MURPHY OIL CORPORATION

Annual Report 2002

Highlights

FINANCIAL

(Thousands of dollars except per share data)	2002	2001	2000
For the Year*			
Revenues	**$ 3,984,327**	3,865,968	3,658,186
Net income	**111,508**	330,903	296,828
Cash dividends paid	**70,898**	67,826	65,294
Capital expenditures	**868,100**	864,440	557,897
Net cash provided by operating activities	**532,844**	635,704	747,751
Average Common shares outstanding – diluted	**92,134,967**	91,181,998	90,479,412
At End of Year			
Working capital	**$ 136,268**	38,604	71,710
Net property, plant and equipment	**2,886,599**	2,525,807	2,184,719
Total assets	**3,885,775**	3,259,099	3,134,353
Long-term debt	**862,808**	520,785	524,759
Stockholders' equity	**1,593,553**	1,498,163	1,259,560
Per Share of Common Stock*			
Net income – diluted	**$ 1.21**	3.63	3.28
Cash dividends paid	**.775**	.75	.725
Stockholders' equity	**17.38**	16.53	13.98

*Includes nonrecurring items that are detailed in Management's Discussion and Analysis, page 10 of the attached Form 10-K report.

OPERATING

For the Year	2002	2001	2000
Net crude oil and gas liquids produced – barrels a day	**76,370**	67,355	65,259
United States	**5,285**	5,763	6,663
Canada	**48,239**	36,059	31,296
Other International	**22,846**	25,533	27,300
Net natural gas sold – thousands of cubic feet a day	**296,931**	281,235	229,412
United States	**92,106**	115,527	144,789
Canada	**197,852**	152,583	73,773
United Kingdom	**6,973**	13,125	10,850
Crude oil refined – barrels a day	**143,829**	167,199	165,820
North America	**114,189**	140,214	137,313
United Kingdom	**29,640**	26,985	28,507
Petroleum products sold – barrels a day	**210,631**	205,318	179,515
North America	**176,427**	174,256	149,612
United Kingdom	**34,204**	31,062	29,903

Letter to the Shareholders

Claiborne P. Deming

Perhaps the most significant event in 2002 was the Kikeh discovery in deepwater Block K (80%), offshore Malaysia. Murphy now holds a substantial acreage position in the Sabah Trough - a virtually undrilled geological province with only 13 wells that have yielded seven discoveries.

Dear Fellow Shareholder:

Net income in 2002 was $111.5 million, $1.21 per share, compared to $330.9 million in 2001, $3.63 per share. The decline was principally due to lower crude oil and natural gas prices at the beginning of the year, depressed downstream results throughout the year and lower gains on asset dispositions. As a partial offset, the Company averaged 125,800 barrels equivalent a day of production in 2002, establishing a record which should be surpassed in 2003 and again in 2004.

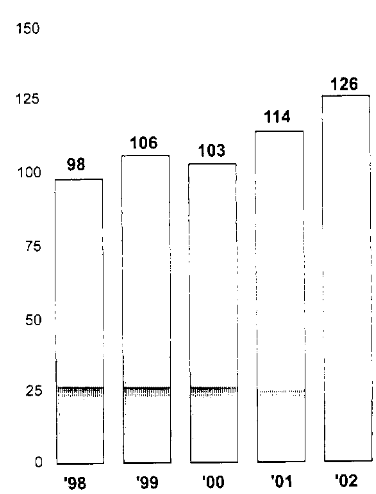
Despite lower earnings, much was accomplished in 2002 that strengthens and enhances the future growth of your Company. The Terra Nova field (12%) came on stream in the first quarter with minimal start-up problems and produced above expectation all year. This field along with the nearby Hibernia field (6.5%) will be sources of net income and cash flow for many years to come. In addition, development work continued at Medusa (60%), Habanero (33.75%) and Front Runner (37.5%) in the deepwater Gulf of Mexico; West Patricia (85%) in shallow-water Malaysia; Syncrude (5%) in northern Alberta, Canada; and Block 16 (20%) in Ecuador. All of these fields, or field expansions, come on stream within the next few years (Medusa, Habanero, West Patricia and Block 16 in 2003) and will materially add to the profitability and size of Murphy.

Also during the year we continued the construction of the green fuels project at the Meraux refinery. This project will be completed in the third quarter of 2003 at which time the newly expanded refinery will exclusively manufacture both low-sulfur diesel and gasoline well in advance of government mandated deadlines. In the retail marketing arena, the Company's presence at Wal-Mart sites expanded as we built our 500th Murphy USA station in the fourth quarter of 2002. The build-out is ongoing with the 600th site expected to open early in the fourth quarter of this year. Murphy is the clear market leader in this segment, owning approximately one out of every four hypermarket fuel retailing outlets in America.

Perhaps the most significant event in 2002 was the Kikeh discovery in deepwater Block K (80%), offshore Malaysia. We followed up the discovery well, which was drilled at mid-year, with two appraisal wells that confirmed a substantial new field. The Company

Net Hydrocarbons Produced

(thousands of oil equivalent barrels a day)



○ Ecuador and Other ○ United Kingdom
○ Canada ◍ United States

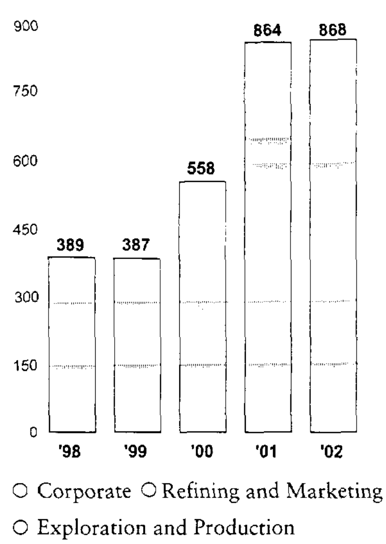
now holds a substantial acreage position in the Sabah Trough – a virtually undrilled geological province with only 13 wells that have yielded seven discoveries. We will drill a minimum of five wildcats in deepwater Malaysia in 2003 as we systematically set about exploring this massive and extremely prospective acreage position.

Murphy is the clear market leader in the hypermarket retail marketing segment, owning approximately one out of every four hypermarket fuel retailing outlets in America

We are taking advantage of the current frothy price environment to dispose of high-cost fields that no longer contribute to our portfolio. It is not without a touch of sadness that we sold the venerable Ship Shoal Block 113 unit (50–70%) in the Gulf of Mexico in 2002 and in early 2003 signed a letter of intent to sell the once super-giant Ninian field (13.82%) in the U.K. North Sea. Each field marked a milestone in the growth of your Company and were important sources of cash flow through some of the lean times in the 1980s. Cash lifting costs for these fields were in excess of $8.00 a barrel in 2002; it was clearly time to let them go. Importantly, new fields will more than replace this production and cash flow.

Capital Expenditures by Function

(millions of dollars)



We suffered some setbacks in 2002. Except for Kikeh, our explorers did not perform at their same outstanding level of the past several years, and for the first time in 12 years we did not replace our production. Given the frontier nature of your Company's exploratory program, this type of annual result is perhaps, at some point, unavoidable. Also, given the size and extent of our interest in the Sabah Trough, the events that occurred in 2002 should provide extraordinary impetus for future reserve growth. In addition, the Company's downstream business was bedeviled by weak refining and marketing margins much of the year exacerbated by poor ontime performance for the Meraux refinery. Returning to a more efficient operation at Meraux is a priority for 2003.

I am extremely sanguine regarding Murphy Oil Corporation's future. Your Company has a powerful combination of high-quality, low-cost producing fields that form the current core, soon to be augmented by the lineup of new production that comes on stream in 2003 and 2004. Furthermore, our exploration potential is as good as I have ever seen at Murphy. The Company's deepwater Gulf of Mexico 2003 prospect listing is outstanding, with up to six wildcats on tap. The portfolio in deepwater Malaysia is extensive in both quality and number. We have excellent opportunities for meaningful reserve additions this year in these programs. The Company's downstream business, anchored by our stations at Wal-Mart stores, is rapidly expanding its market share at the expense of less efficient competitors.

The Board of Directors signaled strong support for the future growth of the Company by increasing the dividend to $.80 a share (on a post-split basis) at mid-year. In addition, the Board split the stock two-for-one at the end of the year. The Board also added two extremely capable new members in February of 2003. Frank Blue, a lawyer who is Of Counsel with the firm of Fulbright & Jaworski, specializes in corporate governance. Frank was most recently Vice-President, General Counsel and Corporate Secretary with Caltex Corporation, one of the largest oil and gas firms operating in the Far East. Ivar Ramberg was most recently President and CEO of Norsk Hydro Canada. Before joining the industry, he had a distinguished university academic career in Norway and the U.S. teaching geology and geophysics.

Enoch Dawkins, President of Murphy Exploration & Production Company, will retire on March 1, 2003, and Herb Fox, Executive Vice President of Worldwide Downstream, will retire on April 1, 2003. Upon retirement, Enoch and Herb will have 39 and 33 years of service, respectively, with your Company. Each provided invaluable contributions to their respective disciplines and important assistance to the Company's broader goals. They are men of integrity and dedication and always put in the time required to get the job done. They will be missed.

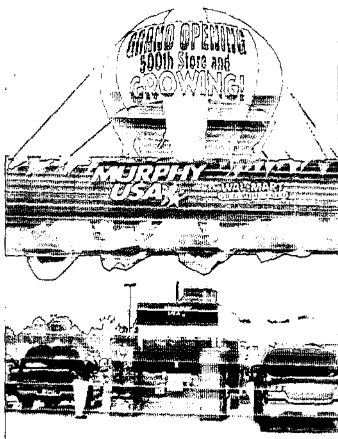
Charles H. Murphy, Jr. died March 20, 2002. He was a unique man with extraordinary insights not only into our industry but also the larger world. He inspired at least two generations of Murphy managers who were fortunate enough to work with him. Also, George Ishiyama died February 4, 2003. George was a director from 1976 to 1986 and a director emeritus from 1986 to 2003. He was a pioneer in promoting post-war, U.S.-Japanese trade development and a valued contributor to the Board.

As always, I appreciate your support and look forward with confidence to our shared future.

Claiborne P. Deming

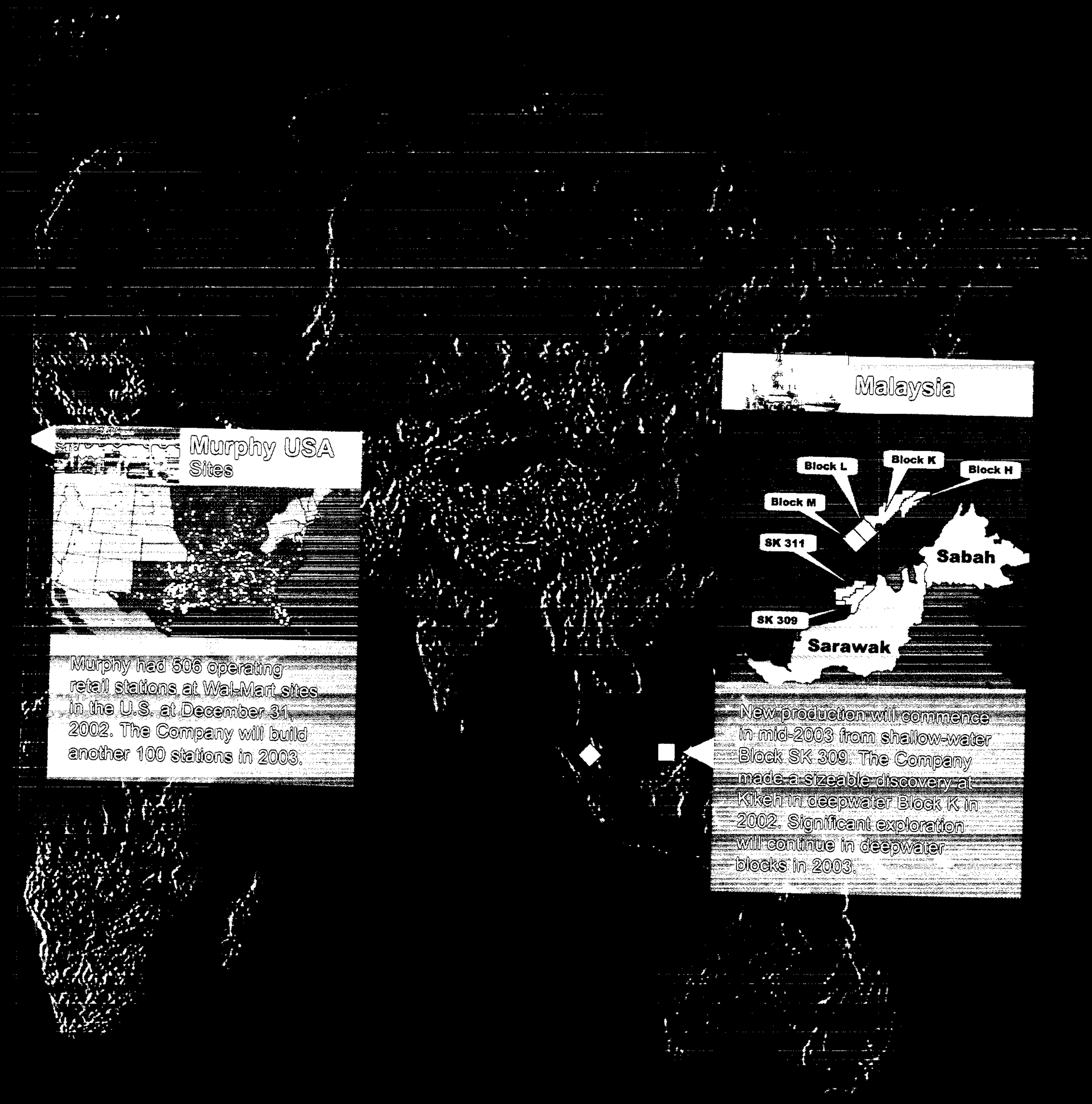
Claiborne P. Deming
President and Chief Executive Officer

February 19, 2003
El Dorado, Arkansas



In November 2002, Murphy opened its 500th Murphy USA retail fueling outlet in Houston, Texas.

Murphy has secured strategic worldwide positions for oil and gas exploration and production and downstream operations.

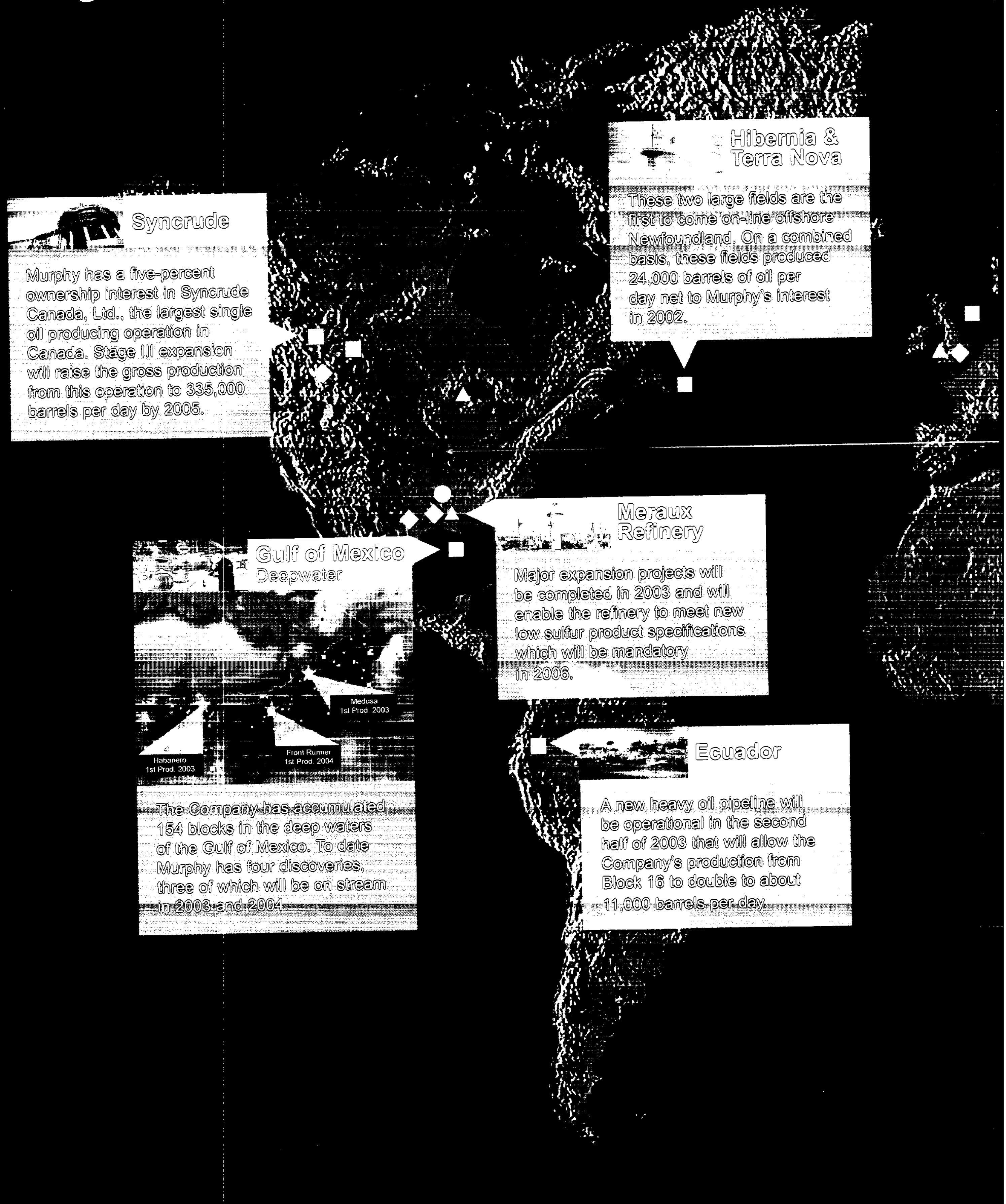


Key

■ Properties ● Headquarters

▲ Refineries ◆ Other Principal Offices

Murphy Oil Corporation
Major Properties



Exploration & Production

Murphy continues to generate significant production growth through its focused exploration programs in deepwater Gulf of Mexico, offshore eastern Canada, western Canada and Malaysia.

For the full year 2002, worldwide production averaged more than 125,800 barrels of oil equivalent a day, which reflected an increase of 10% over 2001 average levels, and continued Murphy's trend of achieving higher production levels each year for the last three years. Driving the increase was the start-up of production at the Terra Nova field offshore eastern Canada and peaking natural gas production rates at the Murphy-operated Ladyfern field in western Canada. The trend of increased production is set to continue in 2003, as two new fields in the deepwater Gulf of Mexico, Medusa and Habanero, come on stream and production in shallow-water Malaysia commences. Production rates during 2003 should reach an average of 130,000 to 135,000 barrels of oil equivalent a day. Operations during 2004 will benefit from a full year of Medusa, Habanero and shallow-water Malaysia production. Also in 2004, the Murphy-operated Front Runner field will be placed on stream, which should drive Murphy's average oil equivalent production on a worldwide basis above 160,000 barrels a day.

Murphy continues to generate significant production growth through its focused exploration programs

The deepwater Gulf of Mexico remains an integral component of

Exploration and Production

(thousands of dollars)	2002	2001	2000
Income from continuing operations	$ 161,003	187,543	245,755
Total assets	2,387,381	2,151,049	1,902,618
Capital expenditures	632,250	683,448	392,732
Crude oil and liquids produced – barrels a day	76,370	67,355	65,259
Natural gas sold – MCF a day	296,931	281,235	229,412
Net hydrocarbons produced – oil equivalent barrels a day	125,859	114,228	103,494
Net proved hydrocarbon reserves – thousands of oil equivalent barrels	455,300	501,200	442,300

Murphy's upstream strategy. Murphy moved to the deepwater in 1996 and to date has accumulated an acreage position of 154 blocks and has three major discoveries in development. Two of these developments, Medusa and Habanero, will be placed on stream during 2003. The first deepwater development is in the final stages at the Murphy-operated Medusa field in Mississippi Canyon Blocks 538 and 582 (60%) as the hull is on site and is expected to be mated with the topsides in early spring. The Medusa facility is sized to handle daily production rates of up to 40,000 barrels of oil and

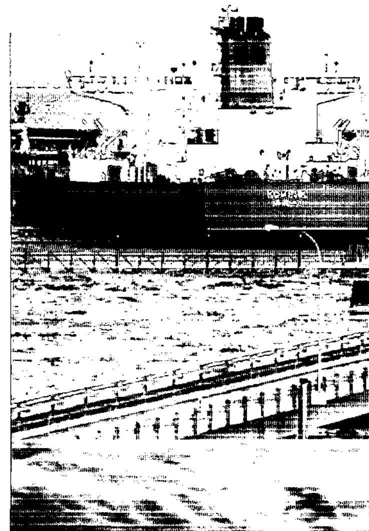
For 2002, worldwide production averaged 125,800 barrels of oil equivalent a day, an increase of 10% over 2001 average levels

110 million cubic feet of natural gas. First production is anticipated for mid-year 2003 and will ramp up throughout the remainder of the year.

