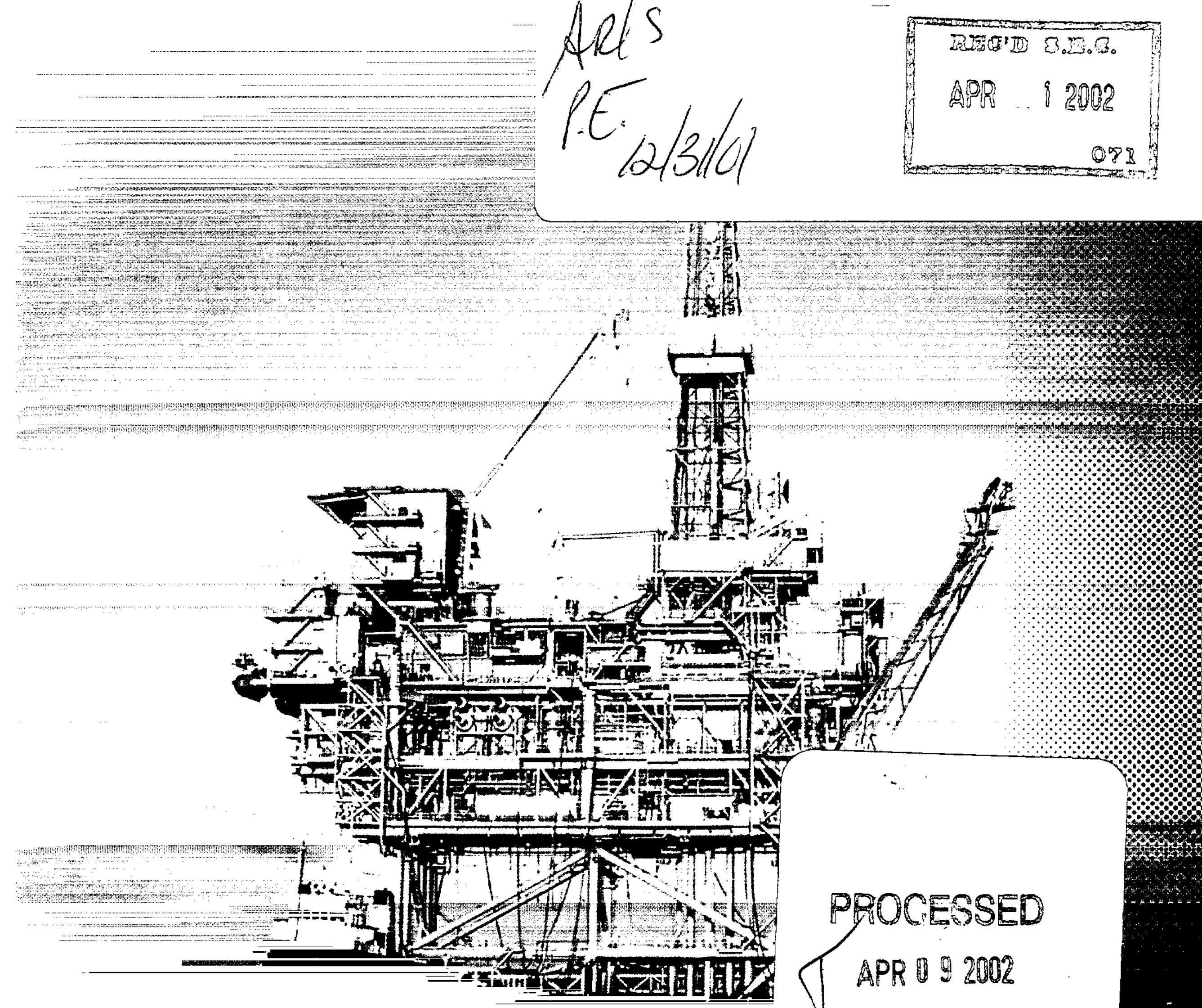
THE 2001



MURPHY OIL CORPORATION

Annual Report

MURPHY
OIL CORPORATION

HIGHLIGHTS

FINANCIAL

(Thousands of dollars except per share data)	2001	2000	1999
For the Year*			
Revenues	**$ 4,478,509**	4,639,165	2,756,441
Net income	**330,903**	296,828	119,707
Cash dividends paid	**67,826**	65,294	62,950
Capital expenditures	**864,440**	557,897	386,605
Net cash provided by operating activities	**635,704**	747,751	341,711
Average Common shares outstanding – diluted	**45,590,999**	45,239,706	45,030,225
At End of Year			
Working capital	**$ 38,604**	71,710	105,477
Net property, plant and equipment	**2,525,807**	2,184,719	1,782,741
Total assets	**3,259,099**	3,134,353	2,445,508
Long-term debt	**520,785**	524,759	393,164
Stockholders' equity	**1,498,163**	1,259,560	1,057,172
Per Share of Common Stock*			
Net income – diluted	**$ 7.26**	6.56	2.66
Cash dividends paid	**1.50**	1.45	1.40
Stockholders' equity	**33.05**	27.96	23.49

*Includes special items that are detailed in Management's Discussion and Analysis, page 9 of the attached Form 10-K report.

