44,779**	59,962
Deferred income taxes	**20,940**	19,115
Total current assets	**1,038,855**	854,160
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $3,472,133 in 2003 and $3,361,726 in 2002	**3,530,800**	2,886,599
Goodwill, net	**64,873**	51,037
Deferred charges and other assets	**78,119**	93,979
Total assets	**$4,712,647**	$3,885,775
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long-term debt	**$ 67,224**	$ 57,104
Accounts payable	**471,692**	447,740
Income taxes	**83,493**	61,559
Other taxes payable	**120,258**	97,770
Other accrued liabilities	**67,659**	53,719
Total current liabilities	**810,326**	717,892
Notes payable	**1,061,410**	788,554
Nonrecourse debt of a subsidiary	**28,897**	74,254
Deferred income taxes	**421,700**	327,771
Asset retirement obligations	**252,397**	160,543
Accrued major repair costs	**20,513**	52,980
Deferred credits and other liabilities	**166,521**	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 at December 31, 2003 and 2002, issued 94,613,379 shares	**94,613**	94,613
Capital in excess of par value	**504,809**	504,983
Retained earnings	**1,357,910**	1,137,177
Accumulated other comprehensive income (loss)	**65,246**	(66,790)
Treasury stock	**(71,695)**	(76,430)
Total stockholders' equity	**1,950,883**	1,593,553
Total liabilities and stockholders' equity	**$4,712,647**	$3,885,775

See notes to consolidated financial statements, page F-7.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(Thousands of dollars)*	**2003**	2002	2001
Operating Activities			
Income from continuing operations	**$ 301,190**	$ 97,510	$ 328,430
Adjustments to reconcile income from continuing operations to net cash provided by operating activities			
Depreciation, depletion and amortization	**328,496**	300,022	226,621
Impairment of properties	**8,314**	31,640	10,478
Provisions for major repairs	**28,514**	24,996	21,070
Expenditures for major repairs and asset retirements	**(66,528)**	(15,188)	(16,395)
Dry hole costs	**82,555**	101,201	82,825
Amortization of undeveloped leases	**27,189**	24,634	23,154
Accretion on discounted liabilities	**12,366**	–	–
Amortization of goodwill	**–**	–	3,120
Deferred and noncurrent income tax charges	**4,047**	5,871	80,052
Pretax gains from disposition of assets	**(61,524)**	(9,148)	(105,504)
Net increase in noncash operating working capital	**(14,913)**	(24,213)	(27,951)
Other operating activities – net	**2,572**	(10,356)	4,731
Net cash provided by continuing operations	**652,278**	526,969	630,631
Net cash provided by discontinued operations	**–**	5,875	5,073
Net cash provided by operating activities	**652,278**	532,844	635,704
Investing Activities			
Property additions and dry hole costs	**(937,776)**	(834,056)	(810,152)
Proceeds from sale of property, plant and equipment	**188,620**	68,056	172,972
Other investing activities – net	**1,309**	(2,177)	(1,410)
Investing activities of discontinued operations	**–**	6,731	(3,348)
Net cash required by investing activities	**(747,847)**	(761,446)	(641,938)
Financing Activities			
Additions to notes payable	**309,500**	407,053	87,000
Reductions of notes payable	**(34,912)**	(32,457)	(62,214)
Additions to nonrecourse debt of a subsidiary	**188**	573	1,241
Reductions of nonrecourse debt of a subsidiary	**(41,844)**	(25,354)	(15,499)
Proceeds from exercise of stock options and employee stock purchase plans	**3,598**	25,131	18,864
Cash dividends paid	**(73,464)**	(70,898)	(67,826)
Other financing activities – net	**(1,533)**	(2,778)	(3,050)
Net cash provided (required) by financing activities	**161,533**	301,270	(41,484)
Effect of exchange rate changes on cash and cash equivalents	**21,504**	9,637	(2,331)
Net increase (decrease) in cash and cash equivalents	**87,468**	82,305	(50,049)
Cash and cash equivalents at January 1	**164,957**	82,652	132,701
Cash and cash equivalents at December 31	**$ 252,425**	$ 164,957	$ 82,652

See notes to consolidated financial statements, page F-7.

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

Years Ended December 31 *(Thousands of dollars)*	**2003**	2002	2001
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	**–**	–	–
Common Stock – par $1.00, authorized 200,000,000 shares, issued 94,613,379 shares at December 31, 2003 and 2002 and 48,775,314 shares at beginning and end of 2001			
Balance at beginning of year	**$ 94,613**	$ 48,775	$ 48,775
Two-for-one stock split on December 30, 2002	**–**	45,838	–
Balance at end of year	**94,613**	94,613	48,775
Capital in Excess of Par Value			
Balance at beginning of year	**504,983**	527,126	514,474
Exercise of stock options, including income tax benefits	**729**	20,039	10,440
Restricted stock transactions	**(1,472)**	2,563	1,272
Sale of stock under employee stock purchase plans	**569**	1,093	940
Two-for-one stock split on December 30, 2002	**–**	(45,838)	–
Balance at end of year	**504,809**	504,983	527,126
Retained Earnings			
Balance at beginning of year	**1,137,177**	1,096,567	833,490
Net income for the year	**294,197**	111,508	330,903
Cash dividends – $.80 per share in 2003, $.775 per share in 2002 and $.75 per share in 2001	**(73,464)**	(70,898)	(67,826)
Balance at end of year	**1,357,910**	1,137,177	1,096,567
Accumulated Other Comprehensive Income (Loss)			
Balance at beginning of year	**(66,790)**	(83,309)	(38,266)
Foreign currency translation gains (losses), net of income taxes	**145,573**	30,878	(49,596)
Cash flow hedging gains (losses), net of income taxes	**17,912**	(13,007)	4,553
Minimum pension liability adjustment, net of income taxes	**(31,449)**	(1,352)	–
Balance at end of year	**65,246**	(66,790)	(83,309)
Unamortized Restricted Stock Awards			
Balance at beginning of year	**–**	(968)	(1,410)
Amortization, forfeitures and changes in price of Common Stock	**–**	968	442
Balance at end of year	**–**	–	(968)
Treasury Stock			
Balance at beginning of year	**(76,430)**	(90,028)	(97,503)
Exercise of stock options	**2,261**	12,852	6,833
Sale of stock under employee stock purchase plans	**799**	749	651
Awarded restricted stock, net of forfeitures, and other	**1,675**	(3)	(9)
Balance at end of year – 2,742,781 shares of Common Stock in 2003, 2,923,925 shares in 2002 and 3,444,234 shares in 2001	**(71,695)**	(76,430)	(90,028)
Total Stockholders' Equity	**$1,950,883**	$1,593,553	$1,498,163

See notes to consolidated financial statements, page F-7.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(Thousands of dollars)*	**2003**	2002	2001
Net income	**$294,197**	$111,508	$330,903
Other comprehensive income (loss), net of tax			
Cash flow hedges			
Net derivative gains (losses)	**45,614**	(8,065)	26
Reclassification adjustments	**(27,702)**	(4,942)	(2,115)
Total cash flow hedges	**17,912**	(13,007)	(2,089)
Net gain (loss) from foreign currency translation	**145,573**	30,878	(49,596)
Minimum pension liability adjustment	**(31,449)**	(1,352)	–
Other comprehensive income (loss) before cumulative effect of accounting change	**132,036**	16,519	(51,685)
Cumulative effect of accounting change (Note B)	**–**	–	6,642
Other comprehensive income (loss)	**132,036**	16,519	(45,043)
Comprehensive Income	**$426,233**	$128,027	$285,860

See notes to consolidated financial statements, page F-7.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note A – Significant Accounting Policies

NATURE OF BUSINESS – Murphy Oil Corporation is an international oil and gas company that conducts its business through various operating subsidiaries. The Company produces oil and natural gas in the United States, Canada, the United Kingdom, Malaysia and Ecuador and conducts oil and natural gas exploration activities worldwide. The Company has an interest in a Canadian synthetic oil operation, owns two petroleum refineries in the United States and has an interest in a refinery in the United Kingdom. Murphy markets petroleum products under various brand names and to unbranded wholesale customers in North America and the United Kingdom.

PRINCIPLES OF CONSOLIDATION – The consolidated financial statements include the accounts of Murphy Oil Corporation and all majority-owned subsidiaries. Investments in affiliates in which the Company owns from 20% to 50% are accounted for by the equity method. Other investments are generally carried at cost. All significant intercompany accounts and transactions have been eliminated.

REVENUE RECOGNITION – Revenues from sales of crude oil, natural gas and refined petroleum products are recorded when deliveries have occurred and legal ownership of the commodity transfers to the customer. Title transfers for crude oil, natural gas and bulk refined products generally occur at pipeline custody points or when a tanker lifting has occurred. Refined products sold at retail are recorded when the customer takes delivery at the pump. Revenues from the production of oil and natural gas properties in which Murphy shares an undivided interest with other producers are recognized based on the actual volumes sold by the Company during the period. Oil and gas imbalances occur when the Company's actual sales differ from its entitlement under existing working interests. The Company records a liability for oil and gas imbalances when it has sold more than its working interest of oil and gas production and the estimated remaining reserves make it doubtful that partners can recoup their share of production from the field. At December 31, 2003 and 2002, no liabilities for oil balancing existed and the liabilities for natural gas balancing were immaterial. Excise taxes collected on sales of refined products and remitted to governmental agencies are not included in revenues or in costs and expenses. See Note B regarding adoption of Emerging Issues Task Force (EITF) Issue 02-3 in the fourth quarter 2002.

CASH EQUIVALENTS – Short-term investments, which include government securities and other instruments with government securities as collateral, that have a maturity of three months or less from the date of purchase are classified as cash equivalents.

PROPERTY, PLANT AND EQUIPMENT – The Company uses the successful efforts method to account for exploration and development expenditures. Leasehold acquisition costs are capitalized. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties. Costs of undeveloped leases are generally expensed over the life of the leases. Cost of exploratory drilling is initially capitalized but is subsequently expensed if proved reserves are not found. Other exploratory costs are charged to expense as incurred. Development costs, including unsuccessful development wells, are capitalized.

Oil and gas properties are evaluated by field for potential impairment. Other properties are evaluated for impairment on a specific asset basis or in groups of similar assets as applicable. An impairment is recognized when the estimated undiscounted future net cash flows of an evaluated asset are less than its carrying value.

Depreciation and depletion of producing oil and gas properties are recorded based on units of production. Unit rates are computed for unamortized exploration drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. As more fully described on page F-30 of this Form 10-K report, proved reserves are estimated by the Company's engineers and are subject to future revisions based on availability of additional information. As described in Note B, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 143 on January 1, 2003. Under SFAS No. 143, estimated asset retirement costs are generally recognized when the asset is placed in service, and are amortized over proved reserves using the units of production method. Prior to adoption of SFAS No. 143, estimated dismantlement, abandonment and site restoration costs, net of salvage value, were generally recognized using the units of production method and were included in depreciation expense. Asset retirement costs are estimated by the Company's engineers using existing regulatory requirements and anticipated future inflation rates. Refineries and certain marketing facilities are depreciated primarily using the composite straight-line method with depreciable lives ranging from 16 to 25 years. Gasoline stations and other properties are depreciated over 3 to 20 years by individual unit on the straight-line method.

Gains and losses on asset disposals or retirements are included in income. Actual costs of asset retirements such as dismantling oil and gas production facilities and site restoration are charged against the related liability.

Full plant turnarounds for major processing units are scheduled at 4-1/2 year intervals at the Meraux, Louisiana refinery and 5 year intervals at the Superior, Wisconsin refinery. Turnarounds at the Milford Haven, Wales refinery are scheduled on a 4 year cycle. Turnarounds for coking units at Syncrude Canada Ltd. are scheduled at intervals of 2 to 3 years. Turnaround work associated with various other less significant units at the Company's refineries and Syncrude will occur during the interim period and will vary depending on operating requirements and events.

Murphy accrues in advance for estimated costs of these turnarounds by recording monthly expense provisions. Future major repair costs are estimated by the Company's engineers. Actual costs incurred are charged against the accrued liability. All other maintenance and repairs are expensed. Renewals and betterments are capitalized.

INVENTORIES – Unsold crude oil production is carried in inventory at the lower of cost, generally applied on a first-in first-out (FIFO) basis, or market. Refinery inventories of crude oil and other feedstocks and finished product inventories are valued at the lower of cost, generally applied on a last-in first-out (LIFO) basis, or market. Materials and supplies are valued at the lower of average cost or estimated value.

GOODWILL – The excess of the purchase price over the fair value of net assets acquired associated with the purchase of Beau Canada Exploration Ltd. (Beau Canada) in 2000 was recorded as goodwill. All goodwill recorded at December 31, 2003 and 2002 arose from the purchase of Beau Canada by the Company's wholly owned Canadian subsidiary. Through 2001, goodwill was amortized on a straight-line basis over 15 years, and its recoverability was assessed by determining whether future goodwill amortization could be recovered through undiscounted future net cash flows for western Canadian oil and gas properties. Effective January 1, 2002, in accordance with SFAS No. 142, Goodwill and Other Intangible Assets, goodwill is no longer amortized. SFAS No. 142 requires an annual assessment of recoverability of the carrying value of goodwill. Beginning in 2002, the Company has assessed goodwill recoverability at each year-end by comparing the fair value of net assets for conventional oil and natural gas properties in Canada with the carrying value of these net assets including goodwill. Should a future assessment indicate that goodwill is not fully recoverable, an impairment charge to write down the carrying value of goodwill would be required.