The Habanero field, located in Garden Banks Block 341 (33.75%), is the other deepwater Gulf of Mexico development nearing completion and first production is expected during the third quarter of 2003 when two wells in this field will be tied into an existing host facility.

The Front Runner project, located in Green Canyon Blocks 338/339, was sanctioned in early 2002 with first production expected in 2004. The development plan includes a Truss Spar-type Floating Production System capable of handling daily production of 60,000 barrels of crude oil and 110 million cubic feet of natural gas and will serve as a production hub for Murphy-operated discoveries at Front Runner, Front Runner South and Quatrain (all 37.5%). Front Runner and Front Runner South were discovered during 2001. A smaller discovery was drilled at Quatrain during the third quarter of 2002. The well at Quatrain was cased as a producing well to tie into the spar facility being constructed for the Front Runner project. Located only one mile from the planned location of the Front Runner spar, Quatrain will be a cost effective tie back to that facility and reflects the maturity of Murphy's deepwater drilling program, whereby smaller discoveries can be economically produced through Company-owned and operated facilities.

Exploratory drilling will continue in the immediate Front Runner area, as Murphy plans to test at least two prospects during 2003 on the 13 contiguous blocks currently under lease by the Company. The first of which, Cool Papa, located in Green Canyon Block 380 (37.5%), is set to spud early in the second quarter of 2003. A wildcat well at the Lecomte



The oil tanker Kometik shuttles production from Murphy's Hibernia and Terra Nova fields with the latter field being the primary driver of the Company's production increase in 2002.

prospect, located in Green Canyon Block 428 (37.5%), is also planned for 2003. Murphy has identified several other prospects on this group of blocks and is planning further drilling in this region in 2004. In addition, a well will be drilled in the second quarter of 2003 to test a prospect named RunfortheRoses, located approximately 27 miles south of the Front Runner area in Green Canyon Blocks 735 and 736 (50%).

Off the east coast of Canada, the Terra Nova field (12%) was placed on stream in January 2002. Terra Nova produces through a state-of-the-art floating storage and production facility and serves as a strong complement to the nearby Hibernia field (6.5%). The production ramp-up from the Terra Nova field was outstanding and, based on high

...y has accumulated
...creage position in 154
...s in the deepwater
...of Mexico and has
...major discoveries
...velopment

volume testing of the facility, the operator has applied for increases in allowable throughputs. Similarly, Hibernia produced at record volumes in 2002 and is seeking increased allowable production rates. These East Coast assets were a primary driver of Murphy's strong production increases during 2002 and are on track for record volumes again in 2003.

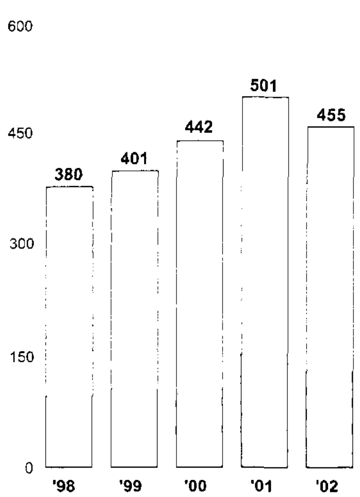
The results of Murphy's first three exploration wells on the Scotian Shelf, near Sable Island, were disappointing. In August 2002, Murphy and partners announced results from Annapolis (19%), the first industry deepwater well drilled off the Scotian Shelf. This well proved the existence of reservoir and hydrocarbon presence in a wildcat setting, but further drilling is required to establish threshold reserves for a commercial development. To this end, Murphy and partners are discussing additional exploratory drilling on the Annapolis block during 2003. Seismic surveys will also be acquired over the two adjacent blocks. This area has the potential to add North American natural gas reserves to Murphy's oil-weighted portfolio.

In western Canada, natural gas production reached record rates propelled by Murphy's operated interest in the prolific Ladyfern field (63%). The field reached peak gross production rates of over 700 million cubic feet a day as expected during the early summer of 2002 and is currently in decline. The Company continues to explore its large acreage position west of Ladyfern, and is also active with several winter wells in the foothills.

Murphy continues to be a player in the heavy oil and oil sands industry in Canada. An aggressive heavy oil drilling program began before year-end 2002, and will continue into 2003, focusing on primary and secondary recovery of conventional heavy oils in Murphy's traditional operating areas. Strong production growth from these properties is anticipated during 2003. Murphy is also an owner in Syncrude (5%), which has undertaken an aggressive expansion and will contribute growing volumes. The

Estimated Net Proved Hydrocarbon Reserves

(millions of oil equivalent barrels)



○ Ecuador and Other ○ United Kingdom
○ Canada ○ United States

Company believes it is important to continue to participate in the development of this vast Canadian resource, which offers a secure supply of hydrocarbons in North America for future decades.

The most significant story of 2002 on the exploration front lies in deepwater Malaysia. After a rocky beginning, with announced dry holes at the Bagang and Bliais prospects, Murphy achieved success at Kikeh (80%), the first deepwater oil discovery made in Malaysia. The initial Kikeh well in the southern part of Block K in 4,400 feet

An aggressive heavy oil drilling program in Canada will lead to strong production growth during 2003

of water found in excess of 500 net feet of oil pay and Murphy quickly moved to drill more wells to appraise the size of the structure. A total of three wells and two associated sidetracks have been drilled with an average net oil pay of 400 to 600 feet. Furthermore, all pay sands appeared to be in communication and were full to base with oil. To date, no water or natural gas has been found in any of the wells. During 2003, a different well location on the Kikeh structure will be drilled, then production tested, to help further define both reserves

and oil flow characteristics. Following those results, an engineering and design study will commence to determine the type of development needed with the aim of sanctioning a development project by year-end 2003 or early 2004. First production from deepwater Malaysia is expected by 2007.

Murphy will also test at least two new prospects on Block K this year and one on undrilled contiguous Block H to further explore Murphy's

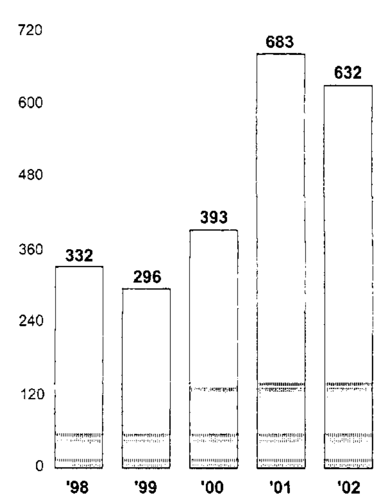
Murphy will test new prospects on Block K and Block H to further explore Murphy's large deepwater Malaysia acreage position

large deepwater Malaysia acreage position. Each of these prospects, if successful, have the potential to materially affect the reserves of the Company. Although exact drilling locations have not been named, drilling on Block K will likely be concentrated in the Kikeh vicinity searching for Kikeh "look-alikes," and on the southwest corner of Block H near exploratory success by another company in an adjacent block. Murphy, as operator, has an 80% working interest in Block K and adjoining Block H, which combined, cover over six million acres.

Success continues in Murphy's 85%-owned, shallow-water blocks in Malaysia. During 2002, Murphy confirmed the commercial viability of this acreage, by sanctioning a development at West Patricia, located approximately 25 miles from the coastal port of Bintulu, Sarawak, Malaysia. The establishment of a production center will allow Murphy to fully develop its surrounding acreage. Development at West Patricia is proceeding and the field is scheduled to be placed on stream during the second quarter of 2003. West Patricia will produce from a well jacket to a floating storage facility and will net to the Company approximately 10,000 barrels a day of oil at peak rates. West Patricia has been designed as a production hub

Capital Expenditures - Exploration and Production

(millions of dollars)



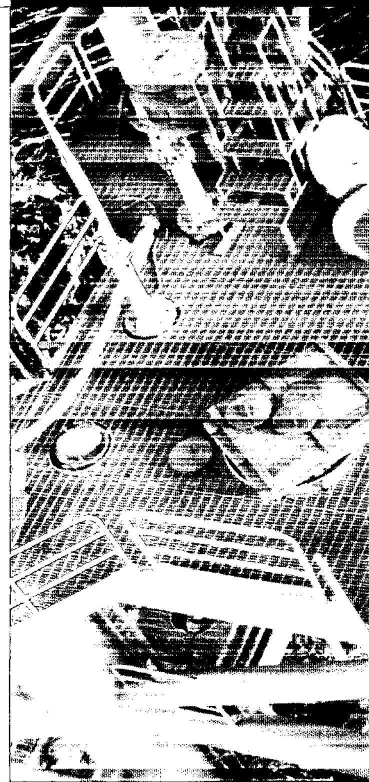
○ United Kingdom and Other
○ Malaysia ○ Canada ○ United States

and Murphy has identified many nearby untested structures that, if successful, could tie into the West Patricia infrastructure. In fact, Murphy has already had success at the nearby Congkak discovery. With the Congkak #1 exploration well, Murphy discovered a new oil field in Block SK 309, offshore Sarawak. The Congkak discovery is located in 136 feet of water and lies three kilometers

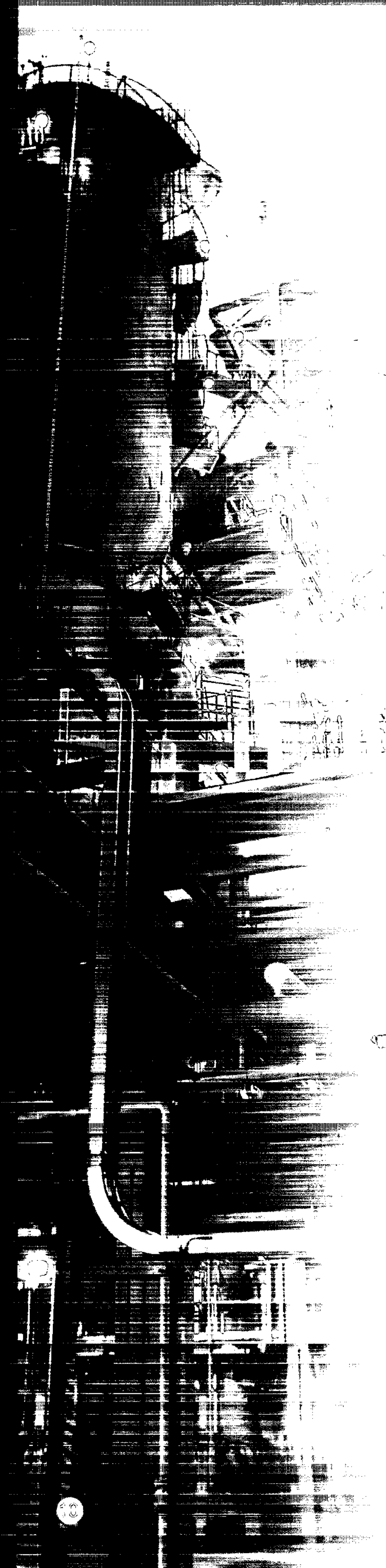
West Patricia is scheduled to be placed on stream during the second quarter of 2003 and will produce approximately 10,000 net barrels of oil a day at peak rates

from the West Patricia field production platform. The discovery supports Murphy's belief that there are many small field development opportunities on the acreage and the Company views Congkak as a natural add-on to its established infrastructure.

Murphy continues to extend its presence in Malaysia with the addition of an acreage position in Peninsular Malaysia and a new award of acreage in deepwater. A production sharing contract was signed in July 2002 giving Murphy a 75% working interest in PM Blocks 311/312. These blocks represent exploitation acreage, similar to shallow-water Blocks SK 309/311, as hydrocarbons have already been found on the blocks. Murphy plans to shoot 3D seismic surveys during 2003 in preparation for a drilling program that will commence in 2004.



Six development wells were drilled from this well jacket at West Patricia in preparation for first oil production in 2003.



In Murphy's downstream operations, refining and marketing margins in the U.S. and U.K. were squeezed during 2002 primarily due to generally rising crude oil prices throughout the year. Results were also hampered during the year by operational problems at the Meraux refinery that reduced the average daily crude oil throughput of this plant. The downstream business incurred a loss of almost $40 million in 2002 following a year of record operating earnings in 2001.

In late 2002, the Company opened its 500th Murphy USA station in Houston, Texas

The Murphy USA program continues to be the focus for the Company's downstream operation. In cooperation with Wal-Mart, Murphy builds high volume fueling sites in the parking lots of Wal-Mart Supercenters throughout the southern and midwestern United States. Through these outlets, Murphy provides gasoline and diesel to customers with convenient service and significant cost savings. Sales volumes at Murphy USA stations remain strong, averaging over 200,000 gallons a month per site. The Company opened its 500th location late in 2002 in Houston, Texas and by year-end had 506 sites in operation. These sites combine the benefits of low operating costs, low capital costs and high sales volume to create a formidable retail presence.

Of note in 2002, Murphy signed a new agreement with Wal-Mart to extend this program in Canada. Marketed under the Murphy Canada brand, six sites are currently open.

Due to the growth of the Murphy USA retail marketing business, the Company must buy a larger portion of gasoline needed to supply these stations. The size of this business has allowed the Company to achieve a stronger negotiating position for gasoline purchases in its marketing areas.

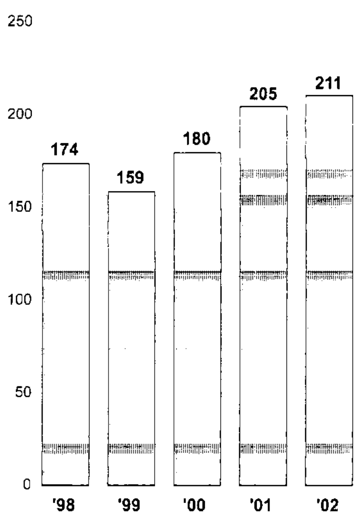
The expansion project at the Meraux refinery continued to proceed during

Refining and Marketing

(thousands of dollars)	*2002*	*2001*	*2000*
Income (loss)	$ (39,908)	153,680	54,456
Total assets	1,208,244	918,764	1,018,555
Capital expenditures	234,714	175,186	153,750
Crude oil processed – barrels a day	143,829	167,199	165,820
Products sold – barrels a day	210,631	205,318	179,515

Refined Products Sold

(thousands of barrels a day)



○ United Kingdom ○ North America

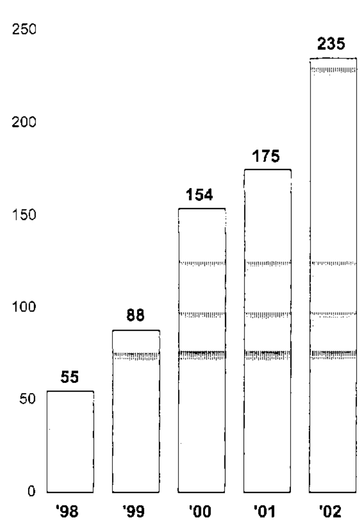
2002. Murphy is constructing a hydrocracker and related hardware that, when installed, will allow Murphy to produce low-sulfur gasoline and diesel products ahead of mandated requirements. The Company is also expanding the refinery's crude processing capacity from 100,000 to 125,000 barrels a day. The start-up of the hydrocracker and expanded crude unit is expected to take place during the third quarter of 2003. Once this green fuels project is completed, capital expenditures in the Company's downstream business will sharply drop.

Murphy also owns a refinery at Superior, Wisconsin, on the western tip of Lake Superior. This refinery can process 35,000 barrels per day of Canadian and domestic crude oil, with its primary attribute being the ability to produce asphalt products from generally lower-priced Canadian heavy oil that is available to the refinery via pipeline. Superior's lighter refined products also serve to supply the Company's stations at Wal-Mart stores in the upper Midwest.

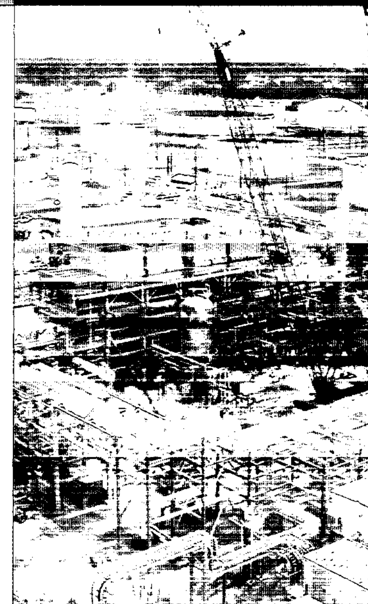
Murphy has an effective 30% interest in a refinery at Milford Haven, Wales, where up to 32,400 barrels of crude oil per day can be processed for the Company's account. The Company markets light refined products to U.K. retail customers primarily under the Murco brand. Murphy's U.K. downstream business continues to benefit from a successful alliance with the Costcutter grocery chain, which upgrades neighborhood motor fueling stations into popular and convenient shopping destinations for local consumers.

Capital Expenditures - Refining and Marketing

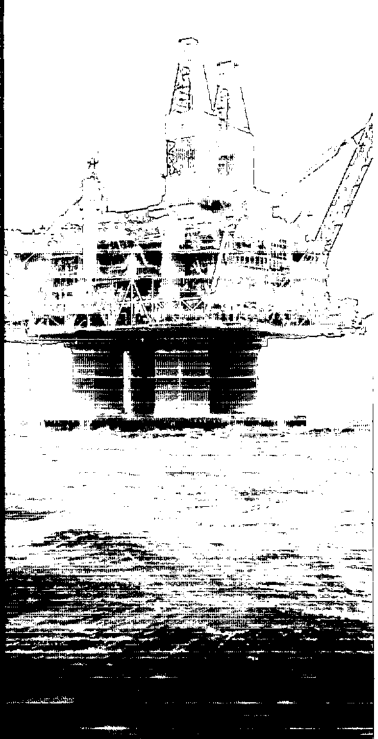
(millions of dollars)



○ United Kingdom ○ North America



The Meraux refinery's clean fuels project includes the addition of a hydrocracker unit, which will help Murphy provide "greener" fuels to consumers.



Murphy has substantially increased its production profile and added value to the Company by meticulously concentrating on what it does best - adding reserves through the drill bit.

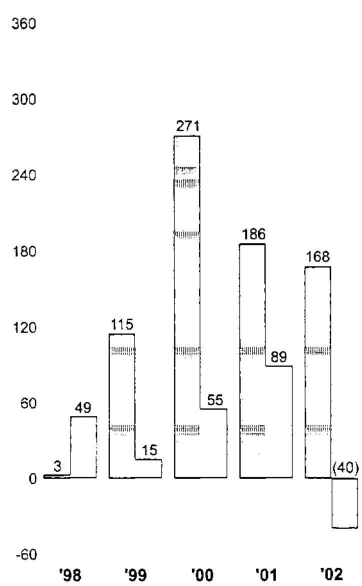
As a mid-size player in the energy industry, Murphy realizes it must deploy resources in a focused, deliberate manner. To this end, Murphy concentrates its exploration capital in four main areas: deepwater Gulf of Mexico, western Canada, the Scotian Shelf offshore eastern Canada, and Malaysia. To date, Murphy has announced significant discoveries in three of its core areas through success at Medusa and Front Runner in the deepwater Gulf, the Ladyfern natural gas field in western Canada and Kikeh in deepwater Malaysia.

Murphy has substantially increased its production profile and added value to the Company by meticulously concentrating on what it does best - adding reserves through the drill bit. In downstream operations, Murphy has a retail presence through its relationship with Wal-Mart that is unparalleled in the industry. The combination of its acreage portfolio, aggressive exploration program, and downstream retail strategy position Murphy as an outperformer not only capable of continuing its successful track record, but ready to climb to a new level of growth and profitability.