OPERATING

For the Year	2001	2000	1999
Net crude oil and gas liquids produced – barrels a day	**67,355**	65,259	66,083
United States	**5,763**	6,663	8,461
Canada	**36,059**	31,296	29,980
Other International	**25,533**	27,300	27,642
Net natural gas sold – thousands of cubic feet a day	**281,235**	229,412	240,443
United States	**115,527**	144,789	171,762
Canada	**152,583**	73,773	56,238
United Kingdom	**13,125**	10,850	12,443
Crude oil refined – barrels a day	**167,199**	165,820	143,204
United States	**140,214**	137,313	115,812
United Kingdom	**26,985**	28,507	27,392
Petroleum products sold – barrels a day	**205,318**	179,515	159,042
United States	**174,256**	149,469	126,195
United Kingdom	**31,062**	29,903	32,251
Canada	**–**	143	596

LETTER TO THE SHAREHOLDERS

Dear Fellow Shareholder:

Claiborne P. Deming
President and CEO

While uncertainty has always been a part of the oil industry, it has been nearly a decade since the world has encountered both the political and economic uncertainties we face today. Specifically, since the attacks of September 11, global recession and worldwide political instability have significantly eroded demand for energy. Despite this unsettling backdrop, Murphy remains committed to internally-generated, profitable growth. By emphasizing entrepreneurial values, we transformed your Company from a steady, domestic integrated oil company to a growth vehicle with three world-class initiatives – deepwater Gulf of Mexico, Malaysia and the Wal-Mart program. Murphy's share price soared in 2001, posting a 40% increase, among the best in the industry. Income levels, robust in the first half of the year, slowed with the terrorist attacks. Still, income before special items was a healthy $263 million, second only to the record set in 2000, and included $188 million for Exploration and Production operations and a record $89 million for Refining and Marketing.

The year 2002 brings new challenges as natural gas prices are extremely weak and oil demand is tied to a worldwide economy that remains sluggish, yet shows signs of awakening. Your Company will experience significant production growth in 2002 as the Terra Nova field (12%) off the east coast of Canada, which came on stream January 20, should reach gross production levels of 125,000 barrels of oil a day by the end of the year. Future growth looks equally promising for

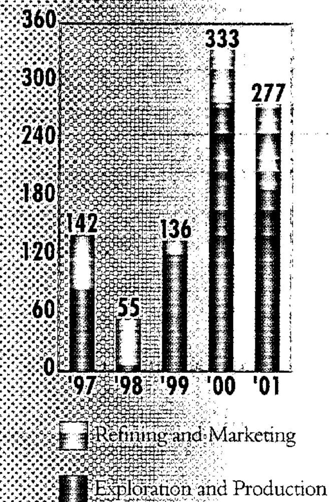
Emphasizing entrepreneurial values, we transformed your Company from a steady, domestic integrated oil company to a growth vehicle with three world-class initiatives.

Murphy as our deepwater Gulf of Mexico discoveries begin producing, the Syncrude expansion is completed, Ecuadorian production increases once the new oil pipeline is built and our Malaysian shallow-water discovery at West Patricia is

Income Contribution by Function

(millions of dollars)

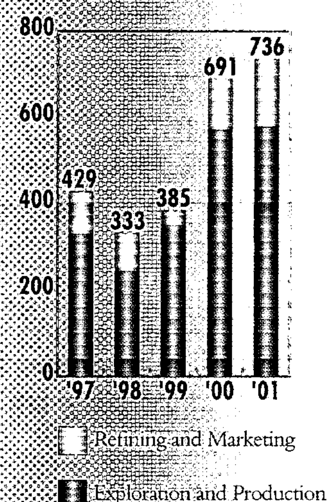
Excludes special items and Corporate activities

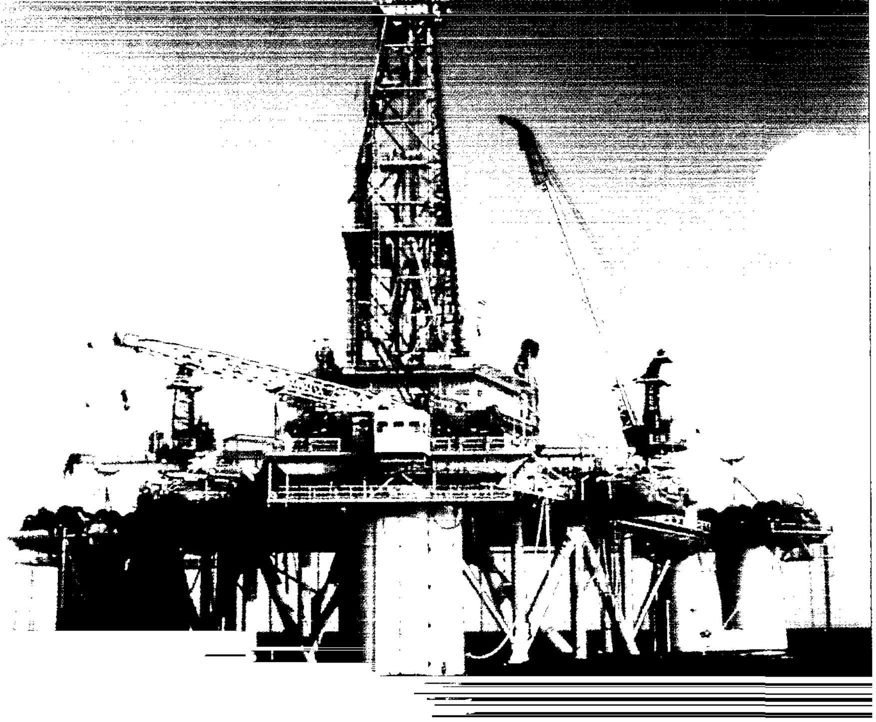


Cash Flow by Function

(millions of dollars)

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



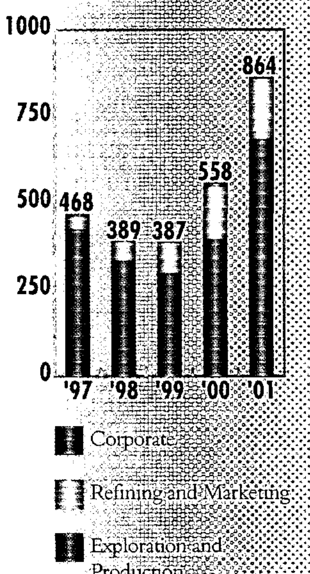


During 2001, Murphy made its largest deepwater Gulf of Mexico discovery to date at Front Runner.