ENVIRONMENTAL LIABILITIES – A provision for environmental obligations is charged to expense when the Company's liability for an environmental assessment and/or cleanup is probable and the cost can be reasonably estimated. Related expenditures are charged against the liability. Environmental remediation liabilities have not been discounted for the time value of future expected payments. Environmental expenditures that have future economic benefit are capitalized.

INCOME TAXES – The Company accounts for income taxes using the asset and liability method. Under this method, income taxes are provided for amounts currently payable and for amounts deferred as tax assets and liabilities based on differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities. Deferred income taxes are measured using the enacted tax rates that are assumed will be in effect when the differences reverse. Petroleum revenue taxes are provided using the estimated effective tax rate over the life of applicable U.K. properties. The Company uses the deferral method to account for Canadian investment tax credits associated with the Hibernia and Terra Nova oil fields.

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

DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES – Effective January 1, 2001, the Company adopted SFAS No. 133, as amended by SFAS No. 138. See also Notes B and J for further information about the Company's derivative instruments. The fair value of a derivative instrument is recognized as an asset or liability in the Company's Consolidated Balance Sheet. Upon entering into a derivative contract, the Company may designate the derivative as either a fair value hedge or a cash flow hedge, or decide that the contract is not a hedge, and thenceforth, mark the contract to fair value through earnings. The Company documents the relationship between the derivative instrument designated as a hedge and the hedged items as well as its objective for risk management and strategy for use of the hedging instrument to manage the risk. Derivative instruments designated as fair value or cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. The Company assesses at inception and on an ongoing basis whether a derivative instrument used as a hedge is highly effective in offsetting changes in the fair value or cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting. Changes in the fair value of a qualifying fair value hedge are recorded in earnings along with the gain or loss on the hedged item. Changes in the fair value of a qualifying cash flow hedge are recorded in other comprehensive income until earnings are affected by the cash flows of the hedged item. When the cash flow of the hedged item is recognized in the Statement of Income, the fair value of the associated cash flow hedge is reclassified from other comprehensive income into earnings. Ineffective portions of a cash flow hedging derivative's change in fair value are recognized currently in earnings. If a derivative instrument no longer qualifies as a cash flow hedge, hedge accounting is discontinued and the gain or loss recorded in other comprehensive income is recognized immediately in earnings.

STOCK OPTIONS – The Company uses 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 to account for its stock options. Under this method, the Company accrues costs of restricted stock and any stock option deemed to be variable in nature over the vesting/performance period and adjusts such costs for changes in the fair market value of Common Stock. No compensation expense is recorded for fixed 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. 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 would be the pro forma amounts shown in the following table.

(Thousands of dollars except per share data)	**2003**	2002	2001
Net income – As reported	**$294,197**	$111,508	$330,903
Restricted stock compensation expense included in income, net of tax	**197**	2,295	1,152
Total stock-based compensation expense using fair value method for all awards, net of tax	**(5,442)**	(9,611)	(7,697)
Net income – Pro forma	**$288,952**	$104,192	$324,358
Net income per share – As reported, basic	**$ 3.20**	$ 1.22	$ 3.66
Pro forma, basic	**3.15**	1.14	3.59
As reported, diluted	**3.17**	1.21	3.63
Pro forma, diluted	**3.11**	1.13	3.56

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

USE OF ESTIMATES – In preparing the financial statements of the Company in conformity with accounting principles generally accepted in the United States of America, management has made a number of estimates and assumptions related to the reporting of assets, liabilities, revenues, and expenses and the disclosure of contingent assets and liabilities. Actual results may differ from the estimates.

Note B – New Accounting Principles and Recent Accounting Pronouncements

On January 1, 2003, the Company adopted 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 obligation (ARO) 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 ARO liability is initially recorded, the Company increases the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is 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 ARO 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 $6,993,000, net of $1,400,000 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 $142,894,000, $58,786,000, and $92,500,000, respectively.

The majority of the ARO recognized by the Company at December 31, 2003 related to the estimated costs to dismantle and abandon its producing oil and gas properties and related equipment. A portion of the transition adjustment and ARO related to its investment in retail gasoline stations. The Company did not record an ARO for its refining and certain of its marketing assets because sufficient information is presently not available to estimate a range of potential settlement dates for the obligation. These assets are consistently being upgraded and are expected to be operational into the foreseeable future. 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.

A reconciliation of the 2003 changes in the ARO liability is shown in the following table.

(Thousands of dollars)	**2003**
December 31, 2002	**$160,543**
Transition adjustment	**92,500**
Accretion expense	**12,366**
Liabilities incurred	**28,210**
Liabilities settled	**(67,234)**
Changes due to translation of foreign currencies	**26,012**
December 31, 2003	**$252,397**

Liabilities settled includes approximately $62,578,000 in noncash reductions of ARO associated with the sale of certain oil and gas producing properties.

The pro forma ARO as of January 1, 2002 and 2001 were $224,466,000 and $212,901,000, respectively. Pro forma net income for the years ended December 31, 2002 and 2001, assuming SFAS No. 143 had been applied retroactively, is shown in the following table.

(Thousands of dollars except per share data)	2002	2001
Net income – As reported	$111,508	$330,903
Pro forma	113,803	329,367
Net income per share – As reported, basic	$ 1.22	$ 3.66
Pro forma, basic	1.24	3.64
As reported, diluted	1.21	3.63
Pro forma, diluted	1.23	3.61

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 SFAS Nos. 145 and 146 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. FASB Interpretation No. 46 was revised in December 2003 to provide further guidance about consolidation of variable interest entities. Application of this revised interpretation is effective for year-end 2003 for entities considered to be special-purpose entities as defined, or otherwise beginning in 2004 for other entities subject to the revised interpretation. The application of these FASB Interpretations did not have a material effect on the Company's financial statements.

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities under SFAS No. 133, Accounting for Derivatives and Hedging Activities. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003, with all provisions applied prospectively. The adoption of SFAS No. 149 did not have a material effect on the Company's financial statements.

In May 2003, the FASB issued SFAS No. 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 No. 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 No. 150 had no impact on the Company's financial statements as the Company had no financial instruments with characteristics of both liabilities and equity.

Effective January 1, 2002, the Company adopted SFAS No. 142, Goodwill and Other Intangible Assets, which no longer permits amortization of goodwill, but rather, requires an annual test for impairment of goodwill, and also requires that intangible assets other than goodwill be amortized over their useful lives. Murphy assesses the recoverability of goodwill by comparing the fair value of net assets for conventional oil and natural gas operations in Canada with the carrying value of these net assets including goodwill. The fair value of the conventional oil and natural gas reporting unit is determined using the expected present value of future cash flows. The carrying amount of goodwill at December 31, 2003 was $64,873,000. The increase in the carrying amount of goodwill during 2003 was primarily due to a change in the exchange rate of Canadian dollars and U.S. dollars. Goodwill is tested for impairment at the end of the Company's fiscal year using the annual oil and gas reserve information. Based on its assessment of the fair value of its Canadian conventional oil and natural gas operations, the Company believes the recorded value of goodwill is not impaired at December 31, 2003. Adjusted net income for the year ended December 31, 2001, excluding goodwill amortization of $3,120,000 ($.03 basic and diluted earnings per share), was $334,023,000. Adjusted basic and diluted earnings per share for the year ended December 31, 2001 were $3.69 and $3.66, respectively.

Effective January 1, 2002, Murphy adopted SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, which supercedes SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of, and the accounting and reporting provisions of APB Opinion No. 30, Reporting the Results of Operations-Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual, and Infrequently Occurring Events and Transactions. This statement retains the basic requirements for recognition and measurement of impairment losses for long-lived assets to be held and used, but for long-lived assets to be disposed of by sale, it broadens the definition of those disposals that should be reported separately as discontinued operations. The adoption of SFAS No. 144 did not have a material effect on the Company's financial statements.

In October 2002, the EITF reached a consensus on certain issues contained in Topic 02-3, Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities. The Company adopted EITF 02-3 in the fourth quarter 2002. This consensus requires that gains and losses on all derivative instruments within the scope of SFAS No. 133 be shown net in the income statement if the derivatives are held for trading purposes. Accordingly, Murphy has reflected the results of its crude oil trading activities net in its income statement and previously reported revenues and cost of sales 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 Sales and Other Operating Revenues and Crude Oil, Natural Gas and Product Purchases by approximately $269,000,000 in 2002 and $600,000,000 in 2001.

Effective January 1, 2001, Murphy adopted SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 138 (SFAS Nos. 133/138). As a result of the change, Murphy records the fair values of its derivative instruments as either assets or liabilities. All such instruments were designated as hedges of forecasted cash flow exposures at adoption. Changes in the fair value of a qualifying cash flow hedging derivative are deferred and recorded as a component of Accumulated Other Comprehensive Income (Loss) (AOCI/AOCL) in the Consolidated Balance Sheet until the forecasted transaction occurs, at which time the derivative's fair value will be recognized in earnings. Ineffective portions of the hedging derivative's change in fair value are immediately recognized in earnings. Adoption of SFAS Nos. 133/138 resulted in a transition adjustment gain to AOCL of $6,642,000, net of $2,845,000 in income taxes, for the cumulative effect on prior years; there was no cumulative effect on earnings. The effect of this accounting change increased AOCI for the year ended December 31, 2003 by $17,912,000, net of $11,549,000 in income taxes and increased income by $5,988,000 for the same period. The accounting change decreased AOCL for the year ended December 31, 2002 by $13,007,000, net of $8,885,000 in income taxes, and decreased income by $1,435,000 for the same period. Excluding the transition adjustment in January 2001, the accounting change decreased AOCL for the year ended December 31, 2001 by $2,089,000, net of $398,000 in income taxes, and decreased net income by $69,000, net of taxes. For the three-year period ended December 31, 2003, losses of $27,702,000, $4,942,000 and $2,115,000, net of $21,309,000, $3,267,000 and $765,000 in taxes, respectively, were reclassified from AOCL to income.

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. In addition, this Statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements.

In July 2003 the FASB undertook to review whether mineral interests in properties (mineral leases) held by oil and gas companies should be recorded and disclosed as intangible assets under the guidance of SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets. The FASB is considering whether an oil and gas company's investment in mineral leases should be classified as intangible assets. SFAS No. 141 and SFAS No. 142 established new accounting guidelines for both finite lived intangible assets and indefinite lived intangible assets. Under SFAS No. 141 and SFAS No. 142, intangible assets should be separately reported on the Balance Sheet, with accompanying disclosures in the notes to the financial statements. SFAS No. 142 does not change the accounting prescribed in SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, and is silent about whether its disclosure provisions apply to oil and gas companies. The Company does not believe that SFAS No. 141 and SFAS No. 142 change the classification and disclosure of oil and gas mineral leases and it continues to classify these assets as part of Property, Plant and Equipment in the Consolidated Balance Sheet and it does not provide the additional disclosures for these assets. The EITF has added the discussion of oil and gas mineral leases to its agenda, which may result in a change in the recording and disclosure of oil and gas mineral leases. Should the EITF determine that oil and gas mineral leases are intangible assets in accordance with SFAS No. 141 and SFAS No. 142, the Company would reclassify $143,251,000 and $142,297,000 as intangible undeveloped mineral interests at December 31, 2003 and 2002, respectively. In addition, a reclassification of $8,290,000 and $6,591,000 would be made as intangible developed mineral interests at December 31, 2003 and 2002, respectively. Both intangible assets would be presented net of accumulated amortization. Historically, undeveloped mineral leases have been amortized over the life of the lease period, while developed mineral leases have been amortized using the units of production method over the expected life of proved reserves. The amounts included herein are based on our understanding of the issue on the EITF's agenda. If all mineral leases associated with oil and gas properties are deemed to be intangible assets in accordance with SFAS No. 141 and SFAS No. 142 by the EITF:

- These assets would not be included in Property, Plant and Equipment on our Consolidated Balance Sheet
- We do not believe that our net income or cash flows from operations would be materially affected because the amortization of these assets would not be different than the method currently used by the Company
- Disclosures required by SFAS No. 141 and SFAS No. 142 relative to intangible assets would be included in the notes to the financial statements.

Note C – Discontinued Operations

In December 2002, the Company sold its interest in Ship Shoal Block 113 in the Gulf of Mexico for an after-tax gain of $10,650,000. The gain, plus normal results of operations for the field prior to the sale, have been reported as Discontinued Operations in the Consolidated Statements of Income for 2002 and 2001. Ship Shoal Block 113 generated revenues, excluding gain on sale, of $15,515,000 in 2002 and $13,410,000 in 2001. Comparable pretax earnings from the field were $5,151,000 in 2002 and $3,805,000 in 2001.

Note D – Property, Plant and Equipment

	December 31, 2003		December 31, 2002	
(Thousands of dollars)	**Cost**	**Net**	Cost	Net
Exploration and production	**$5,294,386**	**$2,538,131***	$4,739,856	$2,055,187*
Refining	**1,104,589**	**555,822**	986,986	451,207
Marketing	**558,046**	**412,550**	476,633	354,412
Corporate and other	**45,912**	**24,297**	44,850	25,793
	$7,002,933	**$3,530,800**	$6,248,325	$2,886,599

*Includes $22,006 in 2003 and $20,721 in 2002 related to administrative assets and support equipment.