Income Contribution from Continuing Operations by Function

(millions of dollars)

Excludes nonrecurring items and Corporate activities

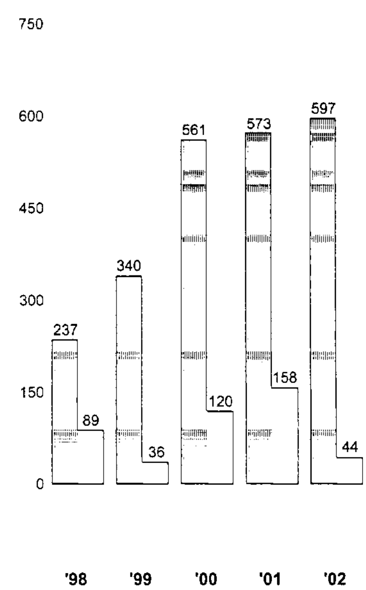


○ Refining and Marketing
○ Exploration and Production

Cash Flow from Continuing Operations by Function

(millions of dollars)

Excludes nonrecurring items, Corporate activities and changes in noncash working capital



○ Refining and Marketing
○ Exploration and Production

Statistical Summary

	2002	2001	2000	1999	1998
Exploration and Production					
Net crude oil and condensate production – barrels a day					
United States	**3,837**	4,339	4,770	5,826	5,192
Canada – light	**2,150**	2,937	2,606	2,992	3,219
heavy	**9,484**	11,707	10,574	9,099	9,676
offshore	**24,037**	9,535	9,199	6,404	4,192
synthetic	**11,362**	10,479	8,443	10,997	10,500
United Kingdom	**18,180**	20,049	20,679	20,217	14,975
Ecuador	**4,544**	5,319	6,405	7,104	7,720
Net natural gas liquids production – barrels a day					
United States	**291**	413	551	777	643
Canada	**1,206**	1,401	474	488	612
United Kingdom	**122**	165	216	321	436
Continuing operations	**75,213**	66,344	63,917	64,225	57,165
Discontinued operations	**1,157**	1,011	1,342	1,858	1,963
Total liquids produced	**76,370**	67,355	65,259	66,083	59,128
Net crude oil and condensate sold – barrels a day					
United States	**3,837**	4,339	4,769	5,832	5,185
Canada – light	**2,150**	2,937	2,606	2,992	3,219
heavy	**9,484**	11,707	10,574	9,099	9,676
offshore	**23,935**	9,862	9,456	4,727	4,396
synthetic	**11,362**	10,479	8,443	10,997	10,500
United Kingdom	**18,209**	20,206	20,921	20,217	15,336
Ecuador	**4,293**	5,381	6,393	7,104	7,907
Net natural gas liquids sold – barrels a day					
United States	**291**	413	551	777	643
Canada	**1,206**	1,401	474	488	612
United Kingdom	**149**	148	216	321	436
Continuing operations	**74,916**	66,873	64,403	62,554	57,910
Discontinued operations	**1,157**	1,011	1,342	1,858	1,963
Total liquids sold	**76,073**	67,884	65,745	64,412	59,873
Net natural gas sold – thousands of cubic feet a day					
United States	**88,067**	112,616	141,373	163,587	160,932
Canada	**197,852**	152,583	73,773	56,238	48,998
United Kingdom	**6,973**	13,125	10,850	12,443	12,384
Continuing operations	**292,892**	278,324	225,996	232,268	222,314
Discontinued operations	**4,039**	2,911	3,416	8,175	8,587
Total natural gas sold	**296,931**	281,235	229,412	240,443	230,901
Net hydrocarbons produced – equivalent barrels[1,2] a day	**125,859**	114,228	103,494	106,157	97,612
Estimated net hydrocarbon reserves – million equivalent barrels[1,2,3]	**455.3**	501.2	442.3	400.8	379.9
Weighted average sales prices[4]					
Crude oil and condensate – dollars a barrel					
United States	**$ 24.25**	24.92	30.38	18.09	12.89
Canada[5] – light	**22.60**	22.40	27.68	17.00	12.03
heavy	**16.82**	11.06	17.83	12.77	6.56
offshore	**25.36**	23.77	27.16	19.08	11.80
synthetic	**25.64**	25.04	29.62	18.64	13.73
United Kingdom	**24.39**	24.44	27.78	18.09	12.52
Ecuador	**19.64**	17.00	22.01	14.42	8.56
Natural gas liquids – dollars a barrel					
United States	**17.13**	20.40	23.04	13.70	11.50
Canada[5]	**16.35**	20.35	19.98	12.09	9.16
United Kingdom	**18.28**	19.12	23.64	13.45	11.04
Natural gas – dollars a thousand cubic feet					
United States	**3.37**	4.64	4.01	2.34	2.25
Canada[5]	**2.74**	3.28	3.67	1.96	1.40
United Kingdom[5]	**2.76**	2.52	1.81	1.68	2.23

[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.

Statistical Summary

	2002	2001	2000	1999	1998
Refining					
Crude capacity[1] of refineries – barrels per stream day	**167,400**	167,400	167,400	167,400	167,400
Refinery inputs – barrels a day					
Crude – Meraux, Louisiana	**83,721**	104,345	103,154	82,410	101,834
Superior, Wisconsin	**30,468**	35,869	34,159	33,402	32,966
Milford Haven, Wales	**29,640**	26,985	28,507	27,392	30,780
Other feedstocks	**11,013**	9,901	8,298	10,484	11,404
Total inputs	**154,842**	177,100	174,118	153,688	176,984
Refinery yields – barrels a day					
Gasoline	**63,409**	73,217	75,106	65,216	73,482
Kerosine	**9,446**	12,874	11,955	11,316	15,394
Diesel and home heating oils	**48,344**	52,660	49,606	44,054	50,506
Residuals	**16,589**	20,530	18,524	17,370	21,310
Asphalt, LPG and other	**12,651**	13,467	14,624	12,225	12,565
Fuel and loss	**4,403**	4,352	4,303	3,507	3,727
Total yields	**154,842**	177,100	174,118	153,688	176,984
Average cost of crude inputs to refineries – dollars a barrel					
North America	**$ 24.76**	23.44	28.82	18.80	12.55
United Kingdom	**25.83**	24.86	29.29	17.22	13.62
Marketing					
Products sold – barrels a day					
North America – Gasoline	**112,281**	96,597	76,314	61,786	61,429
Kerosine	**5,818**	9,621	8,517	7,545	10,170
Diesel and home heating oils	**35,995**	41,064	39,347	34,514	40,403
Residuals	**13,759**	17,308	15,163	13,812	16,170
Asphalt, LPG and other	**8,574**	9,666	10,271	9,134	9,887
	176,427	174,256	149,612	126,791	138,059
United Kingdom – Gasoline	**12,058**	11,058	11,622	12,511	14,058
Kerosine	**2,685**	2,547	2,478	3,053	4,369
Diesel and home heating oils	**14,574**	11,798	9,760	10,995	10,884
Residuals	**3,127**	3,538	3,852	3,608	5,203
LPG and other	**1,760**	2,121	2,191	2,084	1,579
	34,204	31,062	29,903	32,251	36,093
Total products sold	**210,631**	205,318	179,515	159,042	174,152
Branded retail outlets[1]					
North America	**914**	815	712	625	552
United Kingdom	**416**	411	386	384	389
Stockholder and Employee Data					
Common shares outstanding[1,2] (thousands)	**91,689**	90,662	90,092	89,996	89,900
Number of stockholders of record[1]	**2,826**	2,991	3,185	3,431	3,684
Number of employees[1]	**4,010**	3,779	3,109	2,153	1,566
Average number of employees	**3,875**	3,438	2,528	1,797	1,498

[1]At December 31.

[2]1998 through 2001 have been adjusted to reflect a two-for-one stock split effective December 30, 2002.

Directors

William C. Nolan Jr. [1]
Chairman of the Board
Murphy Oil Corporation
Partner
Nolan and Alderson
El Dorado, Arkansas
Director since 1977

Claiborne P. Deming [1]
President and Chief Executive Officer
Murphy Oil Corporation
El Dorado, Arkansas
Director since 1993

Frank W. Blue [2,4]
Attorney
Fulbright & Jaworski
Houston, Texas
Director since 2003

George S. Dembroski [1,2,3]
Vice Chairman, Retired
RBC Dominion Securities Limited
Toronto, Ontario, Canada
Director since 1995

H. Rodes Hart [2,3]
Chairman and Chief Executive Officer
Franklin Industries, Inc.
Nashville, Tennessee
Director since 1975

Robert A. Hermes [4,5]
Chairman of the Board
Purvin & Gertz, Inc.
Houston, Texas
Director since 1999

Michael W. Murphy
President
Marmik Oil Company
El Dorado, Arkansas
Director since 1977

R. Madison Murphy [1,2]
Private Investor
El Dorado, Arkansas
Director since 1993

Ivar B. Ramberg [4,5]
Executive Officer
Ramberg Consulting AS (Ram-Co)
Lysaker, Norway
Director since 2003

David J. H. Smith [3,5]
Chief Executive Officer, Retired
Whatman plc
Maidstone, Kent, England
Director since 2001

Caroline G. Theus [1,5]
President
Keller Enterprises, LLC
Alexandria, Louisiana
Director since 1985

Committees of the Board

1 Member of the Executive Committee chaired by Mr. Nolan. The Chairman serves as ex-officio member of all Committees.

2 Member of the Audit Committee chaired by Mr. R. Madison Murphy.

3 Member of the Executive Compensation Committee chaired by Mr. Dembroski.

4 Member of the Nominating and Governance Committee chaired by Mr. Hermes.

5 Member of the Public Policy and Environmental Committee chaired by Mrs. Theus.

Executive Officers

Claiborne P. Deming
President and Chief Executive Officer

W. Michael Hulse
Executive Vice President – Worldwide Downstream Operations

Steven A. Cossé
Senior Vice President and General Counsel

Bill H. Stobaugh
Vice President

Kevin G. Fitzgerald
Treasurer

John W. Eckart
Controller

Walter K. Compton
Secretary

Director Emeritus

William C. Nolan

Principal Subsidiaries

Murphy Exploration & Production Company - USA

131 South Robertson Street
New Orleans, Louisiana 70112
(504) 561-2811

Mailing Address:
P. O. Box 61780
New Orleans, Louisiana 70161-1780

Engaged in crude oil and natural gas exploration and production in the continental U.S. and in the Gulf of Mexico.

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.

2100–555–4th Avenue S.W.
Calgary, Alberta T2P 3E7
(403) 294-8000

Mailing Address:
P. O. Box 2721, Station M
Calgary, Alberta T2P 3Y3
Canada

Engaged in crude oil and natural gas exploration and production, extraction and sale of synthetic crude oil, and marketing of petroleum products in Canada.

Harvey Doerr
President

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

550 WestLake Park Blvd.
Suite 1000
Houston, Texas 77079
(281) 249-1040

Engaged in crude oil and natural gas exploration and production outside North America and in Alaska.

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

John W. Eckart
Controller

Walter K. Compton
Secretary

Murphy Oil USA, Inc.

200 Peach Street
El Dorado, Arkansas 71730
(870) 862-6411

Mailing Address:
P. O. Box 7000
El Dorado, Arkansas 71731-7000

Engaged in refining and marketing of petroleum products in the United States.

W. Michael Hulse
President

Charles A. Ganus
Senior Vice President, Marketing

Frederec C. Green
Senior Vice President, Engineering and Government Affairs

Gary R. Bates
Vice President, Supply and Transportation

Henry J. Heithaus
Vice President, Retail Marketing

Ernest C. Cagle
Vice President, Manufacturing

Steven A. Cossé
Vice President and General Counsel

Gordon W. Williamson
Treasurer

John W. Eckart
Controller

Walter K. Compton
Secretary

Murphy Eastern Oil Company

4 Beaconsfield Road
St. Albans, Hertfordshire
AL1 3RH, England
172-789-2400

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 United Kingdom.

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, 2002**

OR

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

For the transition period from ____________________ to ____________________

Commission file number **1-8590**

MURPHY OIL CORPORATION

(Exact name of registrant as specified in its charter)

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

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, 2003, as quoted by the New York Stock Exchange, was approximately $2,924,876,000.

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 28, 2002, as quoted by the New York Stock Exchange, was approximately $2,894,828,000.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2003 was 91,699,376.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 14, 2003 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. Canadian pipeline and trucking operations were sold in May 2001. Additionally, "Corporate and Other Activities" include interest income, interest expense and overhead not allocated to the segments.

The information appearing in the 2002 Annual Report to Security Holders (2002 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 8 through 17, F-13, F-29 through F-31, F-35 through F-37, and F-39 of this Form 10-K report and on pages 4 through 12 of the 2002 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

During 2002, Murphy's principal exploration and production activities were conducted in the United States, Ecuador and Malaysia by wholly owned Murphy Exploration & Production Company (Murphy Expro) 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 2002 was in the United States, Canada, the United Kingdom and Ecuador; its natural gas was produced and sold in the United States, Canada and the United Kingdom. MOCL owns a 5% interest in Syncrude Canada Ltd., which utilizes its assets to extract bitumen from oil sand deposits in northern Alberta and to upgrade this bitumen into synthetic crude oil.

Murphy's estimated net quantities of proved oil and gas reserves and proved developed oil and gas reserves at December 31, 1999, 2000, 2001 and 2002 by geographic area are reported on pages F-33 and F-34 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, 2002 are shown on page 13 of the 2002 Annual Report.

Production expenses for the last three years in U.S. dollars per equivalent barrel are discussed on page 14 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-32 through F-39 of this Form 10-K report.

At December 31, 2002, 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)	Gross	Net	Gross	Net	Gross	Net
United States – Onshore	18	7	32	20	50	27
– Gulf of Mexico	20	6	1,139	722	1,159	728
– Frontier	8	*	64	13	72	13
Total United States	46	13	1,235	755	1,281	768
Canada – Onshore	851	292	1,263	868	2,114	1,160
– Offshore	88	7	12,129	2,040	12,217	2,047
Total Canada	939	299	13,392	2,908	14,331	3,207
United Kingdom	78	11	717	201	795	212
Ecuador	7	1	524	105	531	106
Malaysia	–	–	11,498	9,192	11,498	9,192
Ireland	–	–	650	98	650	98
Spain	–	–	36	6	36	6
Totals	1,070	324	28,052	13,265	29,122	13,589
Oil sands in Canada	95	5	158	8	253	13

*less than one.

The only significant undeveloped acreage that expires in the next three years is approximately 2.4 million acres in shallow-water Blocks SK 309 and SK 311 in Malaysia that is not included in the West Patricia 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, 2002.

Country	Oil Wells Gross	Oil Wells Net	Gas Wells Gross	Gas Wells Net
United States	184	62	142	51
Canada	2,914	573	836	386
United Kingdom	103	12	22	2
Ecuador	72	14	–	–
Totals	3,273	661	1,000	439
Wells included above with multiple completions and counted as one well each	30	16	30	18

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

	United States		Canada		United Kingdom		Ecuador		Malaysia and Other		Total	
	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry
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
2000												
Exploratory	2.0	3.9	6.4	12.0	.1	.3	–	–	.8	–	9.3	16.2
Development	.3	–	51.7	4.0	.6	.1	1.0	–	–	–	53.6	4.1

Murphy's drilling wells in progress at December 31, 2002 are shown below.

Country	Exploratory Gross	Exploratory Net	Development Gross	Development Net	Total Gross	Total Net
United States	1	*	2	.9	3	.9
Canada	5	1.9	4	1.0	9	2.9
United Kingdom	–	–	9	.7	9	.7
Malaysia	–	–	2	1.7	2	1.7
Totals	6	1.9	17	4.3	23	6.2

*less than 0.1.

Additional information about current exploration and production activities is reported on pages 4 through 9 of the 2002 Annual Report.

Refining and Marketing

Murphy Oil USA, Inc. (MOUSA), a wholly owned subsidiary, 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 a day. Refinery capacities at December 31, 2002 are shown in the following table.

	Meraux, Louisiana	Superior, Wisconsin	Milford Haven, Wales (Murco's 30%)	Total
Crude capacity – b/sd*	100,000	35,000	32,400	167,400
Process capacity – b/sd*				
Vacuum distillation	50,000	20,500	16,500	87,000
Catalytic cracking – fresh feed	38,000	11,000	9,960	58,960
Naphtha hydrotreating	22,000	9,000	5,490	36,490
Catalytic reforming	18,000	8,000	5,490	31,490
Distillate hydrotreating	15,000	7,800	20,250	43,050
Gas oil hydrotreating	27,500	–	–	27,500
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 is in the process of expanding the Meraux refinery, with the expansion scheduled to be completed and operational by the fourth quarter 2003. The expansion will allow the refinery to meet new low-sulfur product specifications which become effective in 2006. The expansion includes a new hydrocracker unit, central control room and two new utility boilers; expansion of the crude oil processing capacity from 100,000 barrels per stream day (b/sd) to 125,000 b/sd, expansion of naphtha hydrotreating capacity from 22,000 b/sd to 35,000 b/sd, and expansion of the catalytic reforming capacity from 18,000 b/sd to 32,000 b/sd; and construction of a new sulfur recovery complex, including amine regeneration, sour water stripping and high efficiency sulfur recovery.

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 11 terminals that are wholly owned and operated by MOUSA, 16 terminals that are jointly owned and operated by others, and numerous terminals owned by others. Of the terminals wholly owned or jointly owned, four are supplied by marine transportation, three are supplied by truck, two are adjacent to MOUSA's refineries and 18 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. At December 31, 2002, the Company marketed products through 506 Murphy USA stations and 402 branded wholesale SPUR stations. MOUSA plans to add about 100 new Murphy USA stations at Wal-Mart sites in the southern and midwestern United States in 2003. In February 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 six stations at Wal-Mart sites in Canada at December 31, 2002. An additional seven Murphy Canada stations are expected to be added in 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 each 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 30.3% of total Company revenues in 2002, 22.5% in 2001 and 14.6% in 2000. 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 2002, 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 416 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, 2002 are reported on pages 10, 11 and 14 of the 2002 Annual Report.

Employees

At December 31, 2002, Murphy had 4,010 employees – 1,980 full-time and 2,030 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 22 of this Form 10-K report.

In 2002, the Company's production of oil and natural gas represented approximately 0.1% of the respective worldwide totals. Murphy owned approximately 0.8% of the crude oil refining capacity in the United States and its market share of U.S. retail gasoline sales was approximately 0.8%.

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, 2002, 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, 2003, 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 48; 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.

W. Michael Hulse – Age 49; 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.

Steven A. Cossé – Age 55; 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.

Bill H. Stobaugh – Age 51; 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 47; 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 44; Controller since March 2000. Mr. Eckart had been Assistant Controller since February 1995. He joined the Company as Auditing Manager in 1990.

Walter K. Compton – Age 40; Secretary since December 1996. He has been an attorney with the Company since 1988 and became Manager, Law Department, in November 1996.

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$4.61 billion. The Company believes that the counterclaim is without merit and that the amount of damages sought is frivolous. While the litigation is in its preliminary stages 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.

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. The ultimate resolution of matters referred to in this item could have a material adverse effect on the Company's earnings 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 2002.

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 and the Toronto Stock Exchange using "MUR" as the trading symbol. There were 2,826 stockholders of record as of December 31, 2002. Information as to high and low market prices per share and dividends per share by quarter for 2002 and 2001 are reported on page F-40 of this Form 10-K report.

Item 6. SELECTED FINANCIAL DATA

(Thousands of dollars except per share data)	2002	2001	2000	1999	1998
Results of Operations for the Year[1]					
Sales and other operating revenues[2]	$ 3,966,516	3,743,986	3,630,195	2,076,103	1,718,110
Net cash provided by continuing operations	526,969	630,631	738,083	332,455	290,526
Income (loss) from continuing operations	97,510	328,430	298,526	113,980	(17,317)
Net income (loss)	111,508	330,903	296,828	119,707	(14,394)
Per Common share – diluted[3]					
Income (loss) from continuing operations	1.06	3.60	3.30	1.27	(.19)
Net income (loss)	1.21	3.63	3.28	1.33	(.16)
Cash dividends per Common share[3]	.775	.75	.725	.70	.70
Percentage return on					
Average stockholders' equity	7.3	23.5	26.4	12.3	(1.3)
Average borrowed and invested capital	5.8	17.7	20.3	9.7	(.6)
Average total assets	3.9	10.2	11.2	5.2	(.6)
Capital Expenditures for the Year					
Continuing operations					
Exploration and production	$ 631,799	680,100	392,732	295,906	330,842
Refining and marketing	234,714	175,186	153,750	88,075	55,025
Corporate and other	1,136	5,806	11,415	2,572	2,127
	867,649	861,092	557,897	386,553	387,994
Discontinued operations	451	3,348	–	52	805
	$ 868,100	864,440	557,897	386,605	388,799
Financial Condition at December 31					
Current ratio	1.19	1.07	1.10	1.22	1.15
Working capital	$ 136,268	38,604	71,710	105,477	56,616
Net property, plant and equipment	2,886,599	2,525,807	2,184,719	1,782,741	1,662,362
Total assets	3,885,775	3,259,099	3,134,353	2,445,508	2,164,419
Long-term debt	862,808	520,785	524,759	393,164	333,473
Stockholders' equity	1,593,553	1,498,163	1,259,560	1,057,172	978,233
Per share[3]	17.38	16.53	13.98	11.75	10.88
Long-term debt – percent of capital employed	35.1	25.8	29.4	27.1	25.4

[1]Includes effects on income of nonrecurring items in 2002, 2001 and 2000 that are detailed in Management's Discussion and Analysis of Financial Condition and Results of Operations. Also, nonrecurring items in 1999 and 1998 increased (decreased) net income (loss) by $19,753, $.22 per diluted share, and $(57,935), $(.64) per diluted share, respectively.

[2]Amounts for 1998 to 2001 have been restated to reflect the adoption of EITF Issue 02-3. See page 19 of this Form 10-K for further information.

[3]Per Common share amounts for 1998 to 2001 have been adjusted to reflect a two-for-one stock split effective December 30, 2002.