Upstream remains the principal growth vehicle of the Murphy enterprise, with the deepwater Gulf of Mexico being the cornerstone of our exploration strategy.

Capital Expenditures by Function

(millions of dollars)



developed. Our challenge, naturally, is to deliver this growth, even in these times of economic uncertainty.

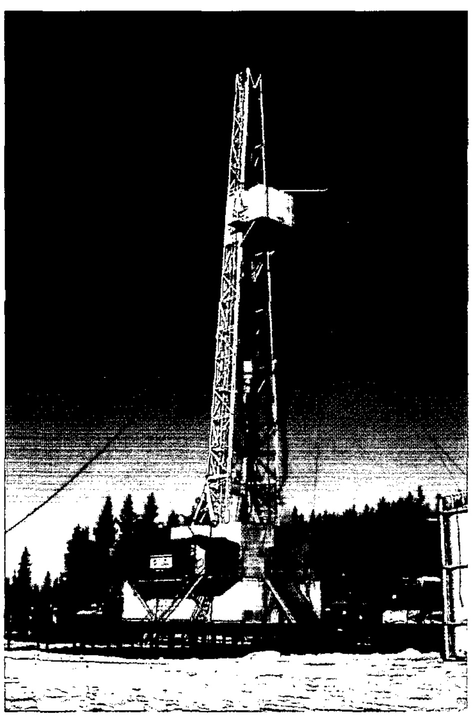
Upstream remains the principal growth vehicle of the Murphy enterprise, with the deepwater Gulf of Mexico being the cornerstone of our exploration strategy. Since 1997 Murphy has acquired 136 deepwater blocks, drilled 15 exploration wells, and made six discoveries, positioning us as one of the leaders in deepwater. Two of Murphy's initial deepwater discoveries are currently in the development stage. A floating spar facility capable of handling production up to 40,000 barrels a day of oil and 110 million cubic feet a day of natural gas is under construction for the Medusa field (60%), located in Mississippi Canyon Blocks 538 and 582. Installation of the facility is scheduled for October 2002 and first oil is expected to flow two months later. At peak, Medusa will net 25,000 barrels a day of oil equivalent production to Murphy. At Habanero (33.75%), located in Garden Banks Block 341, development work in the field is ongoing as we prepare for its subsea tieback to an existing host facility in mid-2003. Habanero's peak production will also add a meaningful contribution to Murphy at approximately 15,000 barrels of oil equivalent a day.

Exploration and Production

(Thousands of dollars)	2001	2000	1999
Income contribution before special items	$ **188,107**	278,347	121,182
Total assets	**2,151,049**	1,902,618	1,497,770
Capital expenditures	**683,448**	392,732	295,958
Crude oil and liquids produced – barrels a day	**67,355**	65,259	66,083
Natural gas sold – MCF a day	**281,235**	229,412	240,443
Net hydrocarbons produced – oil equivalent barrels a day	**114,228**	103,494	106,157
Net proved hydrocarbon reserves – thousands of oil equivalent barrels	**501,200**	442,300	400,800

During 2001, Murphy added three deepwater Gulf of Mexico discoveries, with successes at Murphy-operated Front Runner (37.5%), Front Runner South (37.5%) and Seventeen Hands (37.5%). Front Runner, located in Garden Banks Block 338, is the largest of our deepwater discoveries to date. After completing the initial discovery well in March, we began appraisal activities and drilled two additional successful wells. Quickly following the success at Front Runner, Murphy made a discovery on a separate structure at Front Runner South in Garden Banks Block 339. This discovery is a strong complement to Front Runner, and the two discoveries will be developed jointly to maximize value. The Front Runner development will require a stand-alone floating production system, and preparations are now under way to sanction the facility design and construction in the first quarter of 2002. While the production facility will likely be similar to Medusa, the Front Runner spar will be larger, capable of handling up to 60,000 barrels of oil and 110 million cubic feet of natural gas per day. The preliminary target date for first production from Front Runner is in the first half of 2004. Encouraged by the success achieved at Front Runner and Front Runner South, Murphy aggressively worked to tie up other acreage in the area with the hope of extending the successes achieved in 2001 with additional discoveries. As a result of this effort, we acquired 11 blocks to the south of Front Runner at the March 2001 lease sale. Murphy and its partners have currently identified multiple prospects on these blocks, which have the potential to make this mini-basin a prolific producing area for Murphy for many years. Drilling on these adjacent blocks commences during the first quarter of 2002 beginning with the Murphy-operated Quatrain prospect (37.5%) located in Garden Banks Block 382.

During 2001, Murphy added three deepwater Gulf of Mexico discoveries.