In the Consolidated Statements of Income during the three year period ended December 31, 2003, the Company recorded noncash charges of $8,314,000, $31,640,000, and $10,478,000, respectively, for impairment of certain properties. After related income tax benefits, these write-downs reduced net income by $5,404,000 in 2003, $20,567,000 in 2002 and $6,811,000 in 2001. The 2003 charge included $5,314,000 to write-down the cost of a refined product terminal to be closed and certain components of the Meraux refinery that were rendered obsolete upon completion of the refinery upgrade, and $3,000,000 to write-down the cost of a natural gas field in the Gulf of Mexico due to downward revisions in reserves caused by poor well performance. The 2002 charge included $22,487,000 to write-down the remaining cost in Destin Dome Blocks 56 and 57, offshore Florida. In 2002, Murphy reached an agreement with the U.S. government that restricts the Company's ability to seek approval for development of this natural gas discovery until at least 2012. The additional charges in 2002 and 2001 were caused by downward reserve revisions for poor well performance of natural gas fields in the Gulf of Mexico. The carrying value of impaired properties were reduced to the asset's fair value based on projected future discounted net cash flows using the Company's estimate of future commodity prices.

Note E – Financing Arrangements

At December 31, 2003, the Company had two committed credit facilities with a major banking consortium totaling US $700,000,000. The Company and a subsidiary may borrow under a US $150,000,000 revolving credit agreement maturing in December 2006. Additionally, the Company has available a US $550,000,000 three-year revolving credit agreement also maturing in December 2006. U.S. dollar commercial paper totaling an equivalent US $37,000,000 at December 31, 2003 was outstanding and classified as nonrecourse debt. This outstanding debt is supported by a similar amount of credit facilities with major banks based on loan guarantees from the Canadian government. Depending on the credit facility, borrowings bear interest at prime or varying cost of fund options. Facility fees are due at varying rates on the commitments. The Company also had uncommitted lines of credit with banks at December 31, 2003 totaling an equivalent US $362,000,000 for a combination of U.S. dollar and Canadian dollar borrowings. The Company has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of up to US $650,000,000 in debt and equity securities.

Note F – Long-term Debt

December 31 *(Thousands of dollars)*	**2003**	2002
Notes payable		
6.375% notes, due 2012, net of unamortized discount of $962 at December 31, 2003	**$ 349,038**	$348,928
7.05% notes, due 2029, net of unamortized discount of $2,351 at December 31, 2003	**247,649**	247,553
6.23% structured loan, due 2004-2005	**82,854**	117,486
Notes payable to bank, 1.295% to 1.59%, due 2004-2006	**417,500**	108,200
Other, 6% to 8%, due 2004-2021	**1,046**	1,104
Total notes payable	**1,098,087**	823,271
Nonrecourse debt of a subsidiary		
Guaranteed credit facilities with banks		
Commercial paper, 1.175%, supported by credit facility, due 2004	**37,000**	74,997
Loans payable to Canadian government, interest free, payable in Canadian dollars, due 2004-2009	**22,444**	21,644
Total nonrecourse debt of a subsidiary	**59,444**	96,641
Total debt including current maturities	**1,157,531**	919,912
Current maturities	**(67,224)**	(57,104)
Total long-term debt	**$1,090,307**	$862,808

Maturities for the four years after 2004 are: $60,858,000 in 2005, $421,527,000 in 2006, $4,018,000 in 2007 and $6,408,000 in 2008.

Notes payable to bank totaling $267,500,000, that are due in 2004, have been classified as long-term debt since the Company is capable of refinancing the borrowing under an existing long-term credit facility.

With the support of a major bank consortium, the structured loan was borrowed by a Canadian subsidiary in December 2000 to replace temporary financing of the Beau Canada acquisition. The 6.23% fixed-rate loan is reduced in quarterly installments. Payment of interest under the loan has been guaranteed by the Company.

The nonrecourse guaranteed credit facilities were arranged to finance certain expenditures for the Hibernia oil field. Subject to certain conditions and limitations, the Canadian government has unconditionally guaranteed repayment of amounts drawn under the facilities to lenders having qualifying Participation Certificates. Additionally, payment is secured by a debenture that mortgages the Company's share of the Hibernia properties and the production therefrom. Recourse of the lenders is limited to the Canadian government's guarantee; the government's recourse to the Company is limited, subject to certain covenants, to Murphy's interest in the assets and operations of Hibernia. The amount guaranteed is reduced quarterly by the greater of 30% of Murphy's after-tax free cash flow from Hibernia or 1/32 of the original total guarantee. A guarantee fee of .5% is payable annually in arrears to the Canadian government. Based on current oil prices, the Company expects to repay nonrecourse debt covered by guaranteed credit facilities during 2005.

The interest-free loans from the Canadian government were also used to finance expenditures for the Hibernia field. The outstanding balance is primarily to be repaid in equal annual installments through 2008.

Note G – Income Taxes

The components of income from continuing operations before income taxes for each of the three years ended December 31, 2003 and income tax expense (benefit) attributable thereto were as follows.

(Thousands of dollars)	**2003**	2002	2001
Income (loss) from continuing operations before income taxes			
United States	**$ (50,296)**	$(128,523)	$157,251
Foreign	**469,463**	280,198	344,852
	$419,167	$ 151,675	$502,103
Income tax expense (benefit) from continuing operations			
Federal – Current[1]	**$ (5,321)**	$ (41,531)	$ 28,821
Deferred	**(11,911)**	(1,349)	33,167
Noncurrent	**(18,217)**	(6,824)	(4,136)
	(35,449)	(49,704)	57,852
State – Current	**84**	(529)	4,710
Foreign – Current	**119,167**	90,304	60,090
Deferred[2]	**24,525**	16,982	50,916
Noncurrent	**9,650**	(2,888)	105
	153,342	104,398	111,111
Total	**$117,977**	$ 54,165	$173,673

[1] Net of benefit of $10,939 in 2002 for alternative minimum tax credits.

[2] Includes a benefit of $11,800 in 2003 for enacted reductions in federal and provincial tax rates in Canada, a charge of $1,997 in 2002 for an enacted increase in the U.K. tax rate for North Sea oil production and a benefit of $5,540 in 2001 for an enacted reduction in a provincial tax rate in Canada.

Income tax benefits attributable to employee stock option transactions of $467,000 in 2003, $3,833,000 in 2002 and $1,685,000 in 2001 were included in Capital in Excess of Par Value in the Consolidated Balance Sheets. Income tax (benefits) charges of $(11,549,000) in 2003, $(8,885,000) in 2002 and $2,447,000 in 2001 relating to derivatives were included in AOCL.

Total income tax expense in 2003, 2002 and 2001, including taxes associated with discontinued operations and the cumulative effect of accounting change, was $116,577,000, $61,702,000, and $175,005,000, respectively.

Noncurrent taxes, classified in the Consolidated Balance Sheets as a component of Deferred Credits and Other Liabilities, relate primarily to matters not resolved with various taxing authorities.

The following table reconciles income taxes based on the U.S. statutory tax rate to the Company's income tax expense from continuing operations and before cumulative effect of accounting change.

(Thousands of dollars)	**2003**	2002	2001
Income tax expense based on the U.S. statutory tax rate	**$146,708**	$53,086	$175,736
Foreign income subject to foreign taxes at a rate different than the U.S. statutory rate	**18,009**	11,240	2,498
State income taxes	**54**	(344)	3,062
Settlement of U.S. taxes	**(20,146)**	(8,134)	(1,446)
Settlement of foreign taxes	**–**	–	(1,915)
Changes in foreign tax rates	**(11,800)**	1,997	(5,540)
Recognition of tax benefit related to prior year expenses in Malaysia	**(11,410)**	–	–
Other, net	**(3,438)**	(3,680)	1,278
Total	**$117,977**	$54,165	$173,673

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2003 and 2002 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	2003	2002
Deferred tax assets		
Property and leasehold costs	**$ 107,690**	$ 101,734
Liabilities for dismantlements and major repairs	**96,179**	83,072
Postretirement and other employee benefits	**49,785**	29,595
Federal alternative minimum tax credit carryforward	**15,477**	10,939
Federal operating loss carryforward	**48,795**	–
Foreign tax operating losses	**5,236**	20,989
Other deferred tax assets	**29,388**	29,413
Total gross deferred tax assets	**352,550**	275,742
Less valuation allowance	**(68,050)**	(89,574)
Net deferred tax assets	**284,500**	186,168
Deferred tax liabilities		
Property, plant and equipment	**(75,940)**	(52,993)
Accumulated depreciation, depletion and amortization	**(467,105)**	(394,726)
Other deferred tax liabilities	**(135,211)**	(47,105)
Total gross deferred tax liabilities	**(678,256)**	(494,824)
Net deferred tax liabilities*	**$(393,756)**	$(308,656)

* Includes deferred tax asset in Malaysia of $7,004 reported in Deferred Charges and Other Assets in the Consolidated Balance Sheet.

During 2003, the Company generated a net operating loss carryforward for Federal income tax purposes of $139,414,000 that is available to offset future Federal taxable income through 2023. In addition, the Company has alternative minimum tax credit carryforwards of $15,477,000, which are available to reduce future Federal regular income taxes over an indefinite period. Also, at December 31, 2003, the Company had tax loss carryforwards of $9,661,000 associated with its operations in Ecuador. The losses, available only to Ecuador operations, have a carryforward period of no more than five years, with certain losses limited to 25% of each year's taxable income. These losses expire in 2004 to 2007.

In management's judgment, the net deferred tax assets in the preceding table will more likely than not be realized as reductions of future taxable income or by utilizing available tax planning strategies. The valuation allowance for deferred tax assets relates primarily to tax assets arising in foreign tax jurisdictions, and in the judgment of management, these tax assets are not likely to be realized. During 2003, the Company recorded an $11,410,000 deferred tax credit to recognize anticipated future tax benefits on previously incurred expenses related to Blocks SK 309 and 311 in Malaysia. This benefit has been reported as a change in the beginning of the year valuation allowance. Excluding the change in the beginning of the year valuation allowance in 2003, the valuation allowance decreased $10,114,000 in 2003 and increased $21,829,000 in 2002, with these changes primarily offsetting the change in certain deferred tax assets. Any subsequent reductions of the valuation allowance will be reported as reductions of tax expense assuming no offsetting change in the deferred tax asset.

Subsidiaries included in the Company's U.S. consolidated tax return record income tax expense as though they filed separate tax returns. The parent records adjustments to income tax expense for the effects of consolidation. Income taxes are accrued for retained earnings of certain international subsidiaries and corporate joint ventures intended to be remitted. Income taxes are not accrued for unremitted earnings of international operations that are indefinitely reinvested.

Undistributed earnings of certain international consolidated subsidiaries and affiliates for which no deferred income tax provision has been made for possible future remittances totaled approximately $72,113,000 at December 31, 2003. Substantially all of this amount represents earnings reinvested as part of the Company's ongoing business. It is not practicable to estimate the amount of taxes that might be payable on the eventual remittance of such earnings.

Tax returns are subject to audit by various taxing authorities. In 2003, 2002 and 2001, the Company recorded benefits to income of $20,146,000, $14,737,000 and $3,361,000, respectively, from settlements of U.S. and foreign tax issues primarily related to prior years. Although the Company believes that adequate accruals have been made for unsettled issues, additional gains or losses could occur in future years from resolution of outstanding matters.

Note H – Incentive Plans

The Company's 1992 Stock Incentive Plan (1992 Plan) authorized the Executive Compensation Committee (the Committee) to make annual grants of the Company's Common Stock to executives and other key employees as follows: (1) stock options (nonqualified or incentive), (2) stock appreciation rights (SAR), and/or (3) restricted stock. Annual grants may not exceed 1% of shares outstanding at the end of the preceding year; allowed shares not granted may be granted in future years. In addition, shareholders approved the Stock Plan for Non-Employee Directors (2003 Plan) in 2003. This plan permits the issuance of restricted stock, stock options or a combination thereof to the Company's Directors. The Company uses APB Opinion No. 25 to account for stock-based compensation, accruing costs of restricted stock and any stock options deemed to be variable in nature over the vesting/performance periods and adjusting costs for changes in fair market value of Common Stock. Compensation cost charged against income for stock-based plans was $303,000 in 2003, $5,288,000 in 2002, and $1,892,000 in 2001. Outstanding awards were not significantly modified in the last three years.

STOCK OPTIONS – The Committee fixes the option price of each option granted at no less than fair market value (FMV) on the date of the grant and fixes the option term at no more than 10 years from such date. Each option granted to date under the Plan has had a term of 10 years, has been nonqualified, and has had an option price equal to or higher than FMV at date of grant. Under the 1992 Plan, one-half of each grant may be exercised after two years and the remainder after three years. Under the 2003 Plan, one-third of each grant may be exercised after each of the first three years.

Changes in options outstanding, including shares issued under a prior plan, were as follows.

	Number of Shares	Average Exercise Price
Outstanding at December 31, 2000	2,905,140	$24.73
Granted at FMV	1,036,000	30.83
Exercised	(522,400)	23.64
Outstanding at December 31, 2001	3,418,740	26.74
Granted at FMV	945,000	38.85
Exercised	(983,400)	23.44
Forfeited	(83,500)	31.20
Outstanding at December 31, 2002	3,296,840	31.08
Granted at FMV	845,500	43.09
Exercised	(86,500)	26.02
Forfeited	(21,280)	35.30
Outstanding at December 31, 2003	**4,034,560**	**33.59**
Exercisable at December 31, 2001	1,270,240	$24.57
Exercisable at December 31, 2002	988,340	25.01
Exercisable at December 31, 2003	**1,777,060**	**27.32**

Additional information about stock options outstanding at December 31, 2003 is shown below.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices per Option	No. of Options	Avg. Life in Years	Avg. Price	No. of Options	Avg. Price
$17.84 to $21.12	244,060	4.8	$18.05	244,060	$18.05
$24.88 to $28.48	947,000	5.3	27.45	947,000	27.45
$30.23 to $32.74	1,076,000	6.7	30.90	586,000	30.96
$38.85 to $47.16	1,767,500	8.6	40.67	–	–
	4,034,560	7.1	$33.59	1,777,060	$27.32

The pro forma net income calculations in Note A reflect the following fair values of stock options granted in 2003, 2002 and 2001; fair values of options have been estimated using the Black-Scholes pricing model and the weighted-average assumptions as shown.