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

Results of Operations

The Company reported net income in 2002 of $111.5 million, $1.21 per diluted share, compared to net income in 2001 of $330.9 million, $3.63 per share. In 2000 the Company earned $296.8 million, $3.28 per diluted share. All 2001 and 2000 earnings per share have been adjusted to reflect the two-for-one stock split effective December 30, 2002. In December 2002 the Company sold its interest in Ship Shoal Block 113 in the Gulf of Mexico for an after-tax gain of $10.6 million. In accordance with Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which the Company adopted on January 1, 2002, the results of operations for Ship Shoal Block 113 have been reflected as discontinued operations in all years presented. Therefore, the aforementioned gain on disposal of $10.6 million in 2002, and routine operating results of the field, have been included net of income tax expense as Discontinued Operations in the consolidated statements of income for the three years ended December 31, 2002. Income from continuing operations was $97.5 million in 2002, $1.06 per share; $328.4 million in 2001, $3.60 per share; and $298.5 million in 2000, $3.30 per share.

The three year period ended December 31, 2002 included certain nonrecurring items which can obscure underlying trends of operating results and affect comparability between years. Although results excluding nonrecurring items is considered a non-GAAP measure, the Company's management believes this information is useful in assessing Murphy Oil's performance. Nonrecurring items reduced income from continuing operations in 2002 by $6.7 million, but increased this amount by $67.6 million in 2001 and $1.5 million in 2000. Excluding these nonrecurring items, income from continuing operations amounted to $104.2 million in 2002, $260.8 million in 2001, and $297 million in 2000. In 2000 the Company recorded a net charge of $8.7 million, $.10 per share, as the cumulative effect of an accounting change for a one-time non-cash adjustment to record crude oil revenues at the time the oil is sold rather than as it is produced.

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. The decline in 2002 results 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 $74.3 million reduction in income from nonrecurring items in 2002. The lower income from nonrecurring items was primarily caused by 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 record levels of oil and natural gas production and higher average oil 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 record production and sales of crude oil and 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 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 record 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 marketing 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, Louisiana refinery. Income tax expense fell by $119.5 million essentially in line with lower pretax income from continuing operations.

2001 vs. 2000 – Income from continuing operations in 2001 was a company record $328.4 million, $3.60 per share, an increase of $29.9 million from the $298.5 million, $3.30 per share, earned in 2000. Record earnings in 2001 from the Company's refining and marketing operations and greater benefits from nonrecurring items were only partially offset by lower income from exploration and production activities. Improved refining and marketing results of $99.2 million were attributable to stronger unit margins in the U.S. refining business during the first half of 2001 and a $71 million nonrecurring profit on sale of Canadian pipeline and trucking operations in May 2001. Exploration and production results declined by $58.2 million in 2001 mainly caused by an 18% reduction in realized oil prices and higher exploration expenses. These were partially offset by higher oil and natural gas production and lower charges for property impairments.

Sales and other operating revenues in 2001 increased by $113.8 million compared to 2000 due to higher oil, natural gas and refined product sales volumes. Gain on sale of assets was up by $101.5 million due to the sale in May 2001 of the Canadian pipeline and trucking operations. Interest and other income was $7.5 million lower in 2001 due to less interest earned on invested cash balances and lower interest associated with settlement of prior year tax issues. Crude oil, natural gas and product purchases were $46 million higher due to more purchases of crude oil and refined products, with this effort partially mitigated by a lower average price than in 2000. Operating expenses increased by $66.5 million due to higher oil and natural gas production and more retail gasoline stations. The increase of $31.3 million in exploration expenses is explained on page 14. Selling and general expenses increased by $12.4 million primarily due to higher salaries and benefits and legal and professional fees in 2001. Depreciation, depletion and amortization expense rose by $15.7 million due to a combination of higher oil and gas production and more retail marketing stations. Amortization of goodwill of $3.1 million related to the acquisition of Beau Canada Exploration Ltd. (Beau Canada) in

November 2001. Impairment of properties was down by $17.4 million in 2001 due to less impairment write-downs for Gulf of Mexico and western Canada properties. Interest expense was $9.4 million higher in 2001 due to higher average borrowings during the year, primarily arising from the acquisition of Beau Canada in late 2000. Capitalized interest was $6.7 million more than in 2000 primarily due to continued development expenditures for the Terra Nova field, offshore Newfoundland. Income tax expense increased by $17.7 million in 2001 due to higher pretax earnings from continuing operations.

In the following table, the Company's results of operations for the three years ended December 31, 2002 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)	2002	2001	2000
Exploration and production			
United States	$ (11.8)	55.3	43.3
Canada	157.0	85.5	108.1
United Kingdom	49.6	78.6	90.2
Ecuador	12.0	11.5	21.1
Malaysia	(43.0)	(36.1)	(10.7)
Other	(2.8)	(7.3)	(6.3)
	161.0	187.5	245.7
Refining and marketing			
North America	(39.2)	139.6	31.5
United Kingdom	(.7)	14.1	23.0
	(39.9)	153.7	54.5
Corporate and other	(23.6)	(12.8)	(1.7)
Income from continuing operations	97.5	328.4	298.5
Discontinued operations	14.0	2.5	7.0
Income before cumulative effect of accounting change	111.5	330.9	305.5
Cumulative effect of accounting change	–	–	(8.7)
Net income	$ 111.5	330.9	296.8

Nonrecurring Items – Income from continuing operations in the table above includes the following nonrecurring items, which can affect underlying trends of operating results and comparability between years. These nonrecurring items are presented net of tax below and are discussed in more detail following the tables.

(Millions of dollars)	2002	2001	2000
Gain on sale of assets	$ 2.3	71.0	1.5
Tax settlements and tax rate change	14.7	8.9	25.6
Impairment of properties	(20.5)	(6.8)	(17.8)
Cost to repair storm damages	(3.2)	–	–
Provision for U.S. environmental matters	–	(5.5)	–
Loss on transportation and other disputed contractual items in Ecuador	–	–	(7.8)
Income (loss) from nonrecurring items	$ (6.7)	67.6	1.5

These nonrecurring items were reflected in the following segments.

(Millions of dollars)	2002	2001	2000
Exploration and production			
United States	$ (6.7)	(5.8)	(13.6)
Canada	–	5.8	(4.2)
United Kingdom	–	1.9	–
Ecuador	–	–	(7.8)
	(6.7)	1.9	(25.6)
Refining and marketing			
North America	–	64.7	–
	–	64.7	–
Corporate and other	–	1.0	27.1
Income (loss) from nonrecurring items	$ (6.7)	67.6	1.5

- *Gain on sale of assets* – An after-tax gain of $2.3 million was recorded in the third quarter 2002 associated with the sale of assets. After-tax gains of $67.6 million and $3.4 million were recorded in the second and fourth quarter, respectively, of 2001 for the sale of Canadian pipeline and trucking assets. After-tax gains of $1.5 million were recorded in the second quarter of 2000 from the sale of U.S. corporate assets.

- *Tax settlements and tax rate change* – Income of $14.7 million was recorded in the third quarter 2002 from settlement of prior year tax matters. Income of $5.5 million was recorded in the third quarter of 2001 from a reduction in a Canadian provincial tax rate. In addition, settlement of income tax matters in the U.S. and U.K. provided income of $3.4 million in the fourth quarter of 2001. Income of $15.5 million and $10.1 million from settlement of U.S. income tax matters was recorded in the third quarter of 2000 and the fourth quarter of 2000, respectively.

- *Impairment of properties* – An after-tax charge of $14.6 million was recorded in the fourth quarter of 2002 to write-off the remaining cost in Destin Dome Blocks 56 and 57, offshore Florida. An agreement with the U.S. government restricts the Company's ability to seek approval for development of this significant natural gas discovery until at least 2012. Additionally, after-tax charges of $5.9 million, $6.8 million, $13.6 million and $4.2 million were recorded in the third quarter of 2002, the fourth quarter of 2001, the third quarter of 2000 and the fourth quarter of 2000, respectively, for the write-down of assets determined to be impaired. (See Note E to the consolidated financial statements.)

- *Cost to repair storm damages* – An after-tax charge of $3.2 million was recorded in the third quarter of 2002 for costs to repair uninsured equipment damages caused by tropical storms in the Gulf of Mexico.

- *Provision for U.S. environmental matters* – A $5.5 million charge was recorded in the third quarter of 2001 to resolve Clean Air Act violations at the Company's Superior, Wisconsin refinery.

- *Loss on transportation and other disputed contractual items in Ecuador* – A loss of $7.8 million was recorded in the fourth quarter of 2000, which included a $4.3 million expense related to prior years' transportation costs, a charge of $3.2 million to establish an allowance against doubtful accounts receivable associated with disputed contractual matters, and a charge of $.3 million to settle a disputed custom fee.

The effects of nonrecurring items on quarterly results of 2002 and 2001 are presented on page F-41 of this Form 10-K report.

Exploration and Production – Earnings from exploration and production operations were $161 million in 2002, $187.5 million in 2001 and $245.7 million in 2000. The decline in 2002 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 record production of both crude oil and natural gas and a 10% higher average sales price for crude oil and condensate. Oil production from continuing operations increased by 13% in 2002 to 75,213 barrels per day and natural gas production from continuing operations rose by 5% to 292.9 million cubic feet per day. 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. Based on an agreement with the U.S. government, the Company may not seek approval for development of this significant natural gas discovery in Destin Dome until at least 2012. The decline in 2001 was primarily attributable to an 18% decline in the Company's average oil sales price compared to 2000. Additionally, exploration expenses increased over 2000, a significant portion of which were in foreign jurisdictions where the Company has no realized income tax benefits. Production of crude oil, condensate and natural gas liquids from continuing operations increased from 63,917 barrels per day in 2000 to 66,344 in 2001, a 4% increase. Natural gas sales volumes from continuing operations totaled 278.3 million cubic feet per day in 2001, up 23% from 226 million in 2000.

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-36 and F-37 of this Form 10-K report. Daily production and sales rates and weighted average sales prices are shown on page 13 of the 2002 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)	2002	2001	2000
United States			
Crude oil	$ 30.0	38.5	53.2
Natural gas	111.3	192.8	211.4
Canada			
Crude oil	304.8	167.2	193.9
Natural gas	197.6	182.6	99.0
Synthetic oil	106.3	95.8	91.5
United Kingdom			
Crude oil	163.0	181.5	214.6
Natural gas	7.0	12.1	7.8
Ecuador – crude oil	30.7	33.4	52.2
Total oil and gas revenues	$ 950.7	903.9	923.6

The Company's crude oil, condensate and natural gas liquids production from continuing operations averaged 75,213 barrels per day in 2002, 66,344 in 2001 and 63,917 in 2000. Oil production in the United States declined 13% to 4,128 barrels per day in 2002, following an 11% decline in 2001. The reduction in both years was primarily due to declines from existing fields in the Gulf of Mexico. Oil production in Canada increased 34% in 2002 to a record volume of 48,239 barrels per day. The Terra Nova field, offshore Newfoundland, commenced production in January 2002 and averaged 12,463 barrels per day for the year. 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 higher capital spending related to an ongoing expansion project. Before royalties, the Company's synthetic oil production was 11,477 barrels per day in 2002, 11,157 in 2001 and 10,145 in 2000. 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. U.K. production was down by 1,912 barrels per day, or 9%, primarily due to declines from the Company's "T" Block and Ninian fields in the North Sea. The Company produced 4,544 barrels of oil per day in Ecuador, 15% lower than in 2001, primarily due to further pipeline constraints on the existing oil pipeline. An additional pipeline is scheduled to commence operation in the second half of 2003.

During 2001, oil production in the United States declined 14% compared to 2000 and averaged 4,752 barrels per day. The reduction was due to declines from existing fields in the Gulf of Mexico. Oil production in Canada increased 15% in 2001 to 36,059 barrels per day. The Company's share of net production at its synthetic oil operation improved 2,036 barrels per day, or 24%, in 2001 due to both higher gross production and a lower net profit royalty caused by increased capital spending and a lower oil price. Production of light oil increased 1,258 barrels per day, or 41%, and heavy oil production increased 11% to 11,707 barrels per day in 2001 with both increases primarily due to the Company's acquisition of Beau Canada in November 2000. Production at Hibernia rose 4% in 2001 to 9,535 barrels per day due to better operating efficiency, primarily associated with improved handling of gas production. U.K. production was down by 681 barrels per day, or 3%, due to declines from the Company's existing fields in the North Sea. Oil production in Ecuador was 17% lower than 2000 and totaled 5,319 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 a record 292.9 million cubic feet per day in 2002, up from 278.3 million in 2001. Natural gas sales were 226 million cubic feet per day in 2000. Sales of natural gas in the United States were 88.1 million cubic feet per day in 2002, 112.6 million in 2001 and 141.4 million in 2000. The reductions in 2002 and 2001 were due to lower deliverability from maturing fields in the Gulf of Mexico. Natural gas sales in Canada in 2002 were at record levels for the seventh consecutive year as sales increased 30% to 197.9 million cubic feet per day. Canadian natural gas sales had increased more than 100% in 2001. The increase in 2002 was primarily due to higher production from the Ladyfern field, while the 2001 increase was due to the acquisition of Beau Canada in late 2000 and from new discoveries, including Ladyfern, in western Canada. Natural gas sales in the United Kingdom were 7 million cubic feet per day in 2002, down 47% compared to 2001. U.K. natural gas sales in 2001 increased 21% compared to 2000 levels and totaled 13.1 million cubic feet per day. The lower production in 2002 was due to declines at the Amethyst field in the North Sea, while the added volumes in 2001 were attributable to higher production at both the Amethyst and Mungo/Monan fields.

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 a year ago. 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.

Worldwide crude oil sales prices declined during 2001 compared to 2000. In the United States, the Company's average sales price for crude oil and condensate was $24.92 per barrel for the year, down 18% compared to 2000. In Canada, sales prices for light oil fell 19% to $22.40 per barrel. Canadian heavy oil prices were down 38% from 2000 and averaged $11.06 per barrel. The sales price for Hibernia crude oil decreased 12% to $23.77 per barrel. Synthetic oil prices in 2001 averaged $25.04 per barrel, down 15% from a year ago. Sales prices in the U.K. were $24.44 per barrel, a decline of 12%, and sales prices in Ecuador were down 23% to $17.00 per barrel.

The Company's North American natural gas sales prices were weaker during 2002 compared to 2001 due generally 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.

North American natural gas sales price averaged $3.87 per MCF for the year 2001 compared to $3.90 in 2000. U.S. sales prices averaged $4.64 per MCF compared to $4.01 a year ago. However, the sales price for natural gas sold in Canada declined 11% to $3.28 per MCF. Prices in the United Kingdom increased to $2.52 per MCF from $1.81 in 2000.

Based on 2002 volumes and deducting taxes at marginal rates, each $1 per barrel and $.10 per MCF fluctuation in prices would have affected annual exploration and production earnings by $17.2 million and $5.8 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 $229.6 million in 2002, $211 million in 2001 and $176.1 million in 2000. These amounts are shown by major operating area on pages F-36 and F-37 of this Form 10-K report. Costs per equivalent barrel during the last three years excluding discontinued operations were as follows.

(Dollars per equivalent barrel)	2002	2001	2000
United States	$ 5.64	4.82	3.43
Canada			
Excluding synthetic oil	3.48	3.84	4.24
Synthetic oil	11.75	13.58	13.06
United Kingdom	5.03	3.75	3.46
Ecuador	8.17	7.60	6.65
Worldwide – excluding synthetic oil	4.29	4.24	3.96

The increase in the cost per equivalent barrel in the United States in both 2002 and 2001 was attributable to a combination of lower production and higher well servicing costs. Lower average costs 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 decrease in Canada during 2001, excluding synthetic oil, was primarily due to higher production of light oil, heavy oil and natural gas. 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, while the increased cost in 2001 was due to higher maintenance costs. 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. The increase in the United Kingdom during 2001 was also the result of higher costs for mature properties. Higher costs per unit in Ecuador in 2002 and 2001 were both 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-36 and F-37 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)	2002	2001	2000
Exploration and production			
Dry hole costs	$ 101.2	82.8	66.0
Geological and geophysical cost	23.4	36.0	36.3
Other costs	10.2	15.0	9.2
	134.8	133.8	111.5
Undeveloped lease amortization	24.6	23.1	14.1
Total exploration expenses	$ 159.4	156.9	125.6

The 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. Dry hole costs were higher in 2001 than in 2000 as more unsuccessful drilling costs off the east coast of Canada were partially offset by lower costs in the deepwater Gulf of Mexico. Geological and geophysical costs were down in 2002 due to less spending for 3-D seismic on deepwater concessions in Malaysia. Other exploration expenses were lower in 2002 primarily due to more recoveries from the Company's partner in Malaysia. Undeveloped leasehold amortization increased in 2001 compared to 2000 primarily because of lease acquisitions in western Canada.

Depreciation, depletion and amortization expense related to exploration and production operations totaled $247.2 million in 2002, $181.1 million in 2001 and $166.6 million in 2000. Higher costs in 2002 were caused by record 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 increase in 2001 was also due to higher oil and natural gas production volumes during the year.

The effective income tax rate for exploration and production operations was lower by approximately 1.5% of pretax earnings in 2002 compared to 2001 primarily due to higher benefits in the latter year from settlement of prior-year tax matters.

Approximately 94% of the Company's U.S. proved oil reserves and 48% of the U.S. proved natural gas reserves are undeveloped. At December 31, 2002, about 95% of the total U.S. undeveloped reserves relate to deepwater Gulf of Mexico fields, including Medusa, Front Runner and Habanero, which are currently being developed by the Company. Medusa is expected to come on stream at mid-year 2003. Habanero should start up in the third quarter 2003 and

Front Runner is currently projected to produce first oil in 2004. On a worldwide basis, the Company has spent approximately $239 million in 2002, $208 million in 2001 and $111 million in 2000 to develop its undeveloped proved reserves. The Company expects to spend about $314 million in 2003, $142 million in 2004 and $62 million in 2005 to move undeveloped proved reserves to the developed category.

The U.S. Securities and Exchange Commission (SEC) is currently in the process of obtaining 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 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 the initial discovery of four offshore fields based on conclusive formation tests rather than actual production tests. At the end of 2002, proved reserves for these four fields totaled 92 million barrels of oil equivalent, or approximately 20% of the Company's worldwide proved reserves. Three of the fields are currently being developed, including the Medusa, Front Runner and Habanero fields, with expected first production for these fields ranging from mid-2003 to the first 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 $39.9 million in 2002. Earnings from this business were a record $153.7 million in 2001, including nonrecurring gains, while earnings in 2000 totaled $54.5 million. The unfavorable result in 2002 was 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 6% and 4% higher, respectively, 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. North American operations, which now includes refining activities in the U.S. and marketing activities in the U.S. and Canada and formerly included pipeline and trucking operations in Canada prior to the sale of this business in 2001, lost $39.2 million in 2002 compared to profits of $139.6 million in 2001 and $31.5 million in 2000. The year 2001 included the aforementioned $71 million gain on sale of pipeline and trucking operations in Canada. Excluding this gain, the 2001 results were much improved over 2000 due to stronger refining and marketing margins and a higher percentage of sales through the Company's retail stations at Wal-Mart sites. Prior to the sale of the Canadian operations in 2001, this business generated a profit of $3.8 million in 2001 and $7.6 million in 2000. Operations in the U.K. lost $.7 million in 2002, but earned $14.1 million and $23 million in 2001 and 2000, respectively. The declines in 2002 and 2001 earnings compared to the prior year in the U.K. were caused by generally weaker refining margins than in the year before.

Unit margins (sales realizations less costs of crude oil, other feedstocks, refining operating expenses and depreciation and transportation to point of sale) averaged $.95 per barrel in North America in 2002, $3.23 in 2001 and $1.91 in 2000. North American product sales volumes increased 1% to a record 176,427 barrels per day in 2002, following a 17% increase in 2001. Sales volumes through the Company's retail gasoline network at Wal-Mart stores continued to grow steadily throughout 2002, but lower sales volumes into the wholesale market, caused by lower finished products produced by the Company's refineries, mostly offset this increase. Higher product sales volumes in 2001 was attributable to a combination of higher crude oil throughputs compared to the previous year at the Company's U.S. refineries, plus continued expansion of the Company's retail gasoline network at Wal-Mart stores.

Unit margins in the United Kingdom averaged $1.70 per barrel in 2002, $3.29 in 2001 and $4.69 in 2000. Sales of petroleum products were up 10% in 2002 to 34,204 barrels per day, while 2001 volumes were 4% higher than 2000, with both years' increases caused by higher volumes sold in the cargo market.

Both U.S. and U.K. operations were experiencing losses during January 2003 due to unit margins being significantly weaker during this period compared to the 2002 average.

Based on sales volumes for 2002 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 $20.5 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 and expense and corporate overhead not allocated to operating functions, were $23.6 million in 2002, $12.8 million in 2001 and $1.7 million in 2000. The higher net cost in 2002 compared to 2001 was due to a combination of more net interest expense associated with higher borrowings and lower interest income earned. Net costs were higher in 2001 than in 2000 mainly because the earlier year included more income tax benefits and associated interest income from settlement of prior year tax matters.