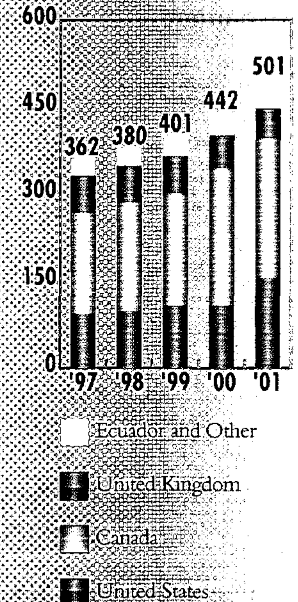


Over the past two years, Murphy has nearly tripled their Canadian gas production due to the prolific Ladyfern field.

We also discovered natural gas at our Seventeen Hands prospect during 2001, adding to an already impressive year of exploratory drilling for Murphy in the deepwater Gulf of Mexico. Located in Mississippi Canyon Block 299, Seventeen Hands is sized at an estimated 50 to 100 billion cubic feet of natural gas and

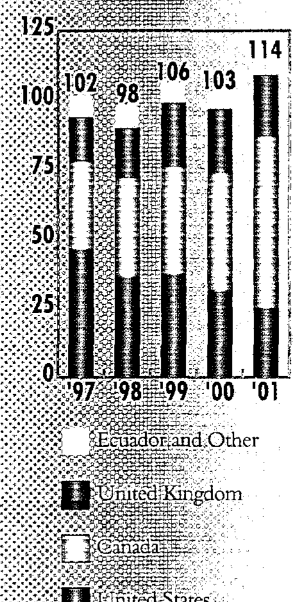
Estimated Net Proved Hydrocarbon Reserves

(millions of oil equivalent barrels)



Net Hydrocarbons Produced

(thousands of oil equivalent barrels a day)

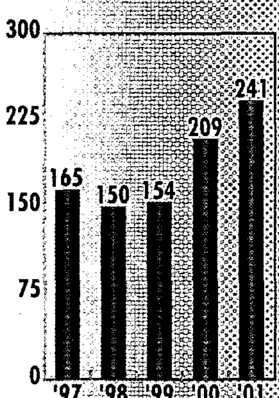


The Terra Nova field, placed onstream in January 2002, will contribute a net 15,000 barrels per day to Murphy's production for several years.

Canada has been an integral focus of corporate expansion for Murphy over the past decade.

Hydrocarbon Production Replacement

(percent of production)

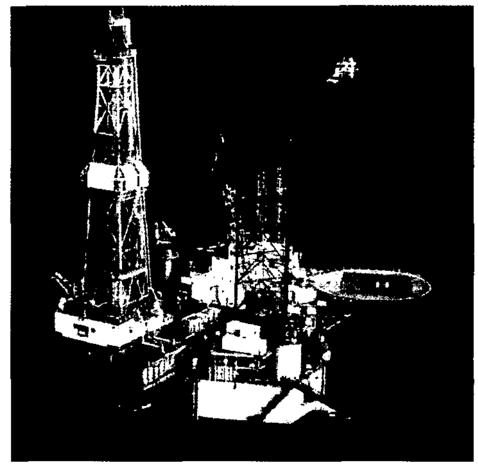


we are currently performing engineering studies to determine the feasibility of a subsea tieback to a host facility.

With Murphy-owned infrastructure in place as host facilities, such as at Medusa and Front Runner, the opportunity to tie back smaller satellite discoveries will exist, thereby enhancing our fields' overall project return and value. Murphy intends to drill four to five deepwater exploration wells a year, targeting various play types with higher working interests and typically serving as operator. Planned wells include those mentioned in the Front Runner area, as well as the Sport of Kings prospect (37.5%) located in Mississippi Canyon Block 734 near the super-giant Thunder Horse billion-barrel discovery.

Canada has been an integral focus of corporate expansion for Murphy over the past decade. Beginning in the early 1990s, working interest positions were acquired in a portfolio of oil projects – Hibernia (6.5%), Terra Nova (12%) and Syncrude (5%) – that are now providing Murphy with a solid production base and significant cash flow. Located in the Jeanne d'Arc basin, Hibernia currently produces approximately 170,000 to 180,000 gross barrels per day of oil, which nets Murphy about 11,000 barrels per day. Improved recoveries at Hibernia have the potential to continue to drive the field's reserves toward one billion barrels.

Terra Nova will add 15,000 net barrels a day of oil production to our slate by the end of the year. The initial exploratory well in the previously untested Far East flank of Terra Nova encountered the third longest oil column in the field. Although additional wells are necessary before the reserve impact can be established, the news is encouraging.



The West Patricia discovery will be Murphy's first shallow-water development in Malaysia, with production expected in early 2003.

Syncrude is recognized as Canada's largest source of crude oil production, combining mining, extraction and upgrading technologies to produce a light, sweet synthetic crude. At Syncrude, phase two of a five-phase expansion was completed in 2000 with the opening of the Aurora mine. Phase three was approved in June 2001 and includes a second mining train at Aurora and expansion of upgrading facilities, which will improve the quality of total production and give this operation a competitive cost advantage.

Going forward, Murphy's Canadian exploration remains focused on natural gas in the Western Sedimentary Basin while seeking high potential wildcat opportunities on the East Coast. In Western Canada, Murphy will continue to focus on the Devonian Reefs area, but will remain active in the Foothills and West Central Alberta.

Improved recoveries at Hibernia have the potential to continue to drive the field's reserves toward one billion barrels.

Murphy's position in the Canadian natural gas market, an area targeted by many companies over the past few years, has dramatically improved with our major discovery at Ladyfern (63%) and the November 2000 acquisition of Beau Canada Exploration Ltd.