	2003	2002	2001
Fair value per option at grant date	**$10.32**	$9.59	$7.20
Assumptions			
Dividend yield	**2.12%**	2.56%	2.84%
Expected volatility	**28.77%**	26.80%	26.34%
Risk-free interest rate	**3.01%**	4.89%	4.93%
Expected life	**5 yrs.**	5 yrs.	5 yrs.

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

RESTRICTED STOCK – Shares of restricted stock were granted under the Plan in certain years. Each grant will vest if the Company achieves specific financial objectives at the end of a five-year performance period. Additional shares may be awarded if objectives are exceeded, but some or all shares may be forfeited if objectives are not met. During the performance period, a grantee receives dividends and may vote these shares, but shares are subject to transfer restrictions and are all or partially forfeited if a grantee terminates. The Company may reimburse a grantee up to 50% of the award value for personal income tax liability on stock awarded. In 2002, eligible shares granted in 1998 were awarded to the grantees, and additional shares were awarded in 2003 based on financial objectives achieved. Changes in restricted stock outstanding were as follows.

(Number of shares)	**2003**	2002	2001
Balance at beginning of year	–	115,166	116,666
Granted	**64,084**	–	–
Awarded	**(64,084)**	(115,166)	–
Forfeited	–	–	(1,500)
Balance at end of year	–	–	115,166

CASH AWARDS – The Committee also administers the Company's incentive compensation plans, which provide for annual or periodic cash awards to officers, directors and key employees if the Company achieves specific financial objectives. Compensation expense of $14,931,000, $3,911,000 and $11,816,000 was recorded in 2003, 2002 and 2001, respectively, for these plans.

EMPLOYEE STOCK PURCHASE PLAN (ESPP) – The Company has an ESPP under which 300,000 shares of the Company's Common Stock could be purchased by eligible U.S. and Canadian employees. Each quarter, an eligible employee may elect to withhold up to 10% of his or her salary to purchase shares of the Company's stock at a price equal to 90% of the fair value of the stock as of the first day of the quarter. The ESPP will terminate on the earlier of the date that employees have purchased all 300,000 shares or June 30, 2007. Employee stock purchases under the ESPP were 30,114 shares at an average price of $44.81 per share in 2003, 24,828 shares at $38.94 in 2002 and 27,350 shares at $25.54 in 2001. At December 31, 2003, 111,795 shares remained available for sale under the ESPP. Compensation costs related to the ESPP were immaterial.

Note I – Employee and Retiree Benefit Plans

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

The tables that follow provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets for the years ended December 31, 2003 and 2002 and a statement of the funded status as of December 31, 2003 and 2002.

	Pension Benefits		Postretirement Benefits	
(Thousands of dollars)	**2003**	2002	**2003**	2002
Change in benefit obligation				
Obligation at January 1	**$296,638**	$261,182	**$ 53,668**	$ 43,335
Service cost	**7,347**	6,721	**1,236**	1,287
Interest cost	**18,753**	18,098	**3,687**	3,280
Plan amendments	**548**	227	**(4,184)**	–
Participant contributions	**63**	69	**689**	539
Actuarial loss	**13,846**	21,160	**14,476**	10,306
Curtailments	**(568)**	–	**–**	–
Exchange rate changes	**8,081**	4,274	**–**	–
Benefits paid	**(14,131)**	(15,093)	**(3,798)**	(5,079)
Obligation at December 31	**330,577**	296,638	**65,774**	53,668
Change in plan assets				
Fair value of plan assets at January 1	**234,432**	256,872	**–**	–
Actual return on plan assets	**30,833**	(12,247)	**–**	–
Employer contributions	**2,584**	1,626	**3,109**	4,540
Participant contributions	**63**	69	**689**	539
Settlements	**(436)**	(375)	**–**	–
Exchange rate changes	**7,837**	3,580	**–**	–
Benefits paid	**(14,131)**	(15,093)	**(3,798)**	(5,079)
Fair value of plan assets at December 31	**261,182**	234,432	**–**	–
Reconciliation of funded status				
Funded status at December 31	**(69,395)**	(62,206)	**(65,774)**	(53,668)
Unrecognized actuarial loss	**82,250**	87,259	**33,321**	20,178
Unrecognized transition asset	**(5,596)**	(6,649)	**–**	–
Unrecognized prior service cost	**6,151**	6,559	**(4,090)**	–
Net plan asset (liability) recognized	**$ 13,410**	$ 24,963	**$(36,543)**	$(33,490)
Amounts recognized in the Consolidated Balance Sheets at December 31				
Prepaid benefit asset	**$ 4,460**	$ 47,070	**$ –**	$ –
Accrued benefit liability	**(44,819)**	(26,660)	**(36,543)**	(33,490)
Intangible asset	**4,122**	2,472	**–**	–
Accumulated other comprehensive loss*	**49,647**	2,081	**–**	–
Net plan asset (liability) recognized	**$ 13,410**	$ 24,963	**$(36,543)**	$(33,490)

*Before reduction for associated deferred taxes of $16,846 at December 31, 2003 and $729 at December 31, 2002.

At December 31, 2003, a minimum pension liability adjustment was required for certain of the Company's plans. For these plans, accumulated benefit obligations exceeded the fair value of plan assets by $34,129,000. After reductions for amounts charged to intangible assets, net of associated deferred income taxes, charges to accumulated other comprehensive loss of $31,449,000 and $1,352,000 were recorded in 2003 and 2002, respectively.

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

	Projected Benefit Obligations		Accumulated Benefit Obligations		Fair Value of Plan Assets	
(Thousands of dollars)	**2003**	2002	**2003**	2002	**2003**	2002
Funded qualified plans where PBO exceeds fair value of plan assets	**$291,473**	$262,349	**$255,873**	$227,360	**$232,535**	$217,891
Unfunded nonqualified and directors' plans where PBO exceeds fair value of plan assets	**24,391**	23,882	**18,493**	14,582	**–**	–
Unfunded postretirement plans	**65,774**	53,668	**36,543**	33,490	**–**	–

The table that follows provides the components of net periodic benefit expense (credit) for each of the three years ended December 31, 2003.

	Pension Benefits			Postretirement Benefits		
(Thousands of dollars)	**2003**	2002	2001	**2003**	2002	2001
Service cost	**$ 7,347**	$6,721	$ 5,757	**$1,236**	$1,287	$ 935
Interest cost	**18,753**	18,097	17,370	**3,687**	3,280	3,009
Expected return on plan assets	**(17,275)**	(19,791)	(24,123)	**–**	–	–
Amortization of prior service cost	**764**	778	782	**(95)**	–	–
Amortization of transitional asset	**(2,052)**	(2,559)	(2,552)	**–**	–	–
Recognized actuarial (gain) loss	**3,664**	1,242	(181)	**1,334**	633	400
	11,201	4,488	(2,947)	**6,162**	5,200	4,344
Curtailment expense	**338**	–	–	**–**	–	–
Settlement gain	**–**	–	(901)	**–**	–	–
Net periodic benefit expense (credit)	**$11,539**	$4,488	$(3,848)	**$6,162**	$5,200	$4,344

Curtailment expense in 2003 recorded unrecognized prior service costs related to the freezing of benefits under the Directors' retirement plan. The settlement gain in 2001 related to employee reductions from the sale of Canadian pipeline and trucking assets.

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

	Pension Benefits		Postretirement Benefits	
(Thousands of dollars)	**2003**	2002	**2003**	2002
Benefit obligation at December 31	**$72,067**	$54,731	**$ –**	$ –
Fair value of plan assets at December 31	**67,396**	48,428	**–**	–
Net plan liability recognized	**(4,181)**	(1,464)	**–**	–
Net periodic benefit expense	**1,431**	1,077	**–**	–

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2003 and 2002 and net periodic benefit expense for the years 2003 and 2002.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits		Postretirement Benefits		Pension Benefits		Postretirement Benefits	
	December 31,		December 31,		Year		Year	
	2003	2002	**2003**	2002	**2003**	2002	**2003**	2002
Discount rate	**6.11%**	6.56%	**6.25%**	6.75%	**6.53%**	6.97%	**6.75%**	7.25%
Expected return on plan assets	**7.46%**	7.81%	**–**	–	**7.46%**	7.81%	**–**	–
Rate of compensation increase	**4.04%**	4.52%	**–**	–	**4.04%**	4.52%	**–**	–

Discount rates are adjusted as necessary, generally based on changes in AA-rated corporate bond rates. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Expected compensation increases are based on historical averages for the Company.

The weighted average asset allocation for the Company's domestic benefit plans at the annual measurement dates of September 30, 2003 and 2002 are presented in the following table.

	September 30,	
	2003	2002
Equity securities	**53.5%**	45.5%
Debt securities	**42.8**	50.7
Cash	**3.7**	3.8
	100.0%	100.0%

The Company has directed the asset investment advisors of its domestic benefit plans to maintain a portfolio nearly balanced between equity and debt securities. The investment advisors may vary the asset mix within the range of 40%-60% for both equity and debt securities. The Company believes that a balanced portfolio of equity and debt securities represents the best long-term mix for future return on domestic plans' assets. Investment advisors are not permitted to invest domestic benefit plan assets in Murphy Oil's common stock.

The Company's expected return on domestic plan assets was 7.5% in 2003 and the return was determined based on an assessment of actual long-term historical returns and expected future returns for a balanced portfolio similar to that maintained by the plans. The 7.5% expected return was based on an expected average future equity asset return of 9.0% and a return on high-quality corporate bonds of 6.0%, and is net of average expected investment expenses of .25%. Over the last 10 years, the return on domestic plans assets has averaged 9.1%.

The Company currently expects to make contributions of $3,573,000 to its domestic defined benefit pension plans and $4,550,000 to its postretirement benefits plan during 2004. The actual 2004 pension contributions may be significantly different as the U.S. Congress was considering pension funding reform measures in early 2004.

For purposes of measuring postretirement benefit obligations at December 31, 2003, the future annual rates of increase in the cost of health care were assumed to be 7.0% for 2004 decreasing 0.5% per year to an ultimate rate of 5.0% in 2008 and thereafter.

Assumed health care cost trend rates have a significant effect on the expense and obligation reported for the postretirement benefit plan. A 1% change in assumed health care cost trend rates would have the following effects.

(Thousands of dollars)	1% Increase	1% Decrease
Effect on total service and interest cost components of net periodic postretirement benefit expense for the year ended December 31, 2003	$ 308	$ (290)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 2003	3,074	(2,969)

On December 8, 2003, the President signed the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). Among other provisions, the Act will provide prescription drug coverage under Medicare beginning in 2006. Generally, companies that provide qualifying prescription drug coverage that is deemed actuarially equivalent to medicare coverage for retirees aged 65 and above will be eligible to receive a federal subsidy equal to 28% of drug costs between $250 and $5,000 per annum for each covered individual that does not elect to receive coverage under the new prescription drug Medicare Part D. The Company currently provides prescription drug coverage to qualifying retirees under its retiree medical plan. Because the Company's plan measurement date of September 30 was prior to the enactment of the Act, the Company is not eligible to recognize a benefit associated with the anticipated cost savings related to the federal subsidy until its 2004 fiscal year. The Company must elect in the first quarter of 2004 whether it will begin to recognize the estimated benefits of the Act in 2004. The Financial Accounting Standards Board has not issued final guidance on accounting for the federal subsidy. Therefore, if the Company elects to record estimated benefits beginning in the first quarter of 2004, these benefits could be changed when final authoritative accounting guidance is issued in the future.

THRIFT PLANS – Most full-time employees of the Company may participate in thrift or savings plans by allotting up to a specified percentage of their base pay. The Company matches contributions at a stated percentage of each employee's allotment based on years of participation in the plans. A U.K. savings plan allows eligible employees to allot a portion of their base pay to purchase Company Common Stock at market value. Such employee allotments are matched by the Company. Common Stock issued from the Company's treasury under this U.K. savings plan was 432 shares in 2003, 12,417 shares in 2002 and 16,136 shares in 2001. Amounts charged to expense for these U.S. and U.K. plans were $5,377,000 in 2003, $4,159,000 in 2002 and $4,061,000 in 2001.

Note J – Financial Instruments and Risk Management

DERIVATIVE INSTRUMENTS – Murphy utilizes derivative instruments on a limited basis 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 $50,000,000 at December 31, 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 1.64% at December 31, 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 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 years ended December 31, 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 and Superior, Wisconsin refineries, 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 financial contracts known as natural gas swaps 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, Natural Gas and Product Purchases in the income statements in the periods in which the hedged natural gas fuel purchases affect earnings. During 2003, the Company determined that natural gas swap contract notional volumes exceeded forecasted 2004 natural gas purchases at its Meraux, Louisiana refinery while the ROSE unit is out of service. Accordingly, natural gas swap contracts with a notional volume of 3.4 MMBTU no longer qualified as a cash flow hedge. Therefore, 1.3 MMBTU of these contracts were redesignated as a cash flow hedge of natural gas the Company will purchase at its Superior refinery during 2004, and the remaining 2.1 MMBTU will not qualify as a hedge and will be marked to fair value through earnings during 2004. Gains of $6.7 million were recognized in earnings in 2003 as a result of the contracts no longer qualifying as a cash flow hedge. The natural gas swap contracts designated as hedges of natural gas the Company will purchase in 2005 through 2006 at the Meraux refinery still qualify as cash flow hedges. For the three years ended December 31, 2003, 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. During 2003 Murphy hedged the cash flow risk associated with the sales price for a portion of the natural gas it produced in the United States and Canada by entering into natural gas swap and collar contracts. The swaps covered a combined notional volume averaging 24,200 MMBTU equivalents per day and required 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 were for a combined notional volume averaging 26,700 MMBTU equivalents per day and provided 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 natural gas price risk pertaining to a portion of gas sales from properties Murphy acquired from Beau Canada in 2000 was limited by natural gas swap agreements that expired in October 2001 that were obtained in the acquisition. These agreements hedged fluctuations in cash flows resulting from such risk. Certain swaps required Murphy to pay a floating price and receive a fixed price and were partially offset by swaps on a lesser volume that required Murphy to pay a fixed price and receive a floating price. The fair value of these swaps was recorded as a net liability upon the acquisition of Beau Canada and was adjusted on January 1, 2001 upon transition to SFAS 133. Net payments by the Company were recorded as a reduction of the associated liability, with any differences recorded as an adjustment of natural gas revenue.