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 $868.1 million in 2002 compared to $864.4 million in 2001 and $557.9 million in 2000. These amounts included $134.8 million, $133.8 million and $111.5 million of exploration costs that were expensed. Capital expenditures for exploration and production activities totaled $631.8 million in 2002, 73% of the Company's total capital expenditures for the year. Exploration and production capital expenditures in 2002 included $18.5 million for acquisition of undeveloped leases, $232.4 million for exploration activities, and $380.9 million for development projects. Development expenditures included $149.4 million for development of deepwater discoveries in the Gulf of Mexico; $27.4 million for the Terra Nova and Hibernia oil fields, offshore Newfoundland; $54.1 million for expansion of synthetic oil operations at the Syncrude project in Canada; and $58.9 million for heavy oil and natural gas projects in western Canada. Exploration and production capital expenditures are shown by major operating area on page F-35 of this Form 10-K report.

Refining and marketing capital expenditures totaled $234.7 million in 2002, compared to $175.2 million in 2001 and $153.8 million in 2000. These amounts represented 27%, 20% and 28% of total capital expenditures of the Company in 2002, 2001 and 2000, respectively. Refining capital spending was $150.1 million in 2002, compared to $88.9 million in 2001 and $23.5 million in 2000. The Company is in the process of expanding its Meraux, Louisiana refinery by building a hydrocracker unit to meet future clean fuel specifications and is also increasing the crude oil processing capacity of the plant from 100,000 barrels of crude oil per day to 125,000 barrels per day. This project is to be completed by the end of the third quarter of 2003. Capital expenditures related to this expansion project amounted to $116.2 million in 2002 and $55.1 million in 2001. Marketing expenditures amounted to $84.6 million in 2002, $86.3 million in 2001 and $100.9 million in 2000. 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 125 total stations in the U.S. and Canada in 2002, 111 in 2001 and 131 in 2000. The Company acquired the minority interest in the Manito pipeline in 2000 at a cost of approximately $27 million. The Manito pipeline as well as other Canadian pipeline and trucking assets were sold in May 2001.

Cash Flows

Cash provided by continuing operations was $527 million in 2002, $630.6 million in 2001 and $738.1 million in 2000. Nonrecurring items decreased cash flow from continuing operations by $3.4 million in 2002, $32.3 million in 2001 and $2.7 million in 2000. The reductions in cash flow from nonrecurring items in 2002 and 2001 were mainly caused by cash income taxes related to gains on sale of assets. Changes in operating working capital other than cash and cash equivalents required cash of $24.2 million in 2002 and $28 million in 2001, but provided cash of $66 million in 2000. Cash provided by operating activities was further reduced by expenditures for refinery turnarounds and abandonment of oil and gas properties totaling $15.2 million in 2002, $16.4 million in 2001 and $16.6 million in 2000.

Cash proceeds from property sales were $68.1 million in 2002, $173 million in 2001 and $20.7 million in 2000. Borrowings under notes payable and other long-term debt provided $407.6 million of cash in 2002, $88.2 million in 2001 and $175 million in 2000. Cash proceeds from stock option exercises and employee stock purchase plans amounted to $25.1 million in 2002, $18.9 million in 2001 and $3.8 million in 2000.

Property additions and dry hole costs required $834.1 million of cash in 2002, $810.2 million in 2001 and $512.3 million in 2000. Cash outlays for debt repayment during the three years included $57.8 million in 2002, $77.7 million in 2001 and $130.5 million in 2000. The acquisition of Beau Canada in November 2000 utilized $127.5 million of cash. Cash used for dividends to stockholders was $70.9 million in 2002, $67.8 million in 2001 and $65.3 million in 2000. 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 $136.3 million in 2002, $38.6 million in 2001 and $71.7 million in 2000. 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 $129 million below current cost at December 31, 2002. Cash and cash equivalents at the end of 2002 totaled $165 million compared to $82.7 million a year ago and $132.7 million at the end of 2000.

Long-term debt increased by $342 million during 2002 to $862.8 million at the end of the year, 35.1% of total capital employed, and included $74.3 million of nonrecourse debt incurred in connection with the acquisition and development of the Hibernia oil field. The increase in long-term debt in 2002 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 and an expansion project at the Company's Meraux, Louisiana refinery. Long-term debt totaled $520.8 million at the end of 2001 compared to $524.8 million at December 31, 2000. Stockholders' equity was $1.6 billion at the end of 2002 compared to $1.5 billion a year ago and $1.3 billion at the end of 2000. A summary of transactions in stockholders' equity accounts is presented on page F-5 of this Form 10-K report.

Murphy had commitments of $623 million for capital projects in progress at December 31, 2002, including $82.1 million related to clean fuels and crude throughput expansion projects at the Meraux refinery; $126.3 million for costs to develop deepwater Gulf of Mexico fields, including Medusa, Front Runner and Habanero; $110.2 million for continued expansion of synthetic oil operations in Canada; and $121.8 million for future combined work commitments in Malaysia and offshore Nova Scotia. The expansion projects at the Meraux refinery include construction of a hydrocracker unit that will allow the refinery to produce low-sulfur products, an expansion of the crude oil processing capacity from 100,000 barrels per day to 125,000 barrels per day, and construction of an additional sulfur recovery complex. See further discussion regarding the Meraux projects on page 4 of this Form 10-K report.

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. The Company anticipates that long-term debt will increase during 2003 because of significant capital expenditure commitments, as described in the preceding paragraph, and an expectation that oil and natural gas prices for much of 2003 will remain below trading ranges experienced in 2002. At December 31, 2002, the Company had access to short-term and long-term revolving credit facilities in the amount of $488 million. 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 F to the consolidated financial statements. At February 1, 2003 the Company's long-term debt rating by Standard and Poor's was "A-" and by Moody's was "Baa1". The Company's ratio of earnings to fixed charges was 3.2 to 1 in 2002, 11.3 to 1 in 2001 and 13.4 to 1 in 2000.

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, 11 terminals, and approximately 80 service stations, for which known or potential obligations for environmental remediation exist. In addition the Company operates or has operated numerous oil and gas fields that may require some form of remediation; this cost is generally provided for within the Company's liability for accrued dismantlement costs.

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 Company has received notices from the U.S. Environmental Protection Agency (EPA) that it is currently considered a Potentially Responsible Party (PRP) at two Superfund sites. The potential total cost to all parties to perform necessary remedial work at these sites may be substantial. At one site the Company has agreed to pay $8,100 to obtain a release from further obligations. The Company's insurance carrier has agreed to reimburse the $8,100. Based on currently available information, the Company has reason to believe that it is also a *de minimus* party as to ultimate responsibility at the other Superfund site. 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 one remaining site or other Superfund sites. The Company does not believe that the ultimate costs to clean-up the two Superfund sites will have a material adverse effect on its net income or cash flows in a future period.

There is the possibility that environmental expenditures could be required at currently unidentified sites, and new or revised regulations could require additional expenditures at known sites. However, based on information currently available to the Company, the amount of future remediation costs incurred at known or currently unidentified sites is not expected to have a material adverse effect on future earnings 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, 2002.

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 $3.3 million in 2002. 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 $166 million in 2002 and are projected to be $120 million in 2003.

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 late 2002 and early 2003, 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-10 of this Form 10-K report, Murphy adopted 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. In addition, the Company adopted a change in accounting for unsold crude oil production effective January 1, 2000 that resulted in an $8.7 million charge to earnings in 2000 for the cumulative effect of the accounting change.

In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*. SFAS No. 141 requires that all future business combinations 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 unamortized goodwill of $51 million at December 31, 2002, which has been tested for impairment as required by SFAS No. 142 at year-end 2002. 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. In the fourth quarter 2002, the Company sold its interest in Ship Shoal Block 113 at a gain of $10.6 million. Following the guidance of SFAS No. 144, Murphy has recorded the gain on disposal, plus the normal operating results, of Ship Shoal Block 113 as discontinued operations for all years presented.

The Company adopted Emerging Issues Task Force (EITF) Issue 02-3 in the fourth quarter 2002. This consensus requires that the results of energy trading activities be recorded on a net margin basis. Accordingly, Murphy has reflected the results of its crude oil trading activities as net revenue in its income statement, and previously reported revenues and cost of sales have been reduced by equal and offsetting amounts, with no changes to net income or cash flows. The effect of this reclassification was a net reduction of both net sales and cost of crude oil, natural gas and product purchases by approximately $269 million in 2002, $600 million in 2001 and $1.03 billion in 2000.

In July 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 requires the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability must be recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed in service. When the liability is initially recorded, the Company will increase the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Upon adoption of SFAS No. 143 on January 1, 2003, the Company will recognize transition adjustments for existing asset retirement obligations, long-lived assets and accumulated depreciation, all net of related income tax effects, as the cumulative effect of a change in accounting principle. After adoption, 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 Company is unable to estimate the financial statement impact as of January 1, 2003 from adoption of SFAS No. 143.

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections*. 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, as the use of such extinguishments have become part of the risk management strategy of many companies. SFAS No. 145 also amends SFAS No. 13 to require sale-leaseback accounting for certain lease modifications that have economic effects similar to sale-leaseback transactions. The provisions of the Statement related to the rescission of Statement No. 4 is applied in fiscal years beginning after May 15, 2002. Earlier application of these provisions is encouraged. The provisions of the Statement related to Statement No. 13 were effective for transactions occurring after May 15, 2002, with early application encouraged. The adoption of SFAS No. 145 is not expected to have a material effect on the Company's financial statements.

In June 2002, the FASB issues SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. 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 provisions of this Statement are effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. The adoption of SFAS No. 146 is not expected to have a material effect on the Company's financial statements.

In November 2002, the FASB issued 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*. This Interpretation elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees issued. The Interpretation also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken. The initial recognition and measurement provisions of the Interpretation are applicable to guarantees issued or modified after December 31, 2002 and are not expected to have a material effect on the Company's financial statements. The disclosure requirements are effective for financial statements of interim and annual periods ending after December 15, 2002.

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. Certain of the disclosure modifications are required for fiscal years ending after December 15, 2002 and are included in the notes to these consolidated financial statements.

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*. This Interpretation addresses the consolidation by business enterprises of variable interest entities as defined in the Interpretation. The Interpretation applies immediately to variable interests in variable interest entities created after January 31, 2003, and to variable interests in variable interest entities obtained after January 31, 2003. For public enterprises with a variable interest in a variable interest entity created before February 1, 2003, the Interpretation is applied no later than the beginning of the first interim reporting period beginning after June 15, 2003. The application of this Interpretation is not expected to have a material effect on the Company's financial statements. The Interpretation requires certain disclosures in financial statements issued after January 31, 2003 if it is reasonably possible that the Company will consolidate or disclose information about variable interest entities when the Interpretation becomes effective.

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. 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.

- *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 and all development capital expenditures are capitalized and systematically charged to expense using the units of production method based on proved developed oil and natural gas reserves as estimated by the Company's engineers. The Company also uses proved developed reserves to recognize expense for future estimated dismantlement and abandonment costs. Costs of exploration wells in progress at year-end 2002 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, and future inflation levels. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserves, 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 of impairment charges 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 deductible 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 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, throughput contract, hydrogen supply agreement and capital commitments. Total payments due after 2002 under such contractual obligations are shown below.

		Amounts Due			
(Millions of dollars)	Total	2003	2004-2006	2007-2008	After 2008
Long-term debt	$ 919.9	57.1	257.1	6.6	599.1
Operating leases	190.2	20.5	58.2	37.0	74.5
Throughput contract	26.9	1.5	4.5	3.0	17.9
Hydrogen purchases	79.4	1.3	15.9	10.6	51.6
Capital commitments	623.0	596.2	26.8	–	–
Total	$ 1,839.4	676.6	362.5	57.2	743.1

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.

		Commitment Expiration per Period			
(Millions of dollars)	Total	2003	2004-2006	2007-2008	After 2008
Financial guarantees	$ 12.7	.5	1.8	1.3	9.1
Letters of credit	27.8	4.7	5.6	7.7	9.8
Total	$ 40.5	5.2	7.4	9.0	18.9

Outlook

Prices for the Company's primary products are often quite volatile. During late 2002 and early 2003, crude oil prices increased significantly primarily due to the near-term potential for a conflict between Iraq and a U.S.-led coalition of armed forces coupled with a nationwide oil worker strike in Venezuela that virtually halted oil exports from this OPEC nation. Because of the generally recognized "war premium" built into oil prices in early 2003, earnings and cash flows from the Company's refining and marketing operations remained very weak. Natural gas prices in late 2002 and early 2003 were stronger than the average for 2002, mainly due to a combination of cold weather in the early winter period and lower gas storage levels compared to the same time a year earlier. If a conflict in Iraq occurs, worldwide crude oil prices could change significantly depending on the war's effect on Middle Eastern oil production. In such a volatile environment, constant reassessment of spending plans is required.

The Company's capital expenditure budget for 2003 was prepared during the fall of 2002 and provides for expenditures of $952 million. Of this amount, $734 million or 77%, is allocated for exploration and production. Geographically, 39% of the exploration and production budget is allocated to the United States, including $191 million for development of deepwater projects in the Gulf of Mexico; another 32% is allocated to Canada, including $23 million for natural gas development, $28 million for heavy oil development, $30 million for continued development of the Hibernia and Terra Nova fields, and $69 million for further expansion of synthetic oil operations; 21% is allocated to exploration and development in Malaysia; and the remaining 8% is planned for other areas, including Ecuador and the United Kingdom. Budgeted refining and marketing capital expenditures for 2003 are $216 million, including $201 million in North America and $15 million in the United Kingdom. Planned spending in North America include funds to complete the clean fuels and crude throughput expansion projects at the Meraux refinery and to build over 100 additional gasoline stations at Wal-Mart sites. Capital and other expenditures are under constant review and planned capital expenditures may be adjusted to reflect changes in estimated cash flow during 2003.

Based on the Company's projected capital expenditures in 2003 and continued refining and marketing margins early in the year, a portion of capital expenditures is anticipated to be funded through new long-term borrowings during the year. Murphy's 2003 Budget anticipates an increase in long-term debt of approximately $200 million during the year. Although the Company is actively managing capital expenditures in light of operating cash flows, it is possible that long-term debt could exceed the budgeted year-end 2003 levels, especially if cash flows are adversely affected in the upcoming months by a weakening of oil and natural gas sales prices and continued weak refining and marketing margins such as those experienced in late 2002 and early 2003.

In order to reduce volatility of oil and natural gas prices, the Company has entered into a series of financial contracts that cover approximately 25% of the Company's anticipated 2003 oil and natural gas production. The swap and collar contracts are accounted for as qualified hedges of 2003 sales prices and are more fully described on page 24 of this report.

Murphy's oil and natural gas production profile will continue to grow in 2003. Two new deepwater Gulf of Mexico fields, Medusa and Habanero, will start up in 2003. Also, the West Patricia field in Block SK 309, offshore Sarawak, Malaysia is expected to produce first oil in the second quarter of 2003. A new heavy oil pipeline in Ecuador that is owned by others should be online in late 2003; this should allow the Company's daily production to more than double in this country by year-end 2003. These new fields will more than offset normal production declines at other fields. Total production for 2003 should average 130,000 to 135,000 barrels of oil equivalent per day.

In early 2003, the Company signed a letter of intent to sell its interests in the Ninian and Columba fields in the U.K. North Sea at a price of $36 million. This sale is expected to close in the second quarter 2003.

Murphy Oil and certain of its subsidiaries maintain defined benefit retirement plans covering most of its full-time employees. During 2002, the Company reduced the expected investment return for assets held in its U.S. retirement plans from 8.5% to 8.0%. The Company has decided to reduce its expected return to 7.5% in 2003. Due to a reduction in bond yields during 2002, the Company has also reduced the plans' discount rates from 7.25% in 2002 to 6.75% in 2003. 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 and a negative actual return on plan assets. 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 negative asset returns and liability changes will adversely impact the Company's pension expense in 2003. The Company's annual retirement plan expense is estimated to increase by about $8 million for 2003 compared to 2002. The Company is required to fund payments of $.3 million into one union plan in 2003. Unless asset values recover during the next few years, the Company's pension expense will continue to be adversely affected by negative asset returns experienced in recent years. In addition, 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, 2002 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, 2002, 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 $3.8 million at December 31, 2002.

At December 31, 2002, 20% of the Company's debt had variable interest rates and 4.6% was denominated in Canadian dollars. Based on debt outstanding at December 31, 2002, a 10% increase in variable interest rates would increase the Company's interest expense in 2003 by approximately $.2 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 2003 by $.9 million for debt denominated in Canadian dollars.

Murphy was a party to natural gas swap agreements at December 31, 2002 for a total notional volume of 9.2 MMBTU that are intended to hedge the financial exposure of its Meraux, Louisiana refinery to fluctuations in the future price of a portion of natural gas to be purchased for fuel during 2004 through 2006. In each month of settlement, the swaps require Murphy to pay an average natural gas price of $2.78 per MMBTU and to receive the average NYMEX price for the final three trading days of the month. At December 31, 2002, the estimated fair value of these agreements was recorded as an asset of $12.4 million. A 10% increase in the average NYMEX price of natural gas would have increased this asset by $3.7 million, while a 10% decrease would have reduced the asset by a similar amount.

The Company was a party to natural gas swap agreements and natural gas collar agreements at December 31, 2002 that are intended to hedge the financial exposure of a limited portion of its 2003 U.S. and Canadian natural gas production to changes in gas sales prices. The swap agreements are for a combined notional volume that averages 24,200 MMBTU per day and require Murphy to pay the average relevant index price for each month and receive an average price of $3.76 per MMBTU. The collar agreements are for a combined notional volume of 26,700 MMBTU per day and based upon the relevant index prices provide Murphy with an average floor price of $3.24 per MMBTU and an average ceiling price of $4.64 per MMBTU. At December 31, 2002, the estimated fair value of these agreements was recorded as a liability of $6.4 million, with the offsetting loss recorded in Accumulated Other Comprehensive Loss (AOCL) in Stockholders' Equity. A 10% increase in the average index price of natural gas would have increased this liability by $3.7 million, while a 10% decrease would have reduced the liability by a similar amount.

In addition, the Company was a party to crude oil swap agreements at December 31, 2002 that are intended to hedge the financial exposure of a limited portion of its 2003 U.S. and Canadian crude oil production to changes in crude oil sales prices. A portion of the swap agreements cover a notional volume of 22,000 barrels per day of light oil and require Murphy to pay the average of the closing settlement price on the NYMEX for the Nearby Light Crude Futures Contract for each month and receive an average price of $25.30 per barrel. Additionally, there are heavy oil swap agreements with a notional volume of 10,000 barrels per day that require Murphy to pay the arithmetic average of the posted prices for each month at the Kerrobert and Hardisty terminals in Canada and receive an average price of $16.74 per barrel. At December 31, 2002, the estimated fair value of these agreements was recorded as a liability of $19.9 million, with the offsetting loss recorded in AOCL in Stockholders' Equity. A 10% increase in the average index price of crude oil would have increased this liability by $28 million, while a 10% decrease would have reduced the liability by a similar amount.

Item 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

Information required by this item appears on pages F-1 through F-41, which follow page 31 of this Form 10-K report.

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

None

PART III

Item 10. ***DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT***

Certain information regarding executive officers of the Company is included on page 6 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 14, 2003 under the caption "Election of Directors."

Item 11. *EXECUTIVE COMPENSATION*

Information required by this item is incorporated by reference to the Registrant's definitive Proxy Statement for the Annual Meeting of Stockholders on May 14, 2003 under the captions "Compensation of Directors," "Executive Compensation," "Option Exercises and Fiscal Year-End Values," "Option Grants," "Compensation Committee Report for 2002," "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 the Registrant's definitive Proxy Statement for the Annual Meeting of Stockholders on May 14, 2003 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

PART IV

Item 14. *CONTROLS AND PROCEDURES*

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

Based on their evaluation as of a date within 90 days of 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-14(c) and 15d-14(c) 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 or in other factors that could significantly affect those controls subsequent to the date of their most recent evaluation.

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.

	Page No.
Report of Management	F-1
Independent Auditors' Report	F-1
Consolidated Statements of Income	F-2
Consolidated Balance Sheets	F-3
Consolidated Statements of Cash Flows	F-4
Consolidated Statements of Stockholders' Equity	F-5
Consolidated Statements of Comprehensive Income	F-6
Notes to Consolidated Financial Statements	F-7
Supplemental Oil and Gas Information (unaudited)	F-32
Supplemental Quarterly Information (unaudited)	F-40

2. Financial Statement Schedules

Schedule II – Valuation Accounts and Reserves F-42

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

3. Exhibits – The following is an index of exhibits that are hereby filed as indicated by asterisk (*), that are to be filed by an amendment as indicated by pound sign (#), 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 May 8, 2002	Exhibit 3.2 of Murphy's Form 10-Q report for the quarterly period ended June 30, 2002
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.	