In the Ladyfern area, Murphy currently produces in excess of 100 million net cubic feet per day of natural gas. Unfortunately, a steep decline in production will commence in mid-2002. Large inventories of acreage and seismic data in this play have been acquired and a number of prospects will be tested over the next two years. Should further discoveries occur at nearby prospects, our Ladyfern infrastructure will be available to process this production, thereby providing the Company with another source of revenue from the area.

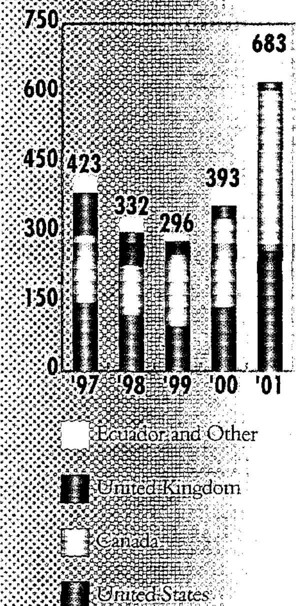
Murphy achieved success this year with a number of modest discoveries in the Peace River Arch, West Central Alberta and the Devonian Reefs, which offset declines in our current base of production.

Starting in 1998, Murphy began a concentrated effort to gain exploration exposure in the frontier natural gas region off Canada's eastern coast. We have now attained a working interest in approximately 12 million gross acres, covering several known play types in a variety of water depths around Sable Island and in the Laurentian Channel.

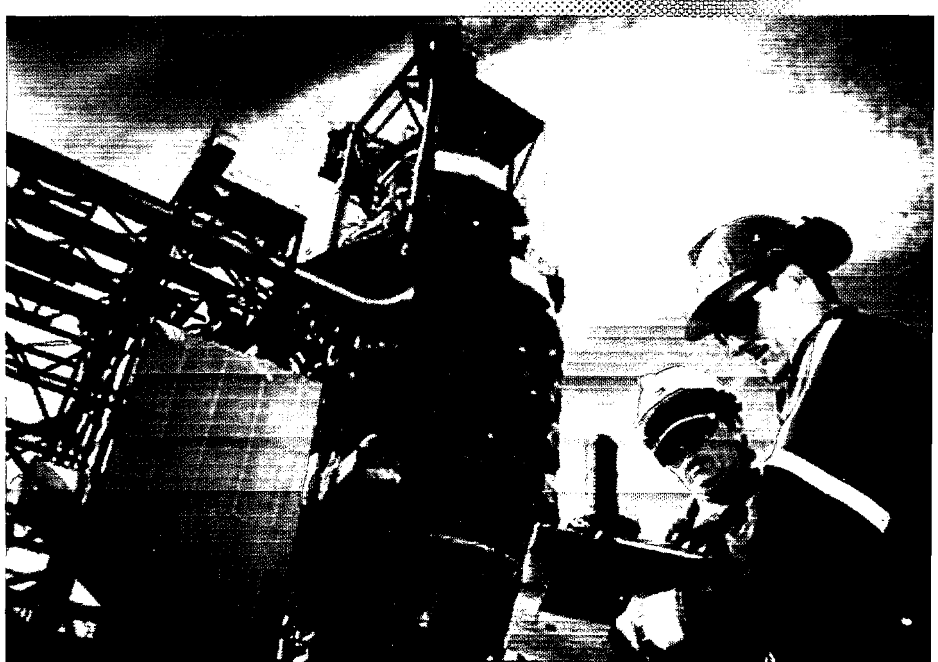
Exploratory drilling on the Scotian Shelf, near Sable Island, began in the fourth quarter of 2001. Although it is too early to draw any conclusions from the program, the initial results have not been encouraging. We are currently drilling to test a completely different objective at the deepwater Annapolis prospect (19%), which has the potential to hold over one trillion cubic feet of natural gas. If we have exploration success from this well,

Capital Expenditures – Exploration and Production

(millions of dollars)

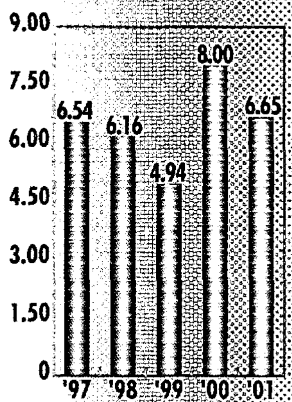


Ongoing expansion at Syncrude will continue to add further production capacity to Murphy's synthetic crude oil operation.



Worldwide Finding and Development Costs

(dollars per oil equivalent barrel)



In 2001, Murphy shot seismic over deepwater Blocks K and H in Malaysia in preparation for an active drilling program commencing in March 2002.

we will build a further exploration program during 2002 in this area. If the well is unsuccessful, we retain a large acreage inventory with a modest ongoing commitment. Other companies will begin drilling in the area in 2002 and their results will be utilized to assess our future drilling opportunities. Blocks K and H gives Murphy access to over 6.4 million undrilled acres in one of the more promising deepwater plays in the world. An extensive 3D seismic program over both blocks was undertaken in 2001 to more specifically identify exploration targets in preparation for drilling.

The combination of Blocks K and H gives Murphy access to over 6.4 million undrilled acres in one of the more promising deepwater plays in the world.

Murphy's frontier exploration program centers on the Malaysian shelf and deepwater. Active exploration during 2001 resulted in a discovery at West Patricia on Block SK 309 (85%). Drilled in 110 feet of water, the initial discovery well encountered hydrocarbons at multiple levels and flowed 2,900 barrels a day of 37-degree gravity crude oil from a single zone between the depths of 2,963 and 3,117 feet. The discovery has now been appraised and the field will be sanctioned for development in the first quarter 2002. Gross recoverable reserves are expected to be in the range of 30 million barrels, and first production of at least 10,000 barrels a day is planned for the first quarter of 2003.