  The fair values of the effective portions of the natural gas swaps and collars and changes thereto were deferred in AOCI and were subsequently reclassified into Sales and Other Operating Revenue in the income statement in the periods in which the hedged natural gas sales affected earnings. For the three-year period ended December 31, 2003, Murphy's earnings were not significantly affected by cash flow hedging ineffectiveness. During 2003, the Company paid $13,107,000 for settlement of natural gas swap and collar agreements. During 2002, the Company received approximately $6,900,000 for settlement of natural gas swap and collar agreements in Canada that were entered into and matured during the year.

- *Crude Oil Sales Price Risks* – The sales price of crude oil produced by the Company is subject to commodity price risk. Murphy hedged the cash flow risk associated with the sales price for the crude oil it produced in the United States and a portion of the oil produced in Canada during 2003 by entering into crude oil swap contracts. The swaps covered a notional volume of 22,000 barrels per day of light oil and required 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 were heavy oil swaps with a notional volume of 10,000 barrels per day that required Murphy to pay the arithmetic average of the posted price at terminals at Kerrobert and Hardisty, 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 were deferred in AOCI and subsequently reclassified into Sales and Other Operating Revenues in the income statement in the periods in which the hedged crude oil sales affected earnings. During 2003 and 2002, earnings were increased (decreased) by $1,507,000 and ($1,371,000), respectively, relating to cash flow hedging ineffectiveness. During 2003 the Company paid approximately $66,950,000 for settlement of maturing crude oil sales swaps.

- *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 crude oil purchases in 2001 and 2002. 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 $7,735,000. The fair values of these settlement gains were recorded in AOCL as part of the transition adjustment at January 1, 2001 and were recognized as a reduction of costs of crude oil purchases in the period the forecasted transactions occurred. Pretax gains of $5,778,000 in 2002 and $1,957,000 in 2001 were reclassified from AOCL into earnings.

During 2004, the Company expects to reclassify approximately $9,478,000 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.

FAIR VALUE – The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2003 and 2002. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties. The table excludes cash and cash equivalents, trade accounts receivable, investments and noncurrent receivables, trade accounts payable and accrued expenses, all of which had fair values approximating carrying amounts. The fair value of current and long-term debt is estimated based on current rates offered the Company for debt of the same maturities. The Company has off-balance sheet exposures relating to certain financial guarantees and letters of credit. The fair value of these, which represents fees associated with obtaining the instruments, was nominal.

	2003		2002	
(Thousands of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial assets (liabilities):				
Interest rate swaps	**$ (1,772)**	**$ (1,772)**	$ (3,829)	$ (3,829)
Natural gas fuel swaps	**22,750**	**22,750**	12,398	12,398
Natural gas sales swaps and collars	–	–	(6,405)	(6,405)
Crude oil sales swaps	–	–	(19,871)	(19,871)
Current and long-term debt	**(1,157,531)**	**(1,279,040)**	(919,912)	(923,350)

The carrying amounts of interest rate swaps, crude oil swaps and natural gas swaps and collars in the preceding table are included in the Consolidated Balance Sheets in Deferred Charges and Other Assets or Other Accrued Liabilities. Current and long-term debt are included under Current Maturities of Long-Term Debt, Notes Payable and Nonrecourse Debt of a Subsidiary.

CREDIT RISKS – The Company's primary credit risks are associated with trade accounts receivable, cash equivalents and derivative instruments. Trade receivables arise mainly from sales of crude oil, natural gas and petroleum products to a large number of customers in the United States, Canada and the United Kingdom. The credit history and financial condition of potential customers are reviewed before credit is extended, security is obtained when deemed appropriate based on a potential customer's financial condition, and routine follow-up evaluations are made. The combination of these evaluations and the large number of customers tends to limit the risk of credit concentration to an acceptable level.

Cash equivalents are placed with several major financial institutions, which limits the Company's exposure to credit risk. The Company controls credit risk on derivatives through credit approvals and monitoring procedures and believes that such risks are minimal because counterparties to the majority of transactions are major financial institutions.

Note K – Stockholder Rights Plan

The Company's Stockholder Rights Plan provides for each Common stockholder to receive a dividend of one Right for each share of the Company's Common Stock held. The Rights will expire on April 6, 2008 unless earlier redeemed or exchanged. The Rights will detach from the Common Stock and become exercisable following a specified period of time after the first public announcement that a person or group of affiliated or associated persons (other than certain persons) has become the beneficial owner of 15% or more of the Company's Common Stock. The Rights have certain antitakeover effects and will cause substantial dilution to a person or group that attempts to acquire the Company without conditioning the offer on a substantial number of Rights being acquired. The Rights are not intended to prevent a takeover, but rather are designed to enhance the ability of the Board of Directors to negotiate with an acquiror on behalf of all shareholders. Other terms of the Rights are set forth in, and the foregoing description is qualified in its entirety by, the Rights Agreement, as amended, between the Company and Harris Trust Company of New York as Rights Agent.

Note L – Earnings per Share

The following table reconciles the weighted-average shares outstanding for computation of basic and diluted income per Common share for each of the three years ended December 31, 2003. No difference existed between net income used in computing basic and diluted income per Common share for these years. There were no antidilutive options for the periods presented.

(Weighted-average shares outstanding)	**2003**	2002	2001
Basic method	**91,814,821**	91,450,836	90,442,944
Dilutive stock options	**927,945**	684,131	739,054
Diluted method	**92,742,766**	92,134,967	91,181,998

Note M – Other Financial Information

INVENTORIES – Inventories accounted for under the LIFO method totaled $144,347,000 and $95,825,000 at December 31, 2003 and 2002, respectively, and were $155,936,000 and $129,044,000 less than such inventories would have been valued using the FIFO method.

ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) – At December 31, 2003 and 2002, the components of Accumulated Other Comprehensive Income (Loss) were as follows.

(Thousands of dollars)	**2003**	2002
Foreign currency translation gain (loss), net	**$ 88,589**	$(56,984)
Cash flow hedge gains (losses), net	**9,458**	(8,454)
Minimum pension liability, net	**(32,801)**	(1,352)
Balance at end of year	**$ 65,246**	$(66,790)

At December 31, 2003, components of the net foreign currency translation gain of $88,589,000 were gains of $48,956,000 for pounds sterling, $38,955,000 for Canadian dollars and $678,000 for other currencies. Comparability of net income was not significantly affected by exchange rate fluctuations in 2003, 2002 and 2001. Net gains from foreign currency transactions included in the Consolidated Statements of Income were $2,892,000 in 2003, $792,000 in 2002 and $1,406,000 in 2001.

CASH FLOW DISCLOSURES – Cash income taxes paid were $86,750,000, $28,531,000 and $135,734,000 in 2003, 2002 and 2001, respectively. Interest paid, net of amounts capitalized, was $17,501,000, $20,977,000 and $12,945,000 in 2003, 2002 and 2001, respectively.

Noncash operating working capital increased for each of the three years ended December 31, 2003 as follows.

(Thousands of dollars)	**2003**	2002	2001
Accounts receivable	**$(41,419)**	$(146,760)	$ 207,594
Inventories	**(69,166)**	(28,196)	(8,393)
Prepaid expenses	**15,183**	1,100	(37,113)
Deferred income tax assets	**(1,825)**	662	6,139
Accounts payable and accrued liabilities	**60,380**	135,800	(176,213)
Current income tax liabilities	**21,934**	13,181	(19,965)
Net increase in noncash operating working capital	**$(14,913)**	$ (24,213)	$ (27,951)

Note N – Commitments

The Company leases land, gasoline stations and other facilities under operating leases. During the next five years, future minimum rental commitments under noncancellable operating leases are approximately $16,582,000 in 2004; $15,698,000 in 2005; $14,545,000 in 2006; $14,135,000 in 2007 and $13,236,000 in 2008. Rental expense for noncancellable operating leases, including contingent payments when applicable, was $32,869,000 in 2003, $32,087,000 in 2002 and $23,859,000 in 2001. Additionally, to assure long-term supply of hydrogen at its Meraux, Louisiana refinery, the Company has contracted to purchase up to 35 million standard cubic feet of hydrogen per day at market prices through 2018. The contract requires the payment of a base facility charge for use of the facility. Future required minimum annual payments for base facility charges are $4,352,000 in 2004, $5,604,000 for each of the years 2005 through 2009, and $55,106,000 in all later years. Base facility charges and hydrogen costs incurred in 2003 totaled $1,128,000. The Company has an Operating and Production Handling Agreement providing for processing and production handling services for hydrocarbon production from certain fields in the Gulf of Mexico. This agreement requires minimum annual payments for processing charges for the periods from 2004 through 2009. Under the agreement, the Company must make specified minimum payments quarterly. Future required minimum payments are $22,500,000 in 2004; $19,300,000 in 2005; $15,340,000 in 2006; $12,596,000 in 2007; $9,508,000 in 2008; and $13,272,000 thereafter. In addition, the Company is required to pay additional amounts depending on the actual hydrocarbon quantities processed under the agreement. Additionally, the Company has a Reserved Capacity Service Agreement providing for the availability of needed crude oil storage capacity for certain oil fields through 2020. Under the agreement, the Company must make specified minimum payments monthly. Future required minimum annual payments are $1,796,000 in 2004 through 2008; $1,144,000 in 2009 and $12,301,000 in later years. In addition, the Company is required to pay additional amounts depending on actual crude oil quantities under the agreement. Total payments under the agreement were $1,965,000 in 2003, $1,435,000 in 2002, and $1,805,000 in 2001.

Commitments for capital expenditures were approximately $456,400,000 at December 31, 2003, including $38,931,000 for costs to develop deepwater Gulf of Mexico fields, $84,160,000 for continued expansion of synthetic oil operations in Canada, and $117,400,000 for future work commitments in Malaysia.

Note O – 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, may be taken without full consideration of their consequences, and may be taken in response to actions of other governments, it is not practical to attempt to predict the likelihood of such actions, the form the actions may take or the effect such actions may have on the Company.

ENVIRONMENTAL MATTERS AND LEGAL MATTERS – 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, five terminals, and approximately 82 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, which is generally provided for by the Company's abandonment liability. Environmental laws and regulations are described more fully beginning on page 17 of this Form 10-K report.

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 $3,000,000.

The U.S. Environmental Protection Agency (EPA) currently considers the Company 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. Based on currently available information, the Company believes that it is a de minimus party as to ultimate responsibility at both Superfund sites. 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 two sites 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.

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$3.61 billion. The Company believes that the counterclaim is without merit and that the amount of damages sought is frivolous. Trial will likely begin in January 2005. 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, 17 class action lawsuits have been filed seeking damages for area residents. All the lawsuits have been administratively consolidated into a single legal action. The Company maintains liability insurance that covers such matters, and it recorded the applicable insurance deductible as an expense in 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.

OTHER MATTERS – In the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide financial guarantees or letters of credit that may be drawn upon if the Company fails to perform under those contracts. At December 31, 2003, the Company had contingent liabilities of $9,052,000 under a financial guarantee described in the following paragraph and $36,500,000 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 are remote.

The Company owns a 3.2% interest in the Louisiana Offshore Oil Port (LOOP) that it accounts for at cost. LOOP has issued $397,070,000 in bonds, which mature in varying amounts between 2004 and 2021. The Company is obligated to ship crude oil in quantities sufficient for LOOP to pay certain of its expenses and obligations, including long-term debt secured by a Throughput and Deficiency agreement (T&D), or to make cash payments for which the Company will receive credit for future throughput. No other collateral secures the investee's obligation or the Company's guarantee. As of December 31, 2003, it is not probable that the Company will be required to make payments under the guarantee; therefore, no liability has been recorded for the Company's obligation under the T&D agreement. The Company continues to monitor conditions that are subject to guarantees to identify whether it is probable that a loss has occurred, and would recognize any such losses under the guarantees should losses become probable.

Note P – Common Stock Issued and Outstanding

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2003 is shown below.

(Number of shares outstanding)	**2003**	2002	2001
At beginning of year	**91,689,454**	45,331,080	45,045,545
Stock options exercised	**86,500**	491,700	261,200
Employee stock purchase plans	**30,560**	28,647	24,896
Restricted stock awards (forfeitures)	**64,084**	–	(750)
Two-for-one stock split	–	45,838,065	–
All other	–	(38)	189
At end of year	**91,870,598**	91,689,454	45,331,080

Note Q – Subsequent Event (Unaudited)

In December 2003, the Company announced its intent to sell most of its conventional oil and gas assets in Western Canada. The assets are expected to be packaged together and offered for sale as a single unit. The marketing of the assets began in February 2004 and the sale is expected to close in the second quarter of 2004. The Company expects to utilize the proceeds of the sale to fund operations in Malaysia and other areas. The assets to be sold produce about 20,000 barrels of oil equivalent per day and have total reserves of approximately 46 million barrels equivalent. The properties to be sold are expected to be reported as discontinued operations beginning in the first quarter of 2004. At December 31, 2003, the major assets (liabilities) associated with the properties to be sold are as follows:

(Thousands of dollars)	
Property, plant and equipment, net of accumulated depreciation, depletion and amortization	$ 430,980
Goodwill	17,918
Other assets	4,511
Asset retirement obligations	(52,212)

The Company is unsure of the amount of tax pools that will be assigned to the assets to be sold.