Exhibit No.		Incorporated by Reference to
4.1	Form of Second Supplemental Indenture between Murphy Oil Corporation and SunTrust Bank, as Trustee	Exhibit 4.1 of Murphy's Form 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	
10.2	Employee Stock Purchase Plan as amended May 10, 2000	Exhibit 99.01 of Murphy's Form S-8 Registration Statement filed August 4, 2000 under the Securities Act of 1933
*10.3	Motor Vehicle Fueling Station Master Ground Lease Agreement	
*12.1	Computation of Ratio of Earnings to Fixed Charges	
*13	2002 Annual Report to Security Holders including Narrative to Graphic and Image Material as an appendix	
*21	Subsidiaries of the Registrant	
*23	Independent Auditors' Consent	
*99.1	Undertakings	
*99.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	
*99.3	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	

Exhibit No.		Incorporated by Reference to
#99.4	Form 11-K, Annual Report for the fiscal year ended December 31, 2002 covering the Thrift Plan for Employees of Murphy Oil Corporation	To be filed as an amendment to this Form 10-K report not later than 180 days after December 31, 2002
#99.5	Form 11-K, Annual Report for the fiscal year ended December 31, 2002 covering the Thrift Plan for Employees of Murphy Oil USA, Inc. Represented by United Steelworkers of America, AFL-CIO, Local No. 8363	To be filed as an amendment to this Form 10-K report not later than 180 days after December 31, 2002
#99.6	Form 11-K, Annual Report for the fiscal year ended December 31, 2002 covering the Thrift Plan for Employees of Murphy Oil USA, Inc. Represented by International Union of Operating Engineers, AFL-CIO, Local No. 305	To be filed as an amendment to this Form 10-K report not later than 180 days after December 31, 2002

(b) Reports on Form 8-K

A report on form 8-K was filed on December 5, 2002 announcing that the Board of Directors of the Company had declared a two-for-one stock split of the common stock of Murphy Oil Corporation effective December 30, 2002.

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

I, Claiborne P. Deming, certify that:

1. I have reviewed this annual report on Form 10-K of Murphy Oil Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 21, 2003

/s/ Claiborne P. Deming
Claiborne P. Deming
Principal Executive Officer

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

I, Steven A. Cossé, certify that:

1. I have reviewed this annual report on Form 10-K of Murphy Oil Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 21, 2003

/s/ Steven A. Cossé
Steven A. Cossé
Principal Financial Officer

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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 21, 2003

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on March 21, 2003 by the following persons on behalf of the registrant and in the capacities indicated.

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

R. MADISON MURPHY
R. Madison Murphy, Director

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

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

GEORGE S. DEMBROSKI
George S. Dembroski, Director

CAROLINE G. THEUS
Caroline G. Theus, Director

H. RODES HART
H. Rodes Hart, Director

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

ROBERT A. HERMES
Robert A. Hermes, Director

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 periodically 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, and 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, 2002 and 2001, 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, 2002. 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, 2002 and 2001, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2002, 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, 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.

Shreveport, Louisiana
February 14, 2003

KPMG LLP

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 (Thousands of dollars except per share amounts)	2002	2001*	2000*
Revenues			
Sales and other operating revenues	$ 3,966,516	3,743,986	3,630,195
Gain on sale of assets	9,148	105,504	4,010
Interest and other income	8,663	16,478	23,981
Total revenues	3,984,327	3,865,968	3,658,186
Costs and Expenses			
Crude oil, natural gas and product purchases	2,676,012	2,370,550	2,324,591
Operating expenses	540,019	479,336	412,822
Exploration expenses, including undeveloped lease amortization	159,429	156,919	125,629
Selling and general expenses	98,562	97,835	85,474
Depreciation, depletion and amortization	300,022	226,621	210,906
Amortization of goodwill	–	3,120	–
Impairment of properties	31,640	10,478	27,916
Interest expense	51,504	39,289	29,936
Interest capitalized	(24,536)	(20,283)	(13,599)
Total costs and expenses	3,832,652	3,363,865	3,203,675
Income from continuing operations before income taxes	151,675	502,103	454,511
Income tax expense	54,165	173,673	155,985
Income from continuing operations	97,510	328,430	298,526
Discontinued operations, net of tax (including gain on disposal in 2002 of $10,650)	13,998	2,473	7,035
Cumulative effect of accounting change, net of tax (Note B)	–	–	(8,733)
Net Income	$ 111,508	330,903	296,828
Income (Loss) per Common Share – Basic			
Income from continuing operations	$ 1.07	3.63	3.32
Discontinued operations	.15	.03	.08
Cumulative effect of accounting change	–	–	(.10)
Net Income – Basic	$ 1.22	3.66	3.30
Income (Loss) per Common Share – Diluted			
Income from continuing operations	$ 1.06	3.60	3.30
Discontinued operations	.15	.03	.08
Cumulative effect of accounting change	–	–	(.10)
Net Income – Diluted	$ 1.21	3.63	3.28
Average Common shares outstanding – basic	91,450,836	90,442,944	90,063,330
Average Common shares outstanding – diluted	92,134,967	91,181,998	90,479,412

*Reclassified to conform to 2002 presentation.

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

December 31 (Thousands of dollars)	2002	2001
Assets		
Current assets		
Cash and cash equivalents	$ 164,957	82,652
Accounts receivable, less allowance for doubtful accounts of $9,307 in 2002 and $11,263 in 2001	408,782	262,022
Inventories, at lower of cost or market		
Crude oil and blend stocks	41,961	38,917
Finished products	94,158	85,133
Materials and supplies	65,225	49,098
Prepaid expenses	59,962	61,062
Deferred income taxes	19,115	19,777
Total current assets	854,160	598,661
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $3,361,726 in 2002 and $3,277,673 in 2001	2,886,599	2,525,807
Goodwill, net	51,037	50,412
Deferred charges and other assets	93,979	84,219
Total assets	$ 3,885,775	3,259,099
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long-term debt	$ 57,104	48,250
Accounts payable	447,740	325,323
Income taxes	61,559	48,378
Other taxes payable	97,770	86,844
Other accrued liabilities	53,719	51,262
Total current liabilities	717,892	560,057
Notes payable	788,554	416,061
Nonrecourse debt of a subsidiary	74,254	104,724
Deferred income taxes	327,771	302,868
Accrued dismantlement costs	160,543	160,764
Accrued major repair costs	52,980	44,570
Deferred credits and other liabilities	170,228	171,892
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, 2002 and 2001, issued 94,613,379 and 48,775,314 shares at December 31, 2002 and 2001, respectively	94,613	48,775
Capital in excess of par value	504,983	527,126
Retained earnings	1,137,177	1,096,567
Accumulated other comprehensive loss	(66,790)	(83,309)
Unamortized restricted stock awards	–	(968)
Treasury stock	(76,430)	(90,028)
Total stockholders' equity	1,593,553	1,498,163
Total liabilities and stockholders' equity	$ 3,885,775	3,259,099

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)	2002	2001*	2000*
Operating Activities			
Income from continuing operations	$ 97,510	328,430	298,526
Adjustments to reconcile above income to net cash provided by operating activities			
Depreciation, depletion and amortization	300,022	226,621	210,906
Impairment of properties	31,640	10,478	27,916
Provisions for major repairs	24,996	21,070	22,761
Expenditures for major repairs and dismantlement costs	(15,188)	(16,395)	(16,603)
Dry hole costs	101,201	82,825	65,987
Amortization of undeveloped leases	24,634	23,154	14,076
Amortization of goodwill	–	3,120	–
Deferred and noncurrent income tax charges	5,871	80,052	63,431
Pretax gains from disposition of assets	(9,148)	(105,504)	(4,010)
Net (increase) decrease in noncash operating working capital excluding acquisition of Beau Canada Exploration Ltd.	(24,213)	(27,951)	66,002
Cumulative effect of accounting change on working capital	–	–	(11,170)
Other operating activities – net	(10,356)	4,731	261
Net cash provided by continuing operations	526,969	630,631	738,083
Net cash provided by discontinued operations	5,875	5,073	9,668
Net cash provided by operating activities	532,844	635,704	747,751
Investing Activities			
Property additions and dry hole costs	(834,056)	(810,152)	(512,331)
Acquisition of Beau Canada Exploration Ltd., net of cash acquired	–	–	(127,476)
Proceeds from sale of property, plant and equipment	68,056	172,972	20,705
Other investing activities – net	(2,177)	(1,410)	391
Investing activities of discontinued operations	6,731	(3,348)	–
Net cash required by investing activities	(761,446)	(641,938)	(618,711)
Financing Activities			
Additions to notes payable	407,053	87,000	175,000
Reductions of notes payable	(32,457)	(62,214)	(124,254)
Additions to nonrecourse debt of a subsidiary	573	1,241	–
Reductions of nonrecourse debt of a subsidiary	(25,354)	(15,499)	(6,207)
Proceeds from exercise of stock options and employee stock purchase plans	25,131	18,864	3,769
Cash dividends paid	(70,898)	(67,826)	(65,294)
Other financing activities – net	(2,778)	(3,050)	(7,894)
Net cash provided (required) by financing activities	301,270	(41,484)	(24,880)
Effect of exchange rate changes on cash and cash equivalents	9,637	(2,331)	(5,591)
Net increase (decrease) in cash and cash equivalents	82,305	(50,049)	98,569
Cash and cash equivalents at January 1	82,652	132,701	34,132
Cash and cash equivalents at December 31	$ 164,957	82,652	132,701

*Reclassified to conform to 2002 presentation.

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)	2002	2001	2000
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	–	–	–
Common Stock – par $1.00, authorized 200,000,000 shares at December 31, 2002 and 2001 and 80,000,000 shares at December 31, 2000, issued 94,613,379 shares at December 31, 2002 and 48,775,314 shares at beginning and end of 2001 and 2000			
Balance at beginning of year	$ 48,775	48,775	48,775
Two-for-one stock split effective December 30, 2002	45,838	–	–
Balance at end of year	94,613	48,775	48,775
Capital in Excess of Par Value			
Balance at beginning of year	527,126	514,474	512,488
Exercise of stock options, including income tax benefits	20,039	10,440	1,749
Restricted stock transactions	2,563	1,272	(202)
Sale of stock under employee stock purchase plans	1,093	940	439
Two-for-one stock split effective December 30, 2002	(45,838)	–	–
Balance at end of year	504,983	527,126	514,474
Retained Earnings			
Balance at beginning of year	1,096,567	833,490	601,956
Net income for the year	111,508	330,903	296,828
Cash dividends – $.775 per share in 2002, $.75 per share in 2001 and $.725 per share in 2000	(70,898)	(67,826)	(65,294)
Balance at end of year	1,137,177	1,096,567	833,490
Accumulated Other Comprehensive Loss			
Balance at beginning of year	(83,309)	(38,266)	(4,984)
Foreign currency translation gains (losses)	30,878	(49,596)	(33,282)
Cash flow hedging gains (losses), net of income taxes	(13,007)	4,553	–
Minimum pension liability, net of income taxes	(1,352)	–	–
Balance at end of year	(66,790)	(83,309)	(38,266)
Unamortized Restricted Stock Awards			
Balance at beginning of year	(968)	(1,410)	(2,328)
Amortization, forfeitures and changes in price of Common Stock	968	442	918
Balance at end of year	–	(968)	(1,410)
Treasury Stock			
Balance at beginning of year	(90,028)	(97,503)	(98,735)
Exercise of stock options	12,852	6,833	1,140
Sale of stock under employee stock purchase plans	749	651	441
Awarded restricted stock, net of forfeitures, and other	(3)	(9)	(349)
Balance at end of year – 2,923,925 shares of Common Stock in 2002, 3,444,234 shares in 2001 and 3,729,769 shares in 2000	(76,430)	(90,028)	(97,503)
Total Stockholders' Equity	$ 1,593,553	1,498,163	1,259,560

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)	2002	2001	2000
Net income	$ 111,508	330,903	296,828
Other comprehensive income (loss), net of tax			
Cash flow hedges			
Net derivative gains (losses)	(8,065)	26	–
Reclassification adjustments	(4,942)	(2,115)	–
Total cash flow hedges	(13,007)	(2,089)	–
Net gain (loss) from foreign currency translation	30,878	(49,596)	(33,282)
Minimum pension liability adjustment, net of tax	(1,352)	–	–
Other comprehensive income (loss) before cumulative effect of accounting change	16,519	(51,685)	(33,282)
Cumulative effect of accounting change (Note B)	–	6,642	–
Other comprehensive income (loss)	16,519	(45,043)	(33,282)
Comprehensive Income	$ 128,027	285,860	263,546

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

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 and Ecuador and conducts 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, 2002 and 2001, 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-32 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. Estimated dismantlement, abandonment and site restoration costs, net of salvage value, are generally recognized using the units of production method and are included in depreciation expense. Costs for future dismantlement, abandonment and site restoration 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 disposals or retirements that are significant or include an entire depreciable or depletable property unit are included in income. Actual costs of dismantling oil and gas production facilities and site restoration are charged against the related liability. All other dispositions, retirements or abandonments are reflected in accumulated depreciation, depletion and amortization.

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 – Inventories of crude oil other than refinery feedstocks are valued 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) was recorded as goodwill. Through 2001, goodwill was amortized on a straight-line basis over 15 years, and its recoverability was assessed by determining whether future goodwill amortization can be recovered through undiscounted future net cash flows for western Canadian oil and gas properties. Effective January 1, 2002, in accordance with Statement of Financial Accounting Standards (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 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 the majority of 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 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 K 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 market 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 that was 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 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)		2002	2001	2000
Net income	– As reported	$ 111,508	330,903	296,828
	Pro forma	104,192	324,358	299,031
Net income per share	– As reported, basic	$ 1.22	3.66	3.30
	Pro forma, basic	1.14	3.59	3.32
	As reported, diluted	1.21	3.63	3.28
	Pro forma, diluted	1.13	3.56	3.30

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. Per share amounts for 2001 and 2000 have been restated to reflect the Company's two-for-one stock split effective December 30, 2002.

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

Effective January 1, 2002, the Company was required to adopt the Financial Accounting Standards Board's (FASB) SFAS No. 142, *Goodwill and Other Intangible Assets*, which 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. 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, 2002 was $51,037,000. The change in the carrying amount of goodwill at December 31, 2002 compared to December 31, 2001 was 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 after the oil and gas reserve information is available. 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. 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 was required to adopt 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.

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, $600,000,000 in 2001 and $1,030,000,000 in 2000.

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 have been designated as hedges of forecasted cash flow exposures. Changes in the fair value of a qualifying cash flow hedging derivative are deferred and recorded as a component of Accumulated Other Comprehensive Loss (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 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 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 years ended December 31, 2002 and 2001, losses of $4,942,000 and $2,115,000, net of $3,267,000 and $765,000 in taxes, respectively, were reclassified from AOCL to income.

In 2000, Murphy adopted the revenue recognition guidance in the Securities and Exchange Commission's Staff Accounting Bulletin 101. As a result of the change, Murphy records revenues related to its crude oil as the oil is sold, and carries its unsold crude oil production at cost rather than market value as in the past. Consequently, Murphy recorded a transition adjustment of $8,733,000, net of income tax benefits of $3,886,000, for the cumulative effect on prior years. Excluding the cumulative effect transition adjustment, this accounting change increased income in 2000 by $1,145,000. The transition adjustment included a cumulative reduction of revenue for years prior to the change of $20,591,000. Pro forma net income for the year ended December 31, 2000, assuming that the new revenue recognition method had been applied retroactively, was as follows.

(Thousands of dollars except per share data)		**2000**
Net income	– As reported	$ 296,828
	Pro forma	305,561
Net income per share	– As reported, basic	$ 3.30
	Pro forma, basic	3.39
	As reported, diluted	3.28
	Pro forma, diluted	3.38

In July 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*, which will require the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability must be recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed in service. When the liability is initially recorded, the Company will increase the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Upon adoption of SFAS No. 143 on January 1, 2003, the Company will recognize transition adjustments for existing asset retirement obligations, long-lived assets and accumulated depreciation, all net of related income tax effects, as the cumulative effect of a change in accounting principle. After adoption, 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 Company is unable to estimate the financial statement impact as of January 1, 2003 from adoption of SFAS No. 143.

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* 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, as the use of such extinguishments have become part of the risk management strategy of many companies. SFAS No. 145 also amends SFAS No. 13 to require sale-leaseback accounting for certain lease modifications that have economic effects similar to sale-leaseback transactions. The provisions of the Statement related to the rescission of Statement No. 4 is applied in fiscal years beginning after May 15, 2002. Earlier application of these provisions is encouraged. The provisions of the Statement related to SFAS No. 13 were effective for transactions occurring after May 15, 2002, with early application encouraged. The adoption of SFAS No. 145 is not expected to have a material effect on the Company's financial statements.

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* 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 provisions of this Statement are effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. The adoption of SFAS No. 146 is not expected to have a material effect on the Company's financial statements.

In November 2002, the FASB issued 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.* This Interpretation elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees issued. The Interpretation also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken. The initial recognition and measurement provisions of the Interpretation are applicable to guarantees issued or modified after December 31, 2002 and are not expected to have a material effect on the Company's financial statements. The disclosure requirements are effective for financial statements of interim and annual periods ending after December 31, 2002.

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. Certain of the disclosure modifications are required for fiscal years ending after December 15, 2002 and are included in the notes to these consolidated financial statements.

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51.* This Interpretation addresses the consolidation by business enterprises of variable interest entities as defined in the Interpretation. The Interpretation applies immediately to variable interests in variable interest entities created after January 31, 2003, and to variable interests in variable interest entities obtained after January 31, 2003. For public enterprises with a variable interest in a variable interest entity created before February 1, 2003, the Interpretation is applied no later than the beginning of the first interim reporting period beginning after June 15, 2003. The application of this Interpretation is not expected to have a material effect on the Company's financial statements. The Interpretation requires certain disclosures in financial statements issued after January 31, 2003 if it is reasonably possible that the Company will consolidate or disclose information about variable interest entities when the Interpretation becomes effective.

Note C – Discontinued Operations

In December 2002, the Company sold its investment 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, has been reported as Discontinued Operations in the Consolidated Statements of Income for all years presented. The property generated revenues, excluding gain on sale, of $15,515,000 in 2002, $13,410,000 in 2001 and $19,172,000 in 2000. Comparable pretax earnings from the field were $5,151,000 in 2002, $3,805,000 in 2001 and $10,823,000 in 2000.

Note D – Acquisition of Beau Canada Exploration Ltd.

In November 2000, Murphy acquired Beau Canada, an independent oil and natural gas company that primarily owned exploration licenses and producing natural gas and heavy oil fields in western Canada. The acquisition has been accounted for as a purchase. Beau Canada's operations subsequent to the acquisition date have been included in the Company's consolidated financial statements. The Company paid net cash of $127,476,000 to purchase all of Beau Canada's common stock at a price of approximately $1.44 per share.

The Company recorded property, plant and equipment of $260,000,000 associated with the purchase of Beau Canada. The Company valued the property, plant and equipment acquired using both proved and risked probable reserves as estimated by the Company's engineers and an estimate of future oil and natural gas sales prices based on the then prevailing pricing environment for the projected timing of future production.

The Company also assumed debt in the acquisition of $124,227,000 that was repaid by December 31, 2000 through issuance of a structured loan (see Note G). As subsequently adjusted in 2001, Murphy recorded goodwill of $56,280,000 associated with the Beau Canada acquisition, primarily due to the purchase price being greater than the fair value of the net assets acquired and deferred income tax liabilities required to be established in recording the acquisition.

The following table reflects the unaudited results of operations on a pro forma basis as if the Beau Canada acquisition had been completed at the beginning of 2000. The pro forma financial information is not necessarily indicative of the operating results that would have occurred had the acquisition been consummated as of January 1, 2000, nor is it necessarily indicative of future operating results.

(Thousands of dollars except per share data)	Year Ended December 31, 2000
Pro forma revenues	$ 3,746,595
Pro forma net income	303,479
Pro forma net income per Common share – diluted	3.35

Note E – Property, Plant and Equipment

	December 31, 2002		December 31, 2001	
(Thousands of dollars)	Cost	Net	Cost	Net
Exploration and production	$ 4,739,856	2,055,187*	4,553,034	1,885,124*
Refining	986,986	451,207	822,339	323,227
Marketing	476,633	354,412	384,520	290,244
Corporate and other	44,850	25,793	43,587	27,212
	$ 6,248,325	2,886,599	5,803,480	2,525,807

*Includes $20,721 in 2002 and $20,174 in 2001 related to administrative assets and support equipment.