Substantial single-field oil and natural gas potential will be tested offshore Sabah in deepwater Block K (80%) beginning in the first quarter of 2002. We plan a drilling program of two to four wells on the block this year. Also of note, Murphy completed a farm-in agreement during 2001 to acquire an 80% interest in Block H, which is contiguous to Block K but in more shallow water. The combination of

Other frontier areas for Murphy include the United Kingdom and Ecuador. In the United Kingdom, we plan to exercise continued diligence in maximizing value from our producing assets that currently provide significant cash flow to fund other more value accretive projects elsewhere.

In Ecuador, the heavy crude pipeline that will be used to evacuate production from the Amazon Basin to the coast is under construction, with planned start-up in mid-2003. The new pipeline will permit our 20%-owned Block 16 gross production to rise to as high as 100,000 barrels a day. Current production is approximately 25,000 barrels a day and is restricted by lack of available capacity in the existing pipeline.

At year-end 2001, Murphy had crude oil and natural gas reserves of 501 million barrels of oil equivalent and during 2001 more than replaced production for the eleventh consecutive year. Going forward, both reserves and production levels should continue to post steady increases as recent exploratory successes translate into further development projects.

Also, Murphy's extensive acreage inventory in western Canada, the deepwater Gulf of Mexico and Malaysia will continue to be explored and has the potential to significantly impact our company.

On the Downstream side, by aggressively building stations on the parking lots of Wal-Mart Supercenters, Murphy continues its transformation into the leading hypermarket gasoline retailer in the United States. Importantly, our 21-state marketing area in the southern and midwestern U.S. places us in the center of Wal-Mart's strongest market concentration. During 2001, we constructed 111 stations and ended the year with a total of 387 operating sites. We also achieved record gasoline sales volume during the year with the stations averaging well over 200,000 gallons a month. Going forward, we plan to construct about 110 stations a year as we open stations on pace with Wal-Mart Supercenter "Grand Openings" in our marketing area. The expansion of this program is important because the Wal-Mart initiative provides one of our best hedges against low oil prices. We intend to use this new advantage to attempt to match the full-cycle capital efficiency of the supermajors – something rare for a company our size. Simply put, our goal is more pumps, more stations and more customers.

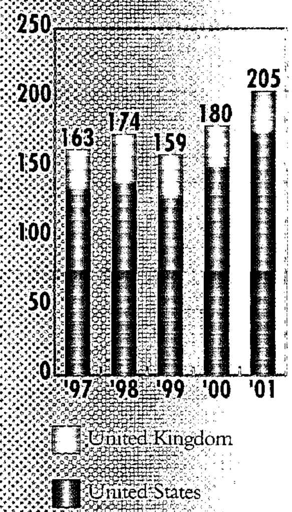
Murphy continues its transformation into the leading hypermarket gasoline retailer in the United States.

In the first quarter of 2002, Murphy and Wal-Mart announced that Murphy would expand its Wal-Mart relationship into Canada. We expect to build up to 20 stations a year in Canada from the east to the west coast.

Murphy's collaboration with Wal-Mart continues to expand with the addition of Canada to their marketing territory.

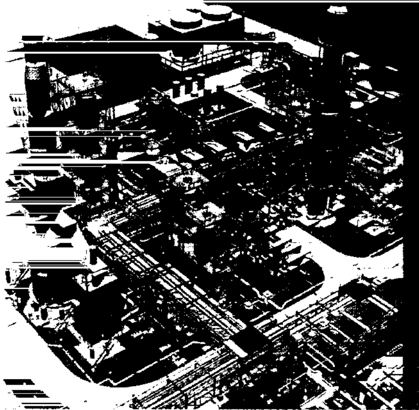
Refined Products Sold

(thousands of barrels a day)



Refining and Marketing

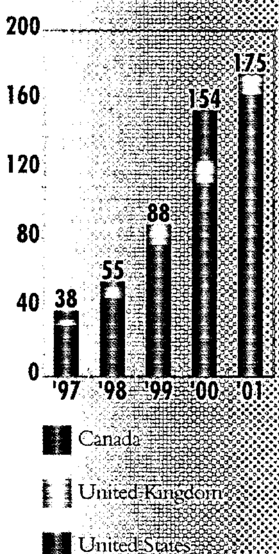
(Thousands of dollars)	2001	2000	1999
Income contribution before special items	**$ 89,036**	54,456	14,881
Total assets	**918,764**	1,018,555	838,295
Capital expenditures	**175,186**	153,750	88,075
Crude oil processed – barrels a day	**167,199**	165,820	143,204
Products sold – barrels a day	**205,318**	179,515	159,042
Average gross margin on products sold – dollars a barrel			
United States	**$ 3.23**	1.91	.66
United Kingdom	**3.29**	4.69	3.38



Upon completion of the hydrocracker unit in 2003, Murphy will produce a full slate of low-sulfur products at the Meraux refinery to support their growing retail marketing program.

Capital Expenditures – Refining and Marketing

(millions of dollars)



In conjunction with the expansion of our Wal-Mart program, we are also expanding our refinery in Meraux, Louisiana from 100,000 to 125,000 barrels per day of crude oil throughput capacity. The expansion will help us to supply our Murphy USA stations and includes the addition of a hydrocracker unit that will allow us to meet the new low-sulfur gasoline and diesel standards. In fact, by starting hydrocracker construction early, Meraux will be one of the first refineries in the country to offer a "green" product slate to its customers, which may create additional marketing opportunities.