Note R – Business Segments

Murphy's reportable segments are organized into two major types of business activities, each subdivided into geographic areas of operations. The Company's exploration and production activity is subdivided into segments for the United States, Canada, the United Kingdom, Ecuador, Malaysia and all other countries; each of these segments derives revenues primarily from the sale of crude oil and natural gas. The refining and marketing segments in North America and the United Kingdom derive revenues mainly from the sale of petroleum products. The Company sold its Canadian pipeline and trucking assets in May 2001. Operations for crude oil trading and transportation activities in Canada prior to sale of this operation in 2001 were included in the North American segment in past years. Beginning in 2002, the Company began selling gasoline in Canada at retail stations built in Wal-Mart parking lots. This business is considered by the Company to be an integrated operation similar to its U.S. business, and therefore, considers it appropriate to combine the Canadian business with its U.S. operation and report as one North American segment. The Company's management evaluates segment performance based on income from operations, excluding interest income and interest expense. Intersegment transfers of crude oil, natural gas and petroleum products are at market prices and intersegment services are recorded at cost.

Information about business segments and geographic operations is reported in the following tables. Excise taxes on petroleum products of $1,333,600,000, $1,147,922,000 and $1,005,018,000 for the years 2003, 2002 and 2001, respectively, were excluded from revenues and costs and expenses. For geographic purposes, revenues are attributed to the country in which the sale occurs. The Company had no single customer from which it derived more than 10% of its revenues. Corporate and other activities, including interest income, miscellaneous gains and losses, interest expense and unallocated overhead, are shown in the tables to reconcile the business segments to consolidated totals. As used in the table on page F-28, Certain Long-Lived Assets at December 31 exclude investments, noncurrent receivables, deferred tax assets and intangible assets.

Segment Information	**Exploration and Production**						
(Millions of dollars)	U.S.	Canada	U.K.	Ecuador	Malaysia	Other	Total
Year ended December 31, 2003							
Segment income (loss) from continuing operations	**$ 23.3**	**189.0**	**95.3**	**16.7**	**10.7**	**(8.8)**	**326.2**
Revenues from external customers	**196.7**	**586.9**	**221.6**	**41.9**	**77.7**	**4.2**	**1,129.0**
Intersegment revenues	–	**76.8**	–	–	–	–	**76.8**
Interest income	–	–	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–	–	–
Income tax expense (benefit)	**13.2**	**82.1**	**59.8**	**.6**	**3.7**	**.7**	**160.1**
Significant noncash charges (credits)							
Depreciation, depletion, amortization	**36.7**	**172.7**	**32.6**	**7.5**	**18.5**	**.2**	**268.2**
Impairment of properties	**3.0**	–	–	–	–	–	**3.0**
Provisions for major repairs	–	**6.5**	–	–	–	–	**6.5**
Amortization of undeveloped leases	**11.5**	**15.6**	**.1**	–	–	–	**27.2**
Deferred and noncurrent income taxes	**13.4**	**(5.1)**	**24.8**	–	**(7.0)**	**2.2**	**28.3**
Additions to property, plant, equipment	**229.9**	**204.6**	**24.5**	**27.0**	**152.8**	–	**638.8**
Total assets at year-end	**742.6**	**1,527.1**	**211.4**	**105.5**	**284.0**	**17.9**	**2,888.5**
Year ended December 31, 2002							
Segment income (loss) from continuing operations	$ (11.8)	157.0	49.6	12.0	(43.0)	(2.8)	161.0
Revenues from external customers	155.0	527.1	170.6	30.7	–	2.3	885.7
Intersegment revenues	3.3	83.4	–	–	–	–	86.7
Interest income	–	–	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–	–	–
Income tax expense (benefit)	(20.9)	79.8	42.3	–	–	(.9)	100.3
Significant noncash charges (credits)							
Depreciation, depletion, amortization	34.1	170.9	35.7	5.3	.9	.3	247.2
Impairment of properties	31.6	–	–	–	–	–	31.6
Provisions for major repairs	–	5.5	–	–	–	–	5.5
Amortization of undeveloped leases	10.5	14.1	–	–	–	–	24.6
Deferred and noncurrent income taxes	(18.7)	7.6	6.1	–	–	.6	(4.4)
Additions to property, plant, equipment	169.2	191.9	36.0	14.9	85.0	–	497.0
Total assets at year-end	661.8	1,269.9	243.7	82.0	122.1	7.9	2,387.4
Year ended December 31, 2001							
Segment income (loss) from continuing operations	$ 55.3	85.5	78.6	11.5	(36.1)	(7.3)	187.5
Revenues from external customers	223.1	366.5	194.2	33.4	–	2.2	819.4
Intersegment revenues	3.8	81.2	–	–	–	–	85.0
Interest income	–	–	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–	–	–
Income tax expense (benefit)	29.4	51.6	44.3	–	–	(1.0)	124.3
Significant noncash charges (credits)							
Depreciation, depletion, amortization	37.7	99.0	37.2	6.4	.5	.3	181.1
Amortization of goodwill	–	3.1	–	–	–	–	3.1
Impairment of properties	8.9	–	–	–	–	–	8.9
Provisions for major repairs	–	3.3	–	–	–	–	3.3
Amortization of undeveloped leases	9.5	13.6	–	–	–	–	23.1
Deferred and noncurrent income taxes	27.0	53.2	(3.3)	–	–	.5	77.4
Additions to property, plant, equipment	222.8	287.0	17.9	9.0	9.6	–	546.3
Total assets at year-end	582.1	1,255.8	213.5	69.9	22.2	7.5	2,151.0

Geographic Information	**Certain Long-Lived Assets at December 31**						
(Millions of dollars)	U.S.	Canada	U.K.	Ecuador	Malaysia	Other	Total
2003	**$1,514.9**	**1,386.8**	**295.6**	**89.9**	**243.3**	**7.8**	**3,538.3**
2002	1,302.2	1,116.8	295.0	70.9	101.8	6.3	2,893.0
2001	1,058.8	1,117.5	272.3	61.6	17.7	5.7	2,533.6

Segment Information (Continued)	Refining and Marketing			Corp. &	
(Millions of dollars)	North America	U.K.	Total	Other	Consolidated
Year ended December 31, 2003					
Segment income (loss) from continuing operations	**$ (21.2)**	**10.0**	**(11.2)**	**(13.8)**	**301.2**
Revenues from external customers	**3,722.4**	**483.8**	**4,206.2**	**10.0**	**5,345.2**
Intersegment revenues	–	–	–	–	**76.8**
Interest income	–	–	–	**4.4**	**4.4**
Interest expense, net of capitalization	–	–	–	**20.5**	**20.5**
Income tax expense (benefit)	**(11.9)**	**5.8**	**(6.1)**	**(36.0)**	**118.0**
Significant noncash charges (credits)					
Depreciation, depletion, amortization	**49.4**	**8.2**	**57.6**	**2.7**	**328.5**
Impairment of properties	**5.3**	–	**5.3**	–	**8.3**
Provisions for major repairs	**18.5**	**3.4**	**21.9**	**.1**	**28.5**
Amortization of undeveloped leases	–	–	–	–	**27.2**
Deferred and noncurrent income taxes	**(13.3)**	**(.6)**	**(13.9)**	**(10.4)**	**4.0**
Additions to property, plant, equipment	**205.8**	**9.6**	**215.4**	**1.1**	**855.3**
Total assets at year-end	**1,254.1**	**253.3**	**1,507.4**	**316.7**	**4,712.6**
Year ended December 31, 2002					
Segment income (loss) from continuing operations	$ (39.2)	(.7)	(39.9)	(23.6)	97.5
Revenues from external customers	2,688.7	404.5	3,093.2	5.4	3,984.3
Intersegment revenues	–	–	–	–	86.7
Interest income	–	–	–	5.4	5.4
Interest expense, net of capitalization	–	–	–	27.0	27.0
Income tax expense (benefit)	(20.7)	1.5	(19.2)	(26.9)	54.2
Significant noncash charges (credits)					
Depreciation, depletion, amortization	43.4	6.7	50.1	2.7	300.0
Impairment of properties	–	–	–	–	31.6
Provisions for major repairs	16.7	2.7	19.4	.1	25.0
Amortization of undeveloped leases	–	–	–	–	24.6
Deferred and noncurrent income taxes	13.4	(.5)	12.9	(2.6)	5.9
Additions to property, plant, equipment	230.4	4.3	234.7	1.1	732.8
Total assets at year-end	996.6	211.6	1,208.2	290.2	3,885.8
Year ended December 31, 2001					
Segment income (loss) from continuing operations	$ 139.6	14.1	153.7	(12.8)	328.4
Revenues from external customers	2,674.0	360.9	3,034.9	11.7	3,866.0
Intersegment revenues	.2	–	.2	–	85.2
Interest income	–	–	–	11.6	11.6
Interest expense, net of capitalization	–	–	–	19.0	19.0
Income tax expense (benefit)	71.2	5.0	76.2	(26.8)	173.7
Significant noncash charges (credits)					
Depreciation, depletion, amortization	36.9	6.1	43.0	2.5	226.6
Amortization of goodwill	–	–	–	–	3.1
Impairment of properties	1.6	–	1.6	–	10.5
Provisions for major repairs	15.7	1.9	17.6	.1	21.0
Amortization of undeveloped leases	–	–	–	–	23.1
Deferred and noncurrent income taxes	2.5	2.5	5.0	(2.3)	80.1
Additions to property, plant, equipment	162.8	12.4	175.2	5.8	727.3
Total assets at year-end	734.4	184.4	918.8	189.3	3,259.1

Geographic Information	Revenues from External Customers for the Year						
(Millions of dollars)	U.S.	U.K.	Canada	Ecuador	Malaysia	Other	Total
2003	**$3,883.4**	**706.5**	**631.5**	**41.9**	**77.7**	**4.2**	**5,345.2**
2002	2,843.4	578.0	529.9	30.7	–	2.3	3,984.3
2001	2,788.4	562.7	479.3	33.4	–	2.2	3,866.0

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

The following schedules are presented in accordance with SFAS No. 69, Disclosures about Oil and Gas Producing Activities, to provide users with a common base for preparing estimates of future cash flows and comparing reserves among companies. Additional background information follows concerning four of the schedules.

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

The U.S. Securities and Exchange Commission defines proved reserves as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered as a result of additional investments for drilling new wells to offset productive units, recompleting existing wells, and/or installing facilities to collect and transport production.

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

Oil reserves in Ecuador are derived from a participation contract covering Block 16 in the Amazon region. Oil reserves associated with the participation contract in Ecuador totaled 30.4 million barrels at December 31, 2003. Oil reserves in Malaysia are associated with a production sharing contract for Block SK 309. Malaysia reserves include oil to be received for both cost recovery and profit provisions under the contract. Oil reserves associated with the production sharing contract in Malaysia totaled 16.9 million barrels at December 31, 2003.

The Company has no proved reserves attributable to investees accounted for by the equity method.

Synthetic oil reserves in Canada, shown in a separate table following the reserve table at Schedule 1, are attributable to Murphy's share, after deducting estimated net profit royalty, of the Syncrude project and include currently producing leases. Additional reserves will be added as development progresses.

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

SCHEDULE 5 – STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES – SFAS No. 69 requires calculation of future net cash flows using a 10% annual discount factor and year-end prices, costs and statutory tax rates, except for known future changes such as contracted prices and legislated tax rates. Future net cash flows from the Company's interest in synthetic oil are excluded.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future cash flows because prices, costs and governmental policies do not remain static; appropriate discount rates may vary; and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts. Average year-end 2003 crude oil prices used for this calculation were $28.83 per barrel for the United States, $28.33 for Canadian light, $18.52 for Canadian heavy, $27.85 for Canadian offshore, $29.64 for the United Kingdom, $22.53 for Ecuador and $32.15 for Malaysia. Average year-end 2003 natural gas prices used were $6.17 per MCF for the United States, $4.56 for Canada and $4.17 for the United Kingdom.

Schedule 5 also presents the principal reasons for change in the standardized measure of discounted future net cash flows for each of the three years ended December 31, 2003.

Schedule 1 – Estimated Net Proved Oil Reserves

(Millions of barrels)	United States*	Canada	United Kingdom	Ecuador	Malaysia	Total
Proved						
December 31, 2000	45.3	63.9	51.0	40.9	–	201.1
Revisions of previous estimates	(.8)	2.8	.5	(.3)	–	2.2
Improved recovery	–	1.5	–	–	–	1.5
Purchases	–	.2	–	–	–	.2
Extensions and discoveries	46.2	3.3	–	–	15.0	64.5
Production	(2.1)	(9.4)	(7.4)	(1.9)	–	(20.8)
Sales	–	(1.8)	–	–	–	(1.8)
December 31, 2001	88.6	60.5	44.1	38.7	15.0	246.9
Revisions of previous estimates	(6.5)	6.6	3.7	(4.1)	.3	–
Extensions and discoveries	3.8	8.4	2.0	–	–	14.2
Production	(1.9)	(13.5)	(6.7)	(1.7)	–	(23.8)
Sales	(3.4)	(2.3)	–	–	–	(5.7)
December 31, 2002	80.6	59.7	43.1	32.9	15.3	231.6
Revisions of previous estimates	(1.7)	8.0	.4	(.6)	.5	6.6
Extensions and discoveries	1.0	10.2	–	–	3.8	15.0
Production	(1.7)	(15.0)	(5.4)	(1.9)	(2.7)	(26.7)
Sales	–	(2.9)	(9.8)	–	–	(12.7)
December 31, 2003	**78.2**	**60.0**	**28.3**	**30.4**	**16.9**	**213.8**
Proved Developed						
December 31, 2000	10.3	34.3	36.3	20.1	–	101.0
December 31, 2001	8.8	37.9	33.3	21.3	–	101.3
December 31, 2002	5.2	47.1	36.2	19.0	–	107.5
December 31, 2003	**23.9**	**47.7**	**24.4**	**17.7**	**4.6**	**118.3**

* Includes net proved oil reserves related to discontinued operation of 2.0 million barrels at December 31, 2001 and 3.0 million barrels at December 31, 2000.