In the 2002 and 2001 Consolidated Statements of Income, the Company recorded noncash charges of $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 $20,567,000 in 2002 and $6,811,000 in 2001. 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 F – Financing Arrangements

At December 31, 2002, the Company had three committed credit facilities with a major banking consortium totaling US $488,332,000. The Company and a subsidiary may borrow under a $150,000,000 revolving credit agreement maturing in December 2006. Additionally, the Company and the subsidiary have available a $169,166,000 364-day revolving credit agreement maturing in December 2003 with an option to convert any outstanding amounts to a one-year term loan at maturity. The Company's Canadian subsidiary has available a US $169,166,000 364-day revolving agreement with an option to convert any outstanding amounts to a five-year and one day term at maturity. The two 364-day revolving credit agreements are extendable for up to 364 days upon approval of a majority of the banking consortium. U.S. dollar and Canadian dollar commercial paper totaling an equivalent US $74,997,000 at December 31, 2002 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, 2002 totaling an equivalent US $127,323,000 for a combination of U.S. dollar and Canadian dollar borrowings. At December 31, 2002, US $40,200,000 of the committed credit facilities and US $68,000,000 of the uncommitted lines was outstanding and classified as long-term debt based on the ability of the Company to replace this debt with borrowings under the existing long-term credit facilities. 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 $650,000,000 in debt and equity securities.

Note G – Long-term Debt

December 31 (Thousands of dollars)	2002	2001
Notes payable		
6.375% notes, due 2012, net of unamortized discount of $1,072 at December 31, 2002	$ 348,928	–
7.05% notes, due 2029, net of unamortized discount of $2,447 at December 31, 2002	247,553	247,461
6.23% structured loan, due 2003-2005	117,486	149,832
Notes payable to bank, 1.74% to 2.03%, due 2003	108,200	50,000
Other, 6% to 8%, due 2003-2021	1,104	1,187
Total notes payable	823,271	448,480
Nonrecourse debt of a subsidiary		
Guaranteed credit facilities with banks		
Commercial paper, 1.445% to 2.775%, $8,800 payable in Canadian dollars, supported by credit facility, due 2003-2008	74,997	96,476
Loans payable to Canadian government, interest free, payable in Canadian dollars, due 2003-2008	21,644	24,079
Total nonrecourse debt of a subsidiary	96,641	120,555
Total debt including current maturities	919,912	569,035
Current maturities	(57,104)	(48,250)
Total long-term debt	$ 862,808	520,785

Maturities for the four years after 2003 are: $59,055,000 in 2004, $68,760,000 in 2005, $129,271,000 in 2006 and $3,314,000 in 2007.

Notes payable to bank due in 2003 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 Company has borrowed the maximum amount available under the Primary Guarantee Facility. 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.

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

Note H – Income Taxes

The components of income from continuing operations before income taxes for each of the three years ended December 31, 2002 and income tax expense (benefit) attributable thereto were as follows.

(Thousands of dollars)		2002	2001	2000
Income (loss) from continuing operations before income taxes				
United States		$(128,523)	157,251	91,696
Foreign		280,198	344,852	362,815
		$ 151,675	502,103	454,511
Income tax expense (benefit) from continuing operations				
Federal –	Current[1]	$ (41,531)	28,821	15,427
	Deferred	(1,349)	33,167	5,665
	Noncurrent	(6,824)	(4,136)	(2,261)
		(49,704)	57,852	18,831
State –	Current	(529)	4,710	3,129
Foreign –	Current	90,304	60,090	76,184
	Deferred[2]	16,982	50,916	59,776
	Noncurrent	(2,888)	105	(1,935)
		104,398	111,111	134,025
Total		$ 54,165	173,673	155,985

[1]Net of benefit of $10,939 in 2002 and $3,150 in 2000 for alternative minimum tax credits.
[2]Includes a charge of $1,997 in 2002 for an increase in the U.K. tax rate for North Sea oil production and a benefit of $5,540 in 2001 for a reduction in a provincial tax rate in Canada.

Income tax benefits attributable to employee stock option transactions of $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 and income tax (benefits) charges of $(8,885,000) in 2002 and $2,447,000 in 2001 relating to derivatives were included in AOCL.

Total income tax expense in 2002, 2001 and 2000, including taxes associated with discontinued operations and the cumulative effect of accounting change, was $61,702,000, $175,005,000, and $155,887,000, 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)	2002	2001	2000
Income tax expense based on the U.S. statutory tax rate	$ 53,086	175,736	159,079
Foreign income subject to foreign taxes at a rate different than the U.S. statutory rate	11,240	2,498	13,010
State income taxes	(344)	3,062	2,034
Settlement of U.S. taxes	(8,134)	(1,446)	(17,016)
Settlement of foreign taxes	–	(1,915)	–
Changes in foreign tax rates	1,997	(5,540)	–
Other, net	(3,680)	1,278	(1,122)
Total	$ 54,165	173,673	155,985

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2002 and 2001 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	2002	2001
Deferred tax assets		
Property and leasehold costs	$ 101,734	72,390
Liabilities for dismantlements and major repairs	83,072	68,755
Postretirement and other employee benefits	29,595	29,345
Federal alternative minimum tax credit carryforward	10,939	–
Foreign tax operating losses	20,989	26,844
Other deferred tax assets	29,413	22,029
Total gross deferred tax assets	275,742	219,363
Less valuation allowance	(89,574)	(67,745)
Net deferred tax assets	186,168	151,618
Deferred tax liabilities		
Property, plant and equipment	(52,993)	(53,494)
Accumulated depreciation, depletion and amortization	(394,726)	(343,925)
Other deferred tax liabilities	(47,105)	(37,290)
Total gross deferred tax liabilities	(494,824)	(434,709)
Net deferred tax liabilities	$ (308,656)	(283,091)

At December 31, 2002, the Company had tax losses and other carryforwards of $72,735,000 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 2003 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. The valuation allowance increased $21,829,000 and $6,787,000 in 2002 and 2001, respectively; the change in each year primarily offset the change in certain deferred tax assets. Any subsequent reductions of the valuation allowance will be reported as reductions of tax expense assuming no offsetting change in the deferred tax asset.

The Company has not recorded a deferred tax liability of $31,584,000 related to undistributed earnings of certain foreign subsidiaries at December 31, 2002 because the earnings are considered permanently invested.

Tax returns are subject to audit by various taxing authorities. In 2002, 2001 and 2000, the Company recorded benefits to income of $14,737,000, $3,361,000 and $25,618,000, 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 I – Incentive Plans

The Company's 1992 Stock Incentive Plan (the Plan) authorized the Executive Compensation and Nominating 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. 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 $5,288,000 in 2002, $1,892,000 in 2001, and $7,914,000 in 2000. 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. One-half of each grant may be exercised after two years and the remainder after three years. All disclosures that follow have been adjusted to reflect the two-for-one stock split effective December 30, 2002.

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

	Number of Shares	Average Exercise Price
Outstanding at December 31, 1999	2,508,738	$ 23.10
Granted at FMV	792,000	28.49
Exercised	(385,098)	21.82
Forfeited	(10,500)	24.88
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)	31.30
Outstanding at December 31, 2002	3,296,840	31.08
Exercisable at December 31, 2000	1,181,640	$ 25.90
Exercisable at December 31, 2001	1,270,240	24.57
Exercisable at December 31, 2002	988,340	25.01

Additional information about stock options outstanding at December 31, 2002 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	258,840	5.8	$ 18.04	258,840	$ 18.04
$24.88 to $28.48	1,010,500	6.2	27.43	617,000	26.76
$30.23 to $38.85	2,027,500	8.3	34.57	112,500	31.48
	3,296,840	7.5	31.08	988,340	25.01

The pro forma net income calculations in Note A reflect the following fair values of stock options granted in 2002, 2001 and 2000; fair values of options have been estimated by using the Black-Scholes pricing model and the assumptions as shown.

	2002	2001	2000
Fair value per option at grant date	$ 9.59	$ 7.20	$ 7.50
Assumptions			
Dividend yield	2.56%	2.84%	2.91%
Expected volatility	26.80%	26.34%	26.06%
Risk-free interest rate	4.89%	4.93%	6.76%
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. On December 31, 2000, approximately 50% of eligible shares granted in 1996 were awarded, and the remaining shares were forfeited based on financial objectives achieved. At December 31, 2002, eligible shares granted in 1998 were awarded to the grantees based on financial objectives achieved. Changes in restricted stock outstanding were as follows.

(Number of shares)	2002	2001	2000
Balance at beginning of year	115,166	116,666	166,728
Awarded	(115,166)	–	(24,154)
Forfeited	–	(1,500)	(25,908)
Balance at end of year	–	115,166	116,666

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 $3,911,000, $11,816,000 and $6,970,000 was recorded in 2002, 2001 and 2000, 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 24,828 shares at an average price of $38.94 per share in 2002, 27,350 shares at $25.54 in 2001 and 40,974 shares at $18.78 in 2000. At December 31, 2002, 141,913 shares remained available for sale under the ESPP. Compensation costs related to the ESPP were immaterial.

Note J – 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, 2002 and 2001 and a statement of the funded status as of December 31, 2002 and 2001.

	Pension Benefits		Postretirement Benefits	
(Thousands of dollars)	**2002**	**2001**	**2002**	**2001**
Change in benefit obligation				
Obligation at January 1	$ 261,182	247,718	43,335	38,454
Service cost	6,721	5,757	1,287	935
Interest cost	18,098	17,370	3,280	3,009
Plan amendments	227	–	–	–
Participant contributions	69	71	539	551
Actuarial loss	21,160	8,811	10,306	4,311
Settlements	–	(1,660)	–	–
Exchange rate changes	4,274	(1,773)	–	–
Benefits paid	(15,093)	(15,112)	(5,079)	(3,925)
Obligation at December 31	296,638	261,182	53,668	43,335
Change in plan assets				
Fair value of plan assets at January 1	256,872	300,203	–	–
Actual return on plan assets	(12,247)	(25,379)	–	–
Employer contributions	1,626	1,089	4,540	3,374
Participant contributions	69	71	539	551
Settlements	(375)	(1,924)	–	–
Exchange rate changes	3,580	(2,076)	–	–
Benefits paid	(15,093)	(15,112)	(5,079)	(3,925)
Fair value of plan assets at December 31	234,432	256,872	–	–
Reconciliation of funded status				
Funded status at December 31	(62,206)	(4,310)	(53,668)	(43,335)
Unrecognized actuarial (gain) loss	87,259	35,809	20,178	10,505
Unrecognized transition asset	(6,649)	(9,091)	–	–
Unrecognized prior service cost	6,559	6,956	–	–
Net plan asset (liability) recognized	$ 24,963	29,364	(33,490)	(32,830)
Amounts recognized in the Consolidated Balance Sheets at December 31				
Prepaid benefit asset	$ 47,070	45,454	–	–
Accrued benefit liability	(26,660)	(17,310)	(33,490)	(32,830)
Intangible asset	2,472	1,220	–	–
Accumulated other comprehensive loss*	2,081	–	–	–
Net plan asset (liability) recognized	$ 24,963	29,364	(33,490)	(32,830)

*Before reduction for associated deferred taxes of $729.

At December 31, 2002, a minimum pension liability adjustment was required for certain of the Company's domestic plans. For these plans, accumulated benefit obligations exceeded the fair value of plan assets by $15,699,000, compared with a net liability recognized in the balance sheet of $12,001,000. After reductions for amounts charged to intangible assets of $2,081,000 and associated deferred income taxes of $729,000, a charge to accumulated other comprehensive loss of $1,352,000 was recorded.

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)	2002	2001	2002	2001	2002	2001
Funded qualified plans where PBO exceeds fair value of plan assets	$ 262,349	28,920	227,360	24,082	217,891	22,730
Unfunded nonqualified and directors' plans where PBO exceeds fair value of plan assets	23,882	14,581	14,582	10,541	–	–
Unfunded postretirement plans	53,668	43,335	33,490	32,830	–	–

The table that follows provides the components of net periodic benefit expense (credit) for each of the three years ended December 31, 2002.

	Pension Benefits			Postretirement Benefits		
(Thousands of dollars)	2002	2001	2000	2002	2001	2000
Service cost	$ 6,721	5,757	5,461	1,287	935	753
Interest cost	18,097	17,370	17,010	3,280	3,009	2,699
Expected return on plan assets	(19,791)	(24,123)	(24,412)	–	–	–
Amortization of prior service cost	778	782	791	–	–	–
Amortization of transitional asset	(2,559)	(2,552)	(2,585)	–	–	–
Recognized actuarial (gain) loss	1,242	(181)	(395)	633	400	234
	4,488	(2,947)	(4,130)	5,200	4,344	3,686
Settlement gain	–	(901)	(1,824)	–	–	–
Net periodic benefit expense (credit)	$ 4,488	(3,848)	(5,954)	5,200	4,344	3,686

Settlement gains in 2001 related to employee reductions from the sale of Canadian pipeline and trucking assets, while 2000 gains were due to voluntary conversion of certain Canadian employees' retirement coverage from the defined benefit pension plan to a defined contribution plan.

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

	Pension Benefits		Postretirement Benefits	
(Thousands of dollars)	**2002**	**2001**	**2002**	**2001**
Benefit obligation at December 31	$ 54,731	49,010	–	–
Fair value of plan assets at December 31	48,428	46,709	–	–
Net plan asset (liability) recognized	(1,464)	73	–	–
Net periodic benefit expense (credit)	1,077	(704)	–	–

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2002 and 2001.

	Pension Benefits		Postretirement Benefits	
	2002	2001	2002	2001
Discount rate	6.56%	7.00%	6.75%	7.25%
Expected return on plan assets	7.81%	8.30%	–	–
Rate of compensation increase	4.52%	4.59%	–	–

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.

For purposes of measuring postretirement benefit obligations at December 31, 2002, the future annual rates of increase in the cost of health care were assumed to be 7.0% for 2003 decreasing 0.5% per year to an ultimate rate of 5.0% in 2007 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, 2002	$ 321	(304)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 2002	2,770	(2,654)

THRIFT PLANS – Most 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 12,417 shares in 2002, 16,136 shares in 2001 and 6,360 shares in 2000. Amounts charged to expense for these plans were $4,159,000 in 2002, $4,061,000 in 2001 and $3,699,000 in 2000.

Note K – 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, 2002 to hedge fluctuations in cash flows of a similar amount of variable rate debt. Interest rate swaps with notional amounts totaling $50,000,000 matured during the second quarter of 2002. The remaining 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, 2002. The variable rate received by the Company under each contract is repriced quarterly. The Company has a risk management control system to monitor interest rate cash flow risk attributable to the Company's outstanding and forecasted debt obligations as well as the offsetting interest rate swaps. The control system involves using analytical techniques, including cash flow sensitivity analysis, to estimate the impact of interest rate changes on future cash flows. The fair value of the effective portions of the interest rate swaps and changes thereto is deferred in Accumulated Other Comprehensive Loss (AOCL) 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, 2002 and 2001, the income effect from cash flow hedging ineffectiveness of interest rates was insignificant. The fair value of the interest rate swaps are estimated using projected Federal funds rates, Canadian overnight funding rates and LIBOR forward curve rates obtained from published indices and counterparties. The estimated fair value approximates the values based on quotes from each of the counterparties.

- *Natural Gas Fuel Price Risks* – The Company purchases natural gas as fuel at its Meraux, Louisiana refinery, and as such, is subject to commodity price risk related to the purchase price of this gas. Murphy has hedged the cash flow risk associated with the cost of a portion of the natural gas it will purchase in 2004 through 2006 by entering into natural gas swap contracts with a total notional volume of 9.2 million British Thermal Units (MMBTU). Under the natural gas swaps, the Company pays a fixed rate averaging $2.78 per MMBTU and receives a floating rate in each month of settlement based on the average NYMEX price for the final three trading days of the month. Murphy has a risk management control system to monitor natural gas price risk attributable both to forecasted natural gas requirements and to Murphy's natural gas swaps. The control system involves using analytical techniques, including various correlations of natural gas purchase prices to future prices, to estimate the impact of changes in natural gas fuel prices on Murphy's cash flows. The fair value of the effective portions of the natural gas swaps and changes thereto is deferred in AOCL 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. For the years ended December 31, 2002 and 2001, the income effect from cash flow hedging ineffectiveness for these controls was insignificant.

- *Natural Gas Sales Price Risks* – The sales price of natural gas produced by the Company is subject to commodity price risk. Murphy has hedged the cash flow risk associated with the sales price for a portion of the natural gas it will produce in the United States and Canada during 2003 by entering into financial contracts known as natural gas swaps and collars. The swaps cover a combined notional volume averaging 24,200 MMBTU equivalents per day and require Murphy to pay the average relevant index (NYMEX or AECO "C") price for each month and receive an average price of $3.76 per MMBTU equivalent. The natural gas collars are for a combined notional volume averaging 26,700 MMBTU equivalents per day and based upon the relevant index prices provide Murphy with an average floor price of $3.24 per MMBTU and an average ceiling price of $4.64 per MMBTU. Murphy has a risk management control system to monitor natural gas price risk attributable both to forecasted natural gas sales prices and to Murphy's hedging instruments. The control system involves using analytical techniques, including various correlations of natural gas sales prices to futures prices, to estimate the impact of changes in natural gas prices on Murphy's cash flows from the sale of natural gas.

The 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 are deferred in AOCL and are subsequently reclassified into Sales and Other Operating Revenue in the income statement in the periods in which the hedged natural gas sales affect earnings. For the years ended December 31, 2002 and 2001, Murphy's earnings were not significantly affected by cash flow hedging ineffectiveness. During 2002, the Company received approximately $6,900,000 for settlement of natural gas swap and collar agreements in Canada that were entered into in early 2002 and matured before the end of the period.

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

- *Crude Oil Sales Price Risks* – The sales price of crude oil produced by the Company is subject to commodity price risk. Murphy has hedged the cash flow risk associated with the sales price for a portion of the crude oil it will produce in the United States and Canada during 2003 by entering into financial contracts known as crude oil swaps. A portion of the swaps cover a notional volume of 22,000 barrels per day of light oil and require Murphy to pay the average of the closing settlement price on the NYMEX for the Nearby Light Crude Futures Contract for each month and receive an average price of $25.30 per barrel. Additionally, there are heavy oil swaps with a notional volume of 10,000 barrels per day that require 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 are deferred in AOCL and are subsequently reclassified into Sales and Other Operating Revenues in the income statement in the periods in which the hedged crude oil sales affect earnings. In the fourth quarter of 2002, cash flow hedging ineffectiveness relating to the crude oil sales swaps reduced Murphy's after-tax earnings by $1,371,000.

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

- *Crude Oil Purchase Price Risks* – Each month, the Company purchases crude oil as the primary feedstock for its U.S. refineries. Prior to April 2000, the Company was a party to crude oil swap agreements that limited the exposure of its U.S. refineries to the risks of fluctuations in cash flows resulting from changes in the prices of crude oil purchases in 2001 and 2002. Under each swap, Murphy would have paid a fixed crude oil price and would have received a floating price during the agreement's contractual maturity period. In April 2000, the Company settled certain of the swaps and entered into offsetting contracts for the remaining swap agreements, locking in a total pretax gain of $7,735,000. 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 2003, the Company expects to reclassify approximately $16,135,000 in net after-tax losses from AOCL 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, 2002 and 2001. 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.

	2002		2001	
(Thousands of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets (liabilities):				
Interest rate swaps	$ (3,829)	(3,829)	(4,269)	(4,269)
Natural gas fuel swaps	12,398	12,398	4,309	4,309
Natural gas sales swaps and collars	(6,405)	(6,405)	842	842
Crude oil sales swaps	(19,871)	(19,871)	–	–
Crude oil purchase swaps	–	–	1,914	1,914
Current and long-term debt	(919,912)	(923,350)	(569,035)	(542,115)

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 L – 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 M – Earnings per Share

The following table reconciles the weighted-average shares outstanding for computation of basic and diluted income per Common share for each of the three years ended December 31, 2002. No difference existed between net income used in computing basic and diluted income per Common share for these years.

(Weighted-average shares outstanding)	2002	2001	2000
Basic method	91,450,836	90,442,944	90,063,330
Dilutive stock options	684,131	739,054	416,082
Diluted method	92,134,967	91,181,998	90,479,412

The computations of diluted earnings per share in the Consolidated Statements of Income did not consider outstanding options of 294,000 shares at year-end 2000 because the effects of these options would have improved the Company's earnings per share. The average exercise price per share of the options not used was $31.49. There were no antidilutive options for the 2002 and 2001 years.

Note N – Other Financial Information

INVENTORIES – Inventories accounted for under the LIFO method totaled $95,825,000 and $90,464,000 at December 31, 2002 and 2001, respectively, and were $129,044,000 and $51,054,000 less than such inventories would have been valued using the FIFO method.

ABANDONMENT AND RECLAMATION COSTS – The cost of future abandonment and reclamation of proved oil and gas properties under current accounting practices has been estimated by the Company's engineers to be approximately $334,000,000 at December 31, 2002. The estimated total expense to be recorded in future years related to these properties is approximately $173,000,000.

ACCUMULATED OTHER COMPREHENSIVE LOSS – At December 31, 2002 and 2001, the components of Accumulated Other Comprehensive Loss were as follows.