Our successful niche refinery at Superior, Wisconsin, provides consistently healthy asphalt margins with minimum capital requirements. We will continue to capitalize on strong demand for asphalt and light products and take advantage of any weakness in heavy crude oil prices.

During 2001, we sold our Canadian pipeline and trucking operation for $163 million. This sale reflects our continuing efforts to rationalize non-core assets and demonstrates our commitment to increasing shareholder value, as we concentrate on the Wal-Mart side of our downstream business in North America.

In the United Kingdom, we continue to actively look for underperforming, yet potentially attractive, stores to purchase and convert to our well-received Costcutter neighborhood market format.

Murphy is distinctly different from other energy companies. We have built, from our foundation of low-cost, long-lived producing properties, a focused strategy for growth with a stellar range of opportunities. The success achieved to date will provide us steady, future production growth combined with significant exploration potential yet to be tested in the deepwater Gulf of Mexico and Malaysia. The pieces are in place and we are experiencing initial success. However, we do not expect success to end here. Given the exploration portfolio, the fields in development, and continued Wal-Mart expansion, I believe the best is yet to come.

> ***Murphy is distinctly different from other energy companies. We have built, from our foundation of low-cost, long-lived producing properties, a focused strategy for growth with a stellar range of opportunities.***

We feel strongly that over the last several years we have put together outstanding investment programs that will continue to deliver above-market returns. By concentrating on the highest quality assets in the industry, we have built a company that will not only grow but prosper.

I thank you for your continued support.

Claiborne P. Deming

Claiborne P. Deming
President and Chief Executive Officer

February 1, 2002
El Dorado, Arkansas

STATISTICAL SUMMARY

	2001	2000	1999	1998	1997
Exploration and Production					
Net crude oil and condensate production – barrels a day					
United States	**5,303**	6,035	7,582	7,025	9,565
Canada – light	**2,937**	2,606	2,992	3,219	3,351
heavy	**11,707**	10,574	9,099	9,676	11,538
offshore	**9,535**	9,199	6,404	4,192	224
synthetic	**10,479**	8,443	10,997	10,500	9,341
United Kingdom	**20,049**	20,679	20,217	14,975	13,438
Ecuador	**5,319**	6,405	7,104	7,720	7,802
Net natural gas liquids production – barrels a day					
United States	**460**	628	879	773	1,195
Canada	**1,401**	474	488	612	617
United Kingdom	**165**	216	321	436	423
Total liquids produced	**67,355**	65,259	66,083	59,128	57,494
Net crude oil and condensate sold – barrels a day					
United States	**5,303**	6,034	7,588	7,018	9,557
Canada – light	**2,937**	2,606	2,992	3,219	3,351
heavy	**11,707**	10,574	9,099	9,676	11,538
offshore	**9,862**	9,456	4,727	4,396	147
synthetic	**10,479**	8,443	10,997	10,500	9,341
United Kingdom	**20,206**	20,921	20,217	15,336	12,597
Ecuador	**5,381**	6,393	7,104	7,907	7,614
Net natural gas liquids sold – barrels a day					
United States	**460**	628	879	773	1,195
Canada	**1,401**	474	488	612	617
United Kingdom	**148**	216	321	436	423
Total liquids sold	**67,884**	65,745	64,412	59,873	56,380
Net natural gas sold – thousands of cubic feet a day					
United States	**115,527**	144,789	171,762	169,519	211,207
Canada	**152,583**	73,773	56,238	48,998	44,853
United Kingdom	**13,125**	10,850	12,443	12,384	12,609
Total natural gas sold	**281,235**	229,412	240,443	230,901	268,669
Net hydrocarbons produced – equivalent barrels[1,2] a day	**114,228**	103,494	106,157	97,612	102,272
Estimated net hydrocarbon reserves – million equivalent barrels[1,2,3]	**501.2**	442.3	400.8	379.9	362.1
Weighted average sales prices[4]					
Crude oil and condensate – dollars a barrel					
United States	**$ 24.92**	30.38	18.09	12.89	19.51
Canada[5] – light	**22.40**	27.68	17.00	12.03	17.74
heavy	**11.06**	17.83	12.77	6.56	10.76
offshore	**23.77**	27.16	19.08	11.80	16.35
synthetic	**25.04**	29.62	18.64	13.73	19.92
United Kingdom	**24.44**	27.78	18.09	12.52	18.89
Ecuador	**17.00**	22.01	14.42	8.56	13.48
Natural gas liquids – dollars a barrel					
United States	**20.40**	23.04	13.70	11.50	15.82
Canada[5]	**20.35**	19.98	12.09	9.16	14.87
United Kingdom	**19.12**	23.64	13.45	11.04	18.02
Natural gas – dollars a thousand cubic feet					
United States	**4.64**	4.01	2.34	2.25	2.64
Canada[5]	**3.28**	3.67	1.96	1.40	1.42
United Kingdom[5]	**2.52**	1.81	1.68	2.23	2.65