Information on Proved Reserves for Canadian Synthetic Oil Operation Not Included in Above Reserves

The Company has a 5% interest in Syncrude, the world's largest tar sands synthetic oil production project located in Alberta, Canada. In addition to conventional liquids and natural gas proved reserves, Murphy has significant proved synthetic oil reserves associated with Syncrude that are shown in the table below. For internal management purposes, Murphy views these reserves and ongoing production and development as an integral part of its total Exploration and Production operations. However, the U.S. Securities and Exchange Commission's regulations define Syncrude as a mining operation, and therefore, does not permit these associated proved reserves to be included as a part of conventional oil and natural gas reserves. These reserves are also not included in the Company's schedule of Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, which can be found on page F-36.

Synthetic Oil Proved Reserves
(Millions of barrels)

At December 31, 2000	125.0
At December 31, 2001	131.0
At December 31, 2002	136.2
At December 31, 2003	**136.8**

Schedule 2 – Estimated Net Proved Natural Gas Reserves

(Billions of cubic feet)	United States*	Canada	United Kingdom	Total
Proved				
December 31, 2000	369.0	293.6	34.8	697.4
Revisions of previous estimates	(20.2)	(2.1)	4.9	(17.4)
Improved recovery	–	.9	–	.9
Purchases	–	30.7	–	30.7
Extensions and discoveries	89.0	44.7	–	133.7
Production	(42.1)	(56.6)	(4.8)	(103.5)
Sales	–	(1.7)	–	(1.7)
December 31, 2001	395.7	309.5	34.9	740.1
Revisions of previous estimates	(84.2)	(7.5)	(1.5)	(93.2)
Purchases	–	.4	–	.4
Extensions and discoveries	3.8	12.7	–	16.5
Production	(33.6)	(72.1)	(2.6)	(108.3)
Sales	(13.2)	(17.1)	–	(30.3)
December 31, 2002	268.5	225.9	30.8	525.2
Revisions of previous estimates	(4.5)	(8.6)	.1	(13.0)
Extensions and discoveries	14.7	16.8	–	31.5
Production	(30.0)	(45.1)	(3.5)	(78.6)
Sales	–	(15.8)	–	(15.8)
December 31, 2003	**248.7**	**173.2**	**27.4**	**449.3**
Proved Developed				
December 31, 2000	233.8	255.2	32.3	521.3
December 31, 2001	189.6	277.5	34.1	501.2
December 31, 2002	139.7	205.6	30.1	375.4
December 31, 2003	**150.5**	**156.0**	**26.6**	**333.1**

* Includes net proved natural gas reserves related to discontinued operations of 8.1 billion cubic feet at December 31, 2001 and 11.7 billion at December 31, 2000.

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

(Millions of dollars)	United States[1]	Canada[2]	United Kingdom	Ecuador	Malaysia	Other	Total
Year Ended December 31, 2003							
Property acquisition costs							
Unproved	**$ 19.9**	**4.5**	**–**	**–**	**–**	**–**	**24.4**
Proved	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Total acquisition costs	**19.9**	**4.5**	**–**	**–**	**–**	**–**	**24.4**
Exploration costs	**72.5**	**49.9**	**.3**	**–**	**68.9**	**5.1**	**196.7**
Development costs	**189.4**	**91.4**	**24.5**	**27.0**	**115.5**	**–**	**447.8**
Total capital expenditures	**281.8**	**145.8**	**24.8**	**27.0**	**184.4**	**5.1**	**668.9**
Asset retirement costs	**13.6**	**6.1**	**–**	**–**	**5.7**	**–**	**25.4**
Charged to expense							
Dry hole expense	**36.4**	**24.7**	**(.1)**	**–**	**17.6**	**3.9**	**82.5**
Geophysical and other costs	**15.5**	**10.3**	**.4**	**–**	**14.0**	**1.2**	**41.4**
Total charged to expense	**51.9**	**35.0**	**.3**	**–**	**31.6**	**5.1**	**123.9**
Property additions	**$243.5**	**116.9**	**24.5**	**27.0**	**158.5**	**–**	**570.4**
Year Ended December 31, 2002							
Property acquisition costs							
Unproved	$ 8.4	10.1	–	–	–	–	18.5
Proved	–	.6	–	–	–	–	.6
Total acquisition costs	8.4	10.7	–	–	–	–	19.1
Exploration costs	56.7	68.8	3.8	–	102.3	.2	231.8
Development costs	156.7	87.0	36.0	14.9	24.8	–	319.4
Total capital expenditures	221.8	166.5	39.8	14.9	127.1	.2	570.3
Charged to expense							
Dry hole expense	39.8	20.3	3.1	–	37.9	.1	101.2
Geophysical and other costs	12.8	15.8	.7	–	4.2	.1	33.6
Total charged to expense	52.6	36.1	3.8	–	42.1	.2	134.8
Property additions[3]	$169.2	130.4	36.0	14.9	85.0	–	435.5
Year Ended December 31, 2001							
Property acquisition costs							
Unproved	$ 40.1	25.1	–	–	–	–	65.2
Proved	.3	21.3	–	–	–	–	21.6
Total acquisition costs	40.4	46.4	–	–	–	–	86.8
Exploration costs	86.5	105.9	.9	–	44.3	4.6	242.2
Development costs	128.7	167.4	17.9	9.0	.9	–	323.9
Total capital expenditures	255.6	319.7	18.8	9.0	45.2	4.6	652.9
Charged to expense							
Dry hole expense	23.7	47.0	.1	–	8.4	3.6	82.8
Geophysical and other costs	9.1	12.9	.8	–	27.2	1.0	51.0
Total charged to expense	32.8	59.9	.9	–	35.6	4.6	133.8
Property additions[3]	$222.8	259.8	17.9	9.0	9.6	–	519.1

[1] Excludes $.5 million in 2002 and $3.4 million in 2001 related to discontinued operations.

[2] Excludes costs incurred for the Company's 5% interest in synthetic oil operations in Canada, which were $93.8 million in 2003, $61.5 million in 2002 and $27.2 million in 2001.

[3] Excludes pro forma asset retirement costs, assuming SFAS No. 143 had been applied retroactively, of $8.3 million and $10.1 million in 2002 and 2001, respectively.

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

(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Malaysia	Other	Subtotal	Synthetic Oil – Canada	Total
Year Ended December 31, 2003									
Revenues									
Crude oil and natural gas liquids									
Transfers to consolidated operations	**$ –**	**59.8**	**–**	**–**	**–**	**–**	**59.8**	**17.0**	**76.8**
Sales to unaffiliated enterprises	**39.2**	**293.5**	**158.6**	**41.9**	**77.7**	**–**	**610.9**	**78.7**	**689.6**
Natural gas									
Transfers to consolidated operations	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Sales to unaffiliated enterprises	**158.3**	**203.8**	**12.2**	**–**	**–**	**–**	**374.3**	**–**	**374.3**
Total oil and gas revenues	**197.5**	**557.1**	**170.8**	**41.9**	**77.7**	**–**	**1,045.0**	**95.7**	**1,140.7**
Other operating revenues	**(.8)**	**10.9**	**50.8**	**–**	**–**	**4.2**	**65.1**	**–**	**65.1**
Total revenues	**196.7**	**568.0**	**221.6**	**41.9**	**77.7**	**4.2**	**1,110.1**	**95.7**	**1,205.8**
Costs and expenses									
Production expenses	**36.8**	**81.0**	**27.9**	**16.5**	**9.1**	**–**	**171.3**	**62.9**	**234.2**
Exploration costs charged to expense	**51.9**	**35.0**	**.3**	**–**	**31.6**	**5.1**	**123.9**	**–**	**123.9**
Undeveloped lease amortization	**11.5**	**15.6**	**.1**	**–**	**–**	**–**	**27.2**	**–**	**27.2**
Depreciation, depletion and amortization	**36.7**	**163.6**	**32.6**	**7.5**	**18.5**	**.2**	**259.1**	**9.1**	**268.2**
Impairment of properties	**3.0**	**–**	**–**	**–**	**–**	**–**	**3.0**	**–**	**3.0**
Accretion on discounted liabilities	**3.3**	**5.1**	**2.9**	**–**	**.3**	**.3**	**11.9**	**.4**	**12.3**
Selling and general expenses	**17.0**	**19.3**	**2.7**	**.6**	**3.8**	**6.7**	**50.1**	**.6**	**50.7**
Total costs and expenses	**160.2**	**319.6**	**66.5**	**24.6**	**63.3**	**12.3**	**646.5**	**73.0**	**719.5**
	36.5	**248.4**	**155.1**	**17.3**	**14.4**	**(8.1)**	**463.6**	**22.7**	**486.3**
Income tax expense	**13.2**	**77.8**	**59.8**	**.6**	**3.7**	**.7**	**155.8**	**4.3**	**160.1**
Results of operations*	**$ 23.3**	**170.6**	**95.3**	**16.7**	**10.7**	**(8.8)**	**307.8**	**18.4**	**326.2**
Year Ended December 31, 2002									
Revenues									
Crude oil and natural gas liquids									
Transfers to consolidated operations	$ –	51.7	–	–	–	–	51.7	31.7	83.4
Sales to unaffiliated enterprises	30.0	253.1	163.0	30.7	–	–	476.8	74.6	551.4
Natural gas									
Transfers to consolidated operations	3.3	–	–	–	–	–	3.3	–	3.3
Sales to unaffiliated enterprises	108.0	197.6	7.0	–	–	–	312.6	–	312.6
Total oil and gas revenues	141.3	502.4	170.0	30.7	–	–	844.4	106.3	950.7
Other operating revenues	17.0	1.8	.6	–	–	2.3	21.7	–	21.7
Total revenues	158.3	504.2	170.6	30.7	–	2.3	866.1	106.3	972.4
Costs and expenses									
Production expenses	43.7	88.5	35.9	12.8	–	–	180.9	48.7	229.6
Cost to repair storm damages	5.0	–	–	–	–	–	5.0	–	5.0
Exploration costs charged to expense	52.6	36.1	3.8	–	42.1	.2	134.8	–	134.8
Undeveloped lease amortization	10.5	14.1	–	–	–	–	24.6	–	24.6
Depreciation, depletion and amortization	34.1	162.1	35.7	5.3	.9	.3	238.4	8.8	247.2
Impairment of properties	31.6	–	–	–	–	–	31.6	–	31.6
Selling and general expenses	13.5	15.1	3.3	.6	–	5.5	38.0	.3	38.3
Total costs and expenses	191.0	315.9	78.7	18.7	43.0	6.0	653.3	57.8	711.1
	(32.7)	188.3	91.9	12.0	(43.0)	(3.7)	212.8	48.5	261.3
Income tax expense (benefit)	(20.9)	64.2	42.3	–	–	(.9)	84.7	15.6	100.3
Results of operations*	$ (11.8)	124.1	49.6	12.0	(43.0)	(2.8)	128.1	32.9	161.0

* Excludes corporate overhead and interest in 2003 and 2002 and discontinued operations in 2002. Income from discontinued operations was $14 million in 2002. Results of operations in 2002 excludes pro forma accretion on discounted liabilities of $10.3 million.

Schedule 4 – Results of Operations for Oil and Gas Producing Activities (Contd.)

(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Malaysia	Other	Subtotal	Synthetic Oil – Canada	Total
Year Ended December 31, 2001									
Revenues									
Crude oil and natural gas liquids									
Transfers to consolidated operations	$ –	50.6	–	–	–	–	50.6	30.6	81.2
Sales to unaffiliated enterprises	38.5	116.6	181.5	33.4	–	–	370.0	65.2	435.2
Natural gas									
Transfers to consolidated companies	3.8	–	–	–	–	–	3.8	–	3.8
Sales to unaffiliated enterprises	189.0	182.6	12.1	–	–	–	383.7	–	383.7
Total oil and gas revenues	231.3	349.8	193.6	33.4	–	–	808.1	95.8	903.9
Other operating revenues	(4.4)	2.1	.6	–	–	2.2	.5	–	.5
Total revenues	226.9	351.9	194.2	33.4	–	2.2	808.6	95.8	904.4
Costs and expenses									
Production expenses	41.4	72.0	30.8	14.9	–	–	159.1	51.9	211.0
Exploration costs charged to expense	32.8	59.9	.9	–	35.6	4.6	133.8	–	133.8
Undeveloped lease amortization	9.5	13.6	–	–	–	–	23.1	–	23.1
Depreciation, depletion and amortization	37.7	90.7	37.2	6.4	.5	.3	172.8	8.3	181.1
Amortization of goodwill	–	3.1	–	–	–	–	3.1	–	3.1
Impairment of properties	8.9	–	–	–	–	–	8.9	–	8.9
Selling and general expenses	11.9	11.0	2.4	.6	–	5.6	31.5	.1	31.6
Total costs and expenses	142.2	250.3	71.3	21.9	36.1	10.5	532.3	60.3	592.6
	84.7	101.6	122.9	11.5	(36.1)	(8.3)	276.3	35.5	311.8
Income tax expense (benefit)	29.4	39.1	44.3	–	–	(1.0)	111.8	12.5	124.3
Results of operations*	$ 55.3	62.5	78.6	11.5	(36.1)	(7.3)	164.5	23.0	187.5

* Excludes discontinued operations, corporate overhead and interest in 2001. Income from discontinued operations was $2.5 million in 2001. Excludes pro forma accretion on discounted liabilities of $10.9 million in 2001.