(Thousands of dollars)	2002	2001
Foreign currency translation loss	$ (56,984)	(87,862)
Cash flow hedge gains (losses), net	(8,454)	4,553
Minimum pension liability, net	(1,352)	–
Balance at end of year	$ (66,790)	(83,309)

At December 31, 2002, components of the net foreign currency translation loss of $56,984,000 were gains (losses) of $27,369,000 for pounds sterling, $(85,204,000) for Canadian dollars and $851,000 for other currencies. Comparability of net income was not significantly affected by exchange rate fluctuations in 2002, 2001 and 2000. Net gains from foreign currency transactions included in the Consolidated Statements of Income were $792,000 in 2002, $1,406,000 in 2001 and $252,000 in 2000.

CASH FLOW DISCLOSURES – In association with the Beau Canada acquisition, the Company assumed debt of $124,227,000, a nonmonetary transaction excluded from both financing and investing activities in the Consolidated Statement of Cash Flows for the year ended December 31, 2000. Cash income taxes paid were $28,531,000, $135,734,000 and $53,583,000 in 2002, 2001 and 2000, respectively. Interest paid, net of amounts capitalized, was $20,977,000, $12,945,000 and $15,185,000 in 2002, 2001 and 2000, respectively.

Noncash operating working capital (increased) decreased for each of the three years ended December 31, 2002 as follows.

(Thousands of dollars)	2002	2001	2000
Accounts receivable	$(146,760)	207,594	(95,675)
Inventories	(28,196)	(8,393)	(12,197)
Prepaid expenses	1,100	(37,113)	5,794
Deferred income tax assets	662	6,139	(4,196)
Accounts payable and accrued liabilities	135,800	(176,213)	142,228
Current income tax liabilities	13,181	(19,965)	30,048
Net (increase) decrease in noncash operating working capital excluding acquisition of Beau Canada	$ (24,213)	(27,951)	66,002

Note O – 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 decline gradually from $20,500,000 in 2003 to $18,935,000 in 2007. Rental expense for noncancellable operating leases, including contingent payments when applicable, was $32,087,000 in 2002, $23,859,000 in 2001 and $17,425,000 in 2000. 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 $1,323,000 in 2003, $5,292,000 for each of the years 2004 through 2007, and $56,889,000 in later years. 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 $1,489,000 in 2003 through 2007 and $19,355,000 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 $1,435,000 in 2002, $1,805,000 in 2001, and $507,000 in 2000. Commitments for capital expenditures were approximately $623,000,000 at December 31, 2002, including $82,100,000 related to expansion projects at the Meraux refinery; $126,300,000 for costs to develop deepwater Gulf of Mexico fields, including Medusa, Front Runner, and Habanero; $110,200,000 for continued expansion of synthetic oil operations in Canada; and $121,800,000 for future combined work commitments in Malaysia and offshore Nova Scotia. The expansion projects at the Meraux refinery include construction of a hydrocracker unit that will allow the refinery to produce low-sulfur products, an expansion of crude oil processing capacity from 100,000 barrel per day to 125,000 barrels per day and construction of an additional sulfur recovery complex.

Note P – 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, 11 terminals, and approximately 80 service stations for which known or potential obligations for environmental remediation exist. In addition the Company operates or has operated numerous oil and gas fields that may require some form of remediation, which is generally provided for by the Company's abandonment liability. Environmental laws and regulations are described more fully in Management's Discussion and Analysis 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 Company has received notices from the U.S. Environmental Protection Agency (EPA) that it is currently considered a Potentially Responsible Party (PRP) at two Superfund sites. The potential total cost to all parties to perform necessary remedial work at these sites may be substantial. At one site the Company has agreed to pay $8,100 to obtain release from further obligations. The Company's insurance carrier has agreed to reimburse the $8,100. Based on currently available information, the Company believes that it is a *de minimus* party as to ultimate responsibility at the other Superfund site. The Company could be required to bear a pro rata share of costs attributable to nonparticipating PRPs or could be assigned additional responsibility for remediation at the one remaining site or other Superfund sites. The Company does not believe that the ultimate costs to clean-up the two Superfund sites will have a material adverse effect on its net income or cash flows in a future period.

There is the possibility that environmental expenditures could be required at currently unidentified sites, and new or revised regulations could require additional expenditures at known sites. However, based on information currently available to the Company, the amount of future remediation costs incurred at known or currently unidentified sites is not expected to have a material adverse effect on future earnings 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$4.61 billion. The Company believes that the counterclaim is without merit and that the amount of damages sought is frivolous. While the litigation is in its preliminary stages 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.

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, 2002, the Company had contingent liabilities of $12,706,000 under a financial guarantee described in the following paragraph and $27,738,000 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.

An investee Limited Liability Company accounted for at cost has issued $397,070,000 in bonds. The bonds mature in varying amounts between 2003 and 2021. Under the Limited Liability Company Agreement and the First Stage Throughput and Deficiency (T&D) Agreement, the Company is obligated in accordance with its 3.2% ownership to ship crude oil in quantities sufficient for the investee to pay certain of its expenses and obligations, including the investee's long-term debt secured by the T&D agreement, 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, 2002, 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 Q – Common Stock Issued and Outstanding

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2002 is shown below.

(Number of shares outstanding)	2002	2001	2000
At beginning of year	45,331,080	45,045,545	44,997,995
Stock options exercised	491,700	261,200	43,678
Employee stock purchase plans	28,647	24,896	16,855
Restricted stock forfeitures	–	(750)	(12,954)
Two-for-one stock split	45,838,065	–	–
All other	(38)	189	(29)
At end of year	91,689,454	45,331,080	45,045,545

Note R – Subsequent Event (unaudited)

In early 2003, the Company signed a letter of intent to sell its interests in the Ninian and Columba fields in the U.K. for total proceeds of approximately $36,000,000. The transaction should close in the second quarter.

Note S – 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. During 2002, the Company changed its reportable segments to combine U.S. and Canadian refining and marketing operations into one North American segment. Operations for crude oil trading and transportation activities in Canada prior to sale of this operation in 2001 have been 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 $1,147,922,000, $1,005,018,000 and $1,052,760,000 for the years 2002, 2001 and 2000, 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-30, Certain Long-Lived Assets at December 31 exclude investments, noncurrent receivables, deferred tax assets and intangible assets.

Segment Information (Millions of dollars)	Exploration and Production						
	U.S.	Canada	U.K.	Ecuador	Malaysia	Other	Total
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
Year ended December 31, 2000							
Segment income (loss) from continuing operations	$ 43.3	108.1	90.2	21.1	(10.7)	(6.3)	245.7
Revenues from external customers	255.0	278.6	211.5	51.5	–	2.2	798.8
Intersegment revenues	4.8	106.3	11.6	–	–	–	122.7
Interest income	–	–	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–	–	–
Income tax expense (benefit)	23.3	66.3	56.2	–	–	–	145.8
Significant noncash charges (credits)							
Depreciation, depletion, amortization	47.6	70.0	41.7	6.8	.4	.1	166.6
Impairment of properties	21.0	6.9	–	–	–	–	27.9
Provisions for major repairs	–	3.3	–	–	–	–	3.3
Amortization of undeveloped leases	7.7	6.4	–	–	–	–	14.1
Deferred and noncurrent income taxes	(5.1)	55.6	(1.5)	–	–	1.0	50.0
Additions to property, plant, equipment	69.9	425.5	24.6	12.3	8.1	.8	541.2
Total assets at year-end	413.6	1,131.1	261.7	79.8	9.3	7.1	1,902.6

Geographic Information (Millions of dollars)	Certain Long-Lived Assets at December 31						
	U.S.	Canada	U.K.	Ecuador	Malaysia	Other	Total
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
2000	764.8	1,063.2	297.1	59.0	8.7	5.9	2,198.7

Segment Information (Continued) (Millions of dollars)	Refining and Marketing North America	Refining and Marketing U.K.	Refining and Marketing Total	Corp. & Other	Consolidated
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	–	–	–	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
Year ended December 31, 2000					
Segment income (loss) from continuing operations	$ 31.5	23.0	54.5	(1.7)	298.5
Revenues from external customers	2,425.2	409.3	2,834.5	24.9	3,658.2
Intersegment revenues	1.6	–	1.6	–	124.3
Interest income	–	–	–	21.7	21.7
Interest expense, net of capitalization	–	–	–	16.3	16.3
Income tax expense (benefit)	20.1	11.3	31.4	(21.2)	156.0
Significant noncash charges (credits)					
Depreciation, depletion, amortization	35.3	5.6	40.9	3.4	210.9
Impairment of properties	–	–	–	–	27.9
Provisions for major repairs	17.6	1.8	19.4	.1	22.8
Amortization of undeveloped leases	–	–	–	–	14.1
Deferred and noncurrent income taxes	5.2	1.2	6.4	7.0	63.4
Additions to property, plant, equipment	141.4	12.4	153.8	11.4	706.4
Total assets at year-end	796.0	222.6	1,018.6	213.2	3,134.4

Geographic Information (Millions of dollars)	Revenues from External Customers for the Year U.S.	U.K.	Canada	Ecuador	Other	Total
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
2000	2,668.7	625.9	309.9	51.5	2.2	3,658.2

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.

Oil reserves in Ecuador are derived from a participation agreement covering Block 16 in the Amazon region. Oil reserves associated with the participation agreement in Ecuador totaled 32.9 million barrels at December 31, 2002. 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 15.3 million barrels at December 31, 2002.

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 2, 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. Results of oil and gas producing activities include certain nonrecurring items that are reviewed in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 10 and 11 of this Form 10-K report, and should be considered in conjunction with the Company's overall performance.

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 2002 crude oil prices used for this calculation were $30.07 per barrel for the United States, $25.27 for Canadian light, $18.91 for Canadian heavy, $30.18 for Canadian offshore, $30.03 for the United Kingdom, $20.98 for Ecuador and $30.56 for Malaysia. Average year-end 2002 natural gas prices used were $4.69 per MCF for the United States, $3.71 for Canada and $3.16 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, 2002.

Schedule 1 – Estimated Net Proved Oil Reserves

	Crude Oil, Condensate and Natural Gas Liquids					
(Millions of barrels)	United States*	Canada	United Kingdom	Ecuador	Malaysia	Total
Proved						
December 31, 1999	34.1	53.7	56.9	37.0	–	181.7
Revisions of previous estimates	(1.7)	4.5	1.8	3.6	–	8.2
Purchases	–	11.7	–	–	–	11.7
Extensions and discoveries	15.3	4.0	–	2.6	–	21.9
Production	(2.4)	(8.4)	(7.7)	(2.3)	–	(20.8)
Sales	–	(1.6)	–	–	–	(1.6)
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
Proved Developed						
December 31, 1999	11.7	26.6	34.1	21.2	–	93.6
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

*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.

Schedule 2 – Estimated Net Proved Natural Gas Reserves

(Billions of cubic feet)	United States*	Canada	United Kingdom	Total
Proved				
December 31, 1999	427.3	125.8	38.5	591.6
Revisions of previous estimates	(41.9)	(5.0)	.3	(46.6)
Purchases	5.4	163.3	–	168.7
Extensions and discoveries	31.2	40.1	–	71.3
Production	(53.0)	(27.0)	(4.0)	(84.0)
Sales	–	(3.6)	–	(3.6)
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
Proved Developed				
December 31, 1999	284.8	111.3	32.9	429.0
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

*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.

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-38.

Synthetic Oil Proved Reserves (Millions of barrels)	
At December 31, 1999	120.5
At December 31, 2000	125.0
At December 31, 2001	131.0
At December 31, 2002	136.2

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, 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
Expenditures capitalized	$ 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
Expenditures capitalized	$ 222.8	259.8	17.9	9.0	9.6	–	519.1
Year Ended December 31, 2000							
Property acquisition costs							
Unproved	$ 19.2	25.1	–	–	–	–	44.3
Proved	1.5	2.9	–	–	–	–	4.4
Total	20.7	28.0	–	–	–	–	48.7
Exploration costs	96.2	32.1	5.2	.1	18.4	4.7	156.7
Development costs	20.3	113.8	22.5	12.2	–	–	168.8
Total capital expenditures	137.2	173.9	27.7	12.3	18.4	4.7	374.2
Beau Canada property acquisition							
Unproved	–	18.2	–	–	–	–	18.2
Proved	–	241.8	–	–	–	–	241.8
Total	–	260.0	–	–	–	–	260.0
Charged to expense							
Dry hole expense	56.7	5.7	1.7	–	1.3	.6	66.0
Geophysical and other costs	10.6	21.2	1.4	–	9.0	3.3	45.5
Total charged to expense	67.3	26.9	3.1	–	10.3	3.9	111.5
Expenditures capitalized	$ 69.9	407.0	24.6	12.3	8.1	.8	522.7

[1]Excludes $.5 million in 2002 and $3.4 million in 2001 related to discontinued operations. No costs were incurred in 2000.
[2]Excludes costs incurred for the Company's 5% interest in Synthetic Oil operations in Canada. Total costs incurred were $61.5 million in 2002, $27.2 million in 2001 and $18.5 million in 2000.

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, 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
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 2002 and 2001. Income from discontinued operations was $14.0 million in 2002 and $2.5 million in 2001.

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

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

(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Malaysia	Other	Subtotal	Synthetic Oil – Canada	Total
Year Ended December 31, 2000									
Revenues									
Crude oil and natural gas liquids									
Transfers to consolidated operations	$ –	68.4	11.6	–	–	–	80.0	37.9	117.9
Sales to unaffiliated enterprises	53.2	125.5	203.0	52.2	–	–	433.9	53.6	487.5
Natural gas									
Transfers to consolidated operations	4.8	–	–	–	–	–	4.8	–	4.8
Sales to unaffiliated enterprises	206.6	99.0	7.8	–	–	–	313.4	–	313.4
Total oil and gas revenues	264.6	292.9	222.4	52.2	–	–	832.1	91.5	923.6
Other operating revenues	(4.8)	.5	.7	(.7)	–	2.2	(2.1)	–	(2.1)
Total revenues	259.8	293.4	223.1	51.5	–	2.2	830.0	91.5	921.5
Costs and expenses									
Production expenses	36.1	55.0	29.1	15.5	–	–	135.7	40.4	176.1
Exploration costs charged to expense	67.3	26.9	3.1	–	10.3	3.9	111.5	–	111.5
Undeveloped lease amortization	7.7	6.4	–	–	–	–	14.1	–	14.1
Depreciation, depletion and amortization	47.6	62.5	41.7	6.8	.4	.1	159.1	7.5	166.6
Impairment of properties	21.0	6.9	–	–	–	–	27.9	–	27.9
Selling and general expenses	13.5	4.8	2.8	.3	–	4.5	25.9	.1	26.0
Loss on transportation and other disputed contractual items	–	–	–	7.8	–	–	7.8	–	7.8
Total costs and expenses	193.2	162.5	76.7	30.4	10.7	8.5	482.0	48.0	530.0
	66.6	130.9	146.4	21.1	(10.7)	(6.3)	348.0	43.5	391.5
Income tax expense	23.3	49.2	56.2	–	–	–	128.7	17.1	145.8
Results of operations*	$ 43.3	81.7	90.2	21.1	(10.7)	(6.3)	219.3	26.4	245.7

*Excludes discontinued operations, corporate overhead and interest and the cumulative effect of an accounting change. Income from discontinued operations was $7.0 million in 2000.

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, 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
December 31, 2000							
Future cash inflows	$	3,479.9	2,860.4	1,209.4	725.5	–	8,275.2
Future development costs		(321.8)	(97.3)	(55.0)	(72.2)	–	(546.3)
Future production and abandonment costs		(479.2)	(615.5)	(378.8)	(320.4)	–	(1,793.9)
Future income taxes		(935.6)	(673.4)	(294.8)	(95.6)	–	(1,999.4)
Future net cash flows		1,743.3	1,474.2	480.8	237.3	–	3,935.6
10% annual discount for estimated timing of cash flows		(620.4)	(456.1)	(153.3)	(102.0)	–	(1,331.8)
Standardized measure of discounted future net cash flows	$	1,122.9	1,018.1	327.5	135.3	–	2,603.8

[1]Includes discounted future net cash flows from discontinued operations of $1.9 million and $47.8 million at December 31, 2001 and 2000, respectively.

[2]Excludes discounted future net cash flows from synthetic oil of $411 million at December 31, 2002, $188 million at December 31, 2001 and $441.5 million at December 31, 2000.

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

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

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

(Millions of dollars)	2002	2001	2000
Net changes in prices, production costs and development costs	$ 2,480.2	(2,636.9)	946.8
Sales and transfers of oil and gas produced, net of production costs	(672.9)	(655.4)	(709.9)
Net change due to extensions and discoveries	238.8	691.6	544.4
Net change due to purchases and sales of proved reserves	(150.9)	19.3	519.2
Development costs incurred	304.3	308.7	156.6
Accretion of discount	202.5	390.6	229.3
Revisions of previous quantity estimates	(223.2)	1.4	(73.7)
Net change in income taxes	(824.8)	703.3	(659.9)
Net increase (decrease)	1,354.0	(1,177.4)	952.8
Standardized measure at January 1	1,426.4	2,603.8	1,651.0
Standardized measure at December 31	$ 2,780.4	1,426.4	2,603.8

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, 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]	(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
December 31, 2001									
Unproved oil and gas properties	$ 128.6	130.6	.3	–	.4	3.5	263.4	–	263.4
Proved oil and gas properties	1,673.8	1,326.7	794.8	227.9	15.1	–	4,038.3	204.0	4,242.3
Gross capitalized costs	1,802.4	1,457.3	795.1	227.9	15.5	3.5	4,301.7	204.0	4,505.7
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	(23.0)	(33.8)	(.2)	–	–	(3.5)	(60.5)	–	(60.5)
Proved oil and gas properties[1]	(1,289.7)	(469.3)	(612.6)	(166.3)	–	–	(2,537.9)	(42.3)	(2,580.2)
Net capitalized costs[2]	$ 489.7	954.2	182.3	61.6	15.5	–	1,703.3	161.7	1,865.0

[1]Does not include reserve for dismantlement costs of $160.5 million in 2002 and $160.8 million in 2001.
[2]2001 net capitalized costs include $8.6 million related to discontinued operations.

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, 2002[1]					
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[2,3]					
High	48.18	49.70	43.72	46.10	49.70
Low	38.25	40.95	32.47	38.15	32.47
Year Ended December 31, 2001[1]					
Sales and other operating revenues	$ 961.8	1,045.5	992.2	744.5	3,744.0
Income from continuing operations before income taxes	153.9	246.2	68.6	33.4	502.1
Income from continuing operations	96.4	162.1	41.0	28.9	328.4
Discontinued operations	1.4	.5	.7	(.1)	2.5
Net income	97.8	162.6	41.7	28.8	330.9
Income per Common share – basic[3]					
Income from continuing operations	1.06	1.80	.45	.32	3.63
Discontinued operations	.02	–	.01	–	.03
Net income	1.08	1.80	.46	.32	3.66
Income per Common share – diluted[3]					
Income from continuing operations	1.06	1.78	.45	.31	3.60
Discontinued operations	.02	–	.01	–	.03
Net income	1.08	1.78	.46	.31	3.63
Cash dividends per Common share[3]	.1875	.1875	.1875	.1875	.75
Market Price of Common Stock[2,3]					
High	34.50	43.92	42.85	42.49	43.92
Low	27.62	33.57	33.27	34.00	27.62

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

[1]The effect of nonrecurring gains (losses) on quarterly net income are reviewed in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 10 and 11 of this Form 10-K report. Quarterly totals, in millions of dollars, and the effect per Common share of these special items are shown in the following table.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2002					
Quarterly totals from continuing operations	$ –	–	7.9	(14.6)	(6.7)
Quarterly totals from discontinued operations	–	–	–	10.6	10.6
Per Common share from continuing operations – basic	–	–	.09	(.16)	(.07)
Per Common share from discontinued operations – basic	–	–	.09	(.16)	(.07)
Per Common share from continuing operations – diluted	–	–	–	.12	.12
Per Common share from discontinued operations – diluted	–	–	–	.12	.12
2001					
Quarterly totals	$ –	67.6	–	–	67.6
Per Common share – basic[3]	–	.75	–	–	.75
Per Common share – diluted[3]	–	.74	–	–	.74

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

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

(Millions of dollars)	Balance at January 1	Charged to Expense	Deductions	Other*	Balance at December 31
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
2000					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 8.3	2.1	(.2)	–	10.2
Deferred tax asset valuation allowance	57.4	3.6	–	–	61.0
Included in liabilities:					
Accrued major repair costs	22.1	22.8	(10.1)	(.5)	34.3

*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
deepwater
offshore location in greater than 600 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
green fuels or clean fuels
low-sulfur content gasoline and diesel products
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

Principal Offices

- El Dorado, Arkansas
- New Orleans, Louisiana
- Houston, Texas
- Calgary, Alberta, Canada
- St. Albans, Hertfordshire, England
- Kuala Lumpur, Malaysia

Corporate Information

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(870) 862-6411

Stock Exchange Listings
Trading Symbol: MUR
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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 14, 2003, 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:

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