[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

	2001	2000	1999	1998	1997
Refining					
Crude capacity* of refineries – barrels per stream day	**167,400**	167,400	167,400	167,400	167,400
Refinery inputs – barrels a day					
Crude – Meraux, Louisiana	**104,345**	103,154	82,410	101,834	101,150
– Superior, Wisconsin	**35,869**	34,159	33,402	32,966	33,704
– Milford Haven, Wales	**26,985**	28,507	27,392	30,780	26,706
Other feedstocks	**9,901**	8,298	10,484	11,404	8,178
Total inputs	**177,100**	174,118	153,688	176,984	169,738
Refinery yields – barrels a day					
Gasoline	**73,217**	75,106	65,216	73,482	72,672
Kerosine	**12,874**	11,955	11,316	15,394	14,959
Diesel and home heating oils	**52,660**	49,606	44,054	50,506	44,681
Residuals	**20,530**	18,524	17,370	21,310	20,852
Asphalt, LPG and other	**13,467**	14,624	12,225	12,565	13,139
Fuel and loss	**4,352**	4,303	3,507	3,727	3,435
Total yields	**177,100**	174,118	153,688	176,984	169,738
Average cost of crude inputs to refineries – dollars a barrel					
United States	$ **23.44**	28.82	18.80	12.55	18.54
United Kingdom	**24.86**	29.29	17.22	13.62	20.12
Marketing					
Products sold – barrels a day					
United States – Gasoline	**96,597**	76,171	61,190	60,990	62,244
– Kerosine	**9,621**	8,517	7,545	10,170	9,301
– Diesel and home heating oils	**41,064**	39,347	34,514	40,403	36,192
– Residuals	**17,308**	15,163	13,812	16,170	16,527
– Asphalt, LPG and other	**9,666**	10,271	9,134	9,887	9,945
	174,256	149,469	126,195	137,620	134,209
United Kingdom – Gasoline	**11,058**	11,622	12,511	14,058	11,467
– Kerosine	**2,547**	2,478	3,053	4,369	3,795
– Diesel and home heating oils	**11,798**	9,760	10,995	10,884	7,638
– Residuals	**3,538**	3,852	3,608	5,203	4,215
– LPG and other	**2,121**	2,191	2,084	1,579	1,862
	31,062	29,903	32,251	36,093	28,977
Canada	**–**	143	596	439	244
Total products sold	**205,318**	179,515	159,042	174,152	163,430
Average gross margin on products sold – dollars a barrel					
United States	$ **3.23**	1.91	.66	1.45	1.76
United Kingdom	**3.29**	4.69	3.38	2.81	2.90
Branded retail outlets*					
United States	**815**	712	625	552	585
United Kingdom	**411**	386	384	389	396
Stockholder and Employee Data					
Common shares outstanding* (thousands)	**45,331**	45,046	44,998	44,950	44,891
Number of stockholders of record*	**2,991**	3,185	3,431	3,684	3,899
Number of employees*	**3,779**	3,109	2,153	1,566	1,446
Average number of employees	**3,438**	2,528	1,797	1,498	1,421
Salaries, wages and benefits (thousands)	$ **148,561**	120,906	103,757	97,307	92,495

*At December 31.

DIRECTORS

R. Madison Murphy [1]
Chairman of the Board
Murphy Oil Corporation
El Dorado, Arkansas
Director since 1993

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

B. R. R. Butler [3,4]
Managing Director, Retired
The British Petroleum Company p.l.c.
Holbeton, Devon, England
Director since 1991

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 [3,4]
Chairman of the Board
Purvin & Gertz, Inc.
Houston, Texas
Director since 1999

Michael W. Murphy [3]
President
Marmik Oil Company
El Dorado, Arkansas
Director since 1977

William C. Nolan Jr. [1,2,3]
Partner
Nolan and Alderson
El Dorado, Arkansas
Director since 1977

William L. Rosoff [3]
Senior Vice President and General Counsel
Marsh & McLennan Companies, Inc.
New York, New York
Director since 2001

David J. H. Smith [3,4]
Chief Executive Officer, Retired
Whatman plc
Maidstone, Kent, England
Director since 2001

Caroline G. Theus [1,3,4]
President
Keller Enterprises, LLC
Alexandria, Louisiana
Director since 1985

OFFICERS

R. Madison Murphy
Chairman of the Board

Claiborne P. Deming
President and Chief Executive Officer

Herbert A. Fox Jr.
Executive Vice President—Worldwide Downstream Operations

Steven A. Cosse
Senior Vice President and General Counsel

Bill H. Stobaugh
Vice President

Kevin G. Fitzgerald
Treasurer

John W. Eckart
Controller

Walter K. Compton
Secretary

DIRECTORS EMERITI

C. H. Murphy Jr.

William C. Nolan

George S. Ishiyama

Committees of the Board

1 Member of the Executive Committee chaired by Mr. R. Madison Murphy.

2 Member of the Audit Committee chaired by Mr. Dembroski.

3 Member of the Executive Compensation and Nominating Committee chaired by Mr. William C. Nolan Jr.

4 Member of the Public Policy and Environmental Committee chaired by Mr. Butler.

PRINCIPAL SUBSIDIARIES

Murphy Exploration & Production Company

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

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

Engaged worldwide in crude oil and natural gas exploration and production

Enoch L. Dawkins
President

John C. Higgins
Senior Vice President, U.S. Exploration and Production

David M. Wood
Senior Vice President, Frontier Exploration and Production

S. J. Carboni Jr.
Vice President, Deepwater Development and Production

James R. Murphy
Vice President, U.S. Exploration

Steven A. Cossé
Vice President and General Counsel

Kevin G. Fitzgerald
Treasurer

Bobby R. Campbell
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, Supply and Engineering

Gary R. Bates
Vice President, Supply and Transportation

Henry J. Heithaus
Vice President, Retail Marketing

Kevin W. Melnyk
Vice President, Manufacturing

Steven A. Cossé
Vice President and General Counsel

Gordon W. Williamson
Treasurer

John W. Eckart