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

(Millions of dollars)	United States[1]	Canada[2]	United Kingdom	Ecuador	Malaysia	Total
December 31, 2003						
Future cash inflows	**$ 3,787.5**	**2,239.6**	**948.2**	**685.1**	**544.6**	**8,205.0**
Future development costs	**(184.2)**	**(85.4)**	**(22.7)**	**(41.4)**	**(104.1)**	**(437.8)**
Future production and abandonment costs	**(631.1)**	**(649.5)**	**(268.8)**	**(264.6)**	**(143.2)**	**(1,957.2)**
Future income taxes	**(1,001.2)**	**(419.0)**	**(265.0)**	**(116.5)**	**(129.6)**	**(1,931.3)**
Future net cash flows	**1,971.0**	**1,085.7**	**391.7**	**262.6**	**167.7**	**3,878.7**
10% annual discount for estimated timing of cash flows	**(560.7)**	**(266.2)**	**(122.9)**	**(72.7)**	**(36.3)**	**(1,058.8)**
Standardized measure of discounted future net cash flows	**$ 1,410.3**	**819.5**	**268.8**	**189.9**	**131.4**	**2,819.9**
December 31, 2002						
Future cash inflows	$ 3,657.1	2,344.2	1,374.9	690.3	468.5	8,535.0
Future development costs	(332.0)	(57.0)	(55.2)	(64.5)	(83.6)	(592.3)
Future production and abandonment costs	(579.0)	(487.2)	(421.1)	(250.4)	(149.5)	(1,887.2)
Future income taxes	(905.7)	(579.7)	(376.8)	(116.7)	(84.6)	(2,063.5)
Future net cash flows	1,840.4	1,220.3	521.8	258.7	150.8	3,992.0
10% annual discount for estimated timing of cash flows	(633.6)	(291.3)	(160.0)	(88.2)	(38.5)	(1,211.6)
Standardized measure of discounted future net cash flows	$ 1,206.8	929.0	361.8	170.5	112.3	2,780.4
December 31, 2001						
Future cash inflows	$ 2,468.1	1,699.2	910.2	463.1	299.8	5,840.4
Future development costs	(490.1)	(98.5)	(61.1)	(63.2)	(70.9)	(783.8)
Future production and abandonment costs	(740.8)	(515.3)	(401.0)	(247.2)	(79.3)	(1,983.6)
Future income taxes	(365.3)	(287.7)	(139.7)	(37.8)	(61.0)	(891.5)
Future net cash flows	871.9	797.7	308.4	114.9	88.6	2,181.5
10% annual discount for estimated timing of cash flows	(372.8)	(211.5)	(94.0)	(45.3)	(31.5)	(755.1)
Standardized measure of discounted future net cash flows	$ 499.1	586.2	214.4	69.6	57.1	1,426.4

[1] Includes discounted future net cash flows from discontinued operations of $1.9 million at December 31, 2001.
[2] Excludes discounted future net cash flows from synthetic oil of $451.5 million at December 31, 2003, $411 million at December 31, 2002 and $188 million at December 31, 2001.

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

(Millions of dollars)	**2003**	2002	2001
Net changes in prices, production costs and development costs	**$ (97.0)**	$2,480.2	$(2,636.9)
Sales and transfers of oil and gas produced, net of production costs	**(938.8)**	(672.9)	(655.4)
Net change due to extensions and discoveries	**307.7**	238.8	691.6
Net change due to purchases and sales of proved reserves	**(196.7)**	(150.9)	19.3
Development costs incurred	**426.9**	304.3	308.7
Accretion of discount	**420.4**	202.5	390.6
Revisions of previous quantity estimates	**85.1**	(223.2)	1.4
Net change in income taxes	**31.9**	(824.8)	703.3
Net increase (decrease)	**39.5**	1,354.0	(1,177.4)
Standardized measure at January 1	**2,780.4**	1,426.4	2,603.8
Standardized measure at December 31	**$2,819.9**	$2,780.4	$ 1,426.4

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

(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Malaysia	Other	Subtotal	Synthetic Oil – Canada	Total
December 31, 2003									
Unproved oil and gas properties	**$ 125.3**	**120.8**	**.1**	**–**	**154.5**	**3.5**	**404.2**	**–**	**404.2**
Proved oil and gas properties	**1,516.6**	**1,751.9**	**614.1**	**269.7**	**93.7**	**–**	**4,246.0**	**425.5**	**4,671.5**
Asset retirement costs	**50.3**	**65.0**	**29.6**	**–**	**8.1**	**3.1**	**156.1**	**4.1**	**160.2**
Gross capitalized costs	**1,692.2**	**1,937.7**	**643.8**	**269.7**	**256.3**	**6.6**	**4,806.3**	**429.6**	**5,235.9**
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	**(24.6)**	**(52.0)**	**(.1)**	**–**	**–**	**(3.5)**	**(80.2)**	**–**	**(80.2)**
Proved oil and gas properties	**(1,018.2)**	**(833.3)**	**(429.9)**	**(179.8)**	**(16.3)**	**–**	**(2,477.5)**	**(71.8)**	**(2,549.3)**
Asset retirement costs	**(31.4)**	**(32.0)**	**(21.8)**	**–**	**(1.7)**	**(3.1)**	**(90.0)**	**(.3)**	**(90.3)**
Net capitalized costs	**$ 618.0**	**1,020.4**	**192.0**	**89.9**	**238.3**	**–**	**2,158.6**	**357.5**	**2,516.1**
December 31, 2002									
Unproved oil and gas properties	$ 129.1	98.1	.2	–	57.1	3.5	288.0	–	288.0
Proved oil and gas properties	1,487.5	1,443.0	915.9	242.8	42.7	–	4,131.9	267.9	4,399.8
Gross capitalized costs*	1,616.6	1,541.1	916.1	242.8	99.8	3.5	4,419.9	267.9	4,687.8
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	(31.2)	(45.8)	(.1)	–	–	(3.5)	(80.6)	–	(80.6)
Proved oil and gas properties	(1,033.1)	(601.9)	(714.7)	(171.9)	–	–	(2,521.6)	(51.1)	(2,572.7)
Net capitalized costs*	$ 552.3	893.4	201.3	70.9	99.8	–	1,817.7	216.8	2,034.5

* The pro forma gross and net capitalized costs as of December 31, 2002 assuming SFAS No. 143 had been applied retroactively is shown in the following table.

	United States	Canada	United Kingdom	Ecuador	Malaysia	Other	Subtotal	Synthetic Oil – Canada	Total
Gross capitalized costs	$ 1,658.0	1,592.4	957.2	242.8	102.1	6.2	4,558.7	271.3	4,830.0
Net capitalized costs	563.4	951.2	210.5	70.9	102.1	–	1,898.1	220.0	2,118.1

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

(Millions of dollars except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Year Ended December 31, 2003					
Sales and other operating revenues	**$1,321.3**	**$1,227.1**	**$1,284.9**	**$1,441.8**	**$5,275.1**
Income from continuing operations before income taxes	**125.3**	**127.9**	**90.6**	**75.4**	**419.2**
Income before cumulative effect of accounting change	**94.1**	**79.7**	**68.7**	**58.7**	**301.2**
Cumulative effect of accounting change	**(7.0)**	–	–	–	**(7.0)**
Net income	**87.1**	**79.7**	**68.7**	**58.7**	**294.2**
Income per Common share – basic					
Income before cumulative effect of accounting change	**1.03**	**.87**	**.75**	**.64**	**3.28**
Cumulative effect of accounting change	**(.08)**	–	–	–	**(.08)**
Net income	**.95**	**.87**	**.75**	**.64**	**3.20**
Income per Common share – diluted					
Income before cumulative effect of accounting change	**1.02**	**.86**	**.74**	**.63**	**3.25**
Cumulative effect of accounting change	**(.08)**	–	–	–	**(.08)**
Net income	**.94**	**.86**	**.74**	**.63**	**3.17**
Cash dividend per Common share	**.20**	**.20**	**.20**	**.20**	**.80**
Market price of Common Stock[1]					
High	**45.24**	**53.34**	**59.00**	**68.02**	**68.02**
Low	**38.84**	**40.87**	**47.58**	**57.52**	**38.84**
Year Ended December 31, 2002					
Sales and other operating revenues	$ 748.4	$1,034.9	$1,044.3	$1,138.9	$3,966.5
Income from continuing operations before income taxes	3.7	40.5	43.4	64.1	151.7
Income from continuing operations	2.4	12.9	36.5	45.7	97.5
Discontinued operations	.2	1.0	.9	11.9	14.0
Net income	2.6	13.9	37.4	57.6	111.5
Income per Common share – basic					
Income from continuing operations	.03	.14	.40	.50	1.07
Discontinued operations	–	.01	.01	.13	.15
Net income	.03	.15	.41	.63	1.22
Income per Common share – diluted					
Income from continuing operations	.03	.14	.40	.49	1.06
Discontinued operations	–	.01	.01	.13	.15
Net income	.03	.15	.41	.62	1.21
Cash dividend per Common share	.1875	.1875	.20	.20	.775
Market price of Common Stock[1,2]					
High	48.18	49.70	43.72	46.10	49.70
Low	38.25	40.95	32.47	38.15	32.47

[1] Prices are as quoted on the New York Stock Exchange.
[2] Market prices in 2002 have been adjusted to reflect the Company's two-for-one stock split on December 30, 2002.

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

(Millions of dollars)	Balance at January 1	Charged (Credited) to Expense	Deductions	Other*	Balance at December 31
2003					
Deducted from asset accounts:					
Allowance for doubtful accounts	**$ 9.3**	**2.8**	**(1.5)**	**.1**	**10.7**
Deferred tax asset valuation allowance	**89.6**	**(21.5)**	**–**	**–**	**68.1**
Included in liabilities:					
Accrued major repair costs	**53.0**	**28.5**	**(61.9)**	**.9**	**20.5**
2002					
Deducted from asset accounts:					
Allowance for doubtful accounts	$11.3	.8	(2.7)	(.1)	9.3
Deferred tax asset valuation allowance	67.7	21.9	–	–	89.6
Included in liabilities:					
Accrued major repair costs	44.6	25.0	(17.0)	.4	53.0
2001					
Deducted from asset accounts:					
Allowance for doubtful accounts	$10.2	2.3	(1.2)	–	11.3
Deferred tax asset valuation allowance	61.0	6.7	–	–	67.7
Included in liabilities:					
Accrued major repair costs	34.3	21.1	(10.5)	(.3)	44.6

*Amounts represent changes in foreign currency exchange rates.

GLOSSARY OF TERMS

bitumen or oil sands
tar-like hydrocarbon-bearing substance that occurs naturally in certain areas at the Earth's surface or at relatively shallow depths

clean fuels
low-sulfur content gasoline and diesel products

deepwater
offshore location in greater than 1,000 feet of water

downstream
refining and marketing operations

dry hole
an unsuccessful exploration well that is plugged and abandoned, with associated costs written off to expense

exploratory
wildcat and delineation, e.g., exploratory wells

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

hydrocarbons
organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products

on stream
commencement of oil and gas production from a new field

3D seismic
three-dimensional images created by bouncing sound waves off underground rock formations that are used to determine the best places to drill for hydrocarbons

throughput
average amount of raw material processed in a given period by a facility

upstream
oil and natural gas exploration and production operations, including synthetic oil operation

wildcat
well drilled to target an untested or unproved geologic formation

CORPORATE INFORMATION

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Stock Exchange Listings
Trading Symbol: MUR
New York Stock Exchange

MUR LISTED NYSE

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2 North LaSalle St.
Chicago, Illinois 60602
Toll-free (888) 239-5303
Local Chicago (312) 360-5303

E-mail Address
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www.murphyoilcorp.com
Murphy Oil's website provides frequently updated information about the Company and its operations, including:

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

Annual Meeting
The annual meeting of the Company's shareholders will be held at 10 a.m. on May 12, 2004, at the South Arkansas Arts Center, 110 East 5th Street, El Dorado, Arkansas. A formal notice of the meeting, together with a proxy statement and proxy form, will be mailed to all shareholders.

Inquiries
Inquiries regarding shareholder account matters should be addressed to:

Walter K. Compton
Secretary
Murphy Oil Corporation
P.O. Box 7000
El Dorado, Arkansas 71731-7000

Members of the financial community should direct their inquiries to:

Mindy K. West
Director of Investor Relations
Murphy Oil Corporation
P.O. Box 7000
El Dorado, Arkansas 71731-7000
(870) 864-6315

Electronic Payment of Dividends
Shareholders may have dividends deposited directly into their bank accounts by electronic funds transfer. Authorization forms may be obtained from:

Computershare Investor Services, L.L.C.
2 North LaSalle St.
Chicago, Illinois 60602
Toll-free (888) 239-5303
Local Chicago (312) 360-5303

PRINCIPAL OFFICES

El Dorado, Arkansas

New Orleans, Louisiana

Houston, Texas

Calgary, Alberta, Canada

St. Albans, Hertfordshire, England

Kuala Lumpur, Malaysia

MURPHY
OIL CORPORATION

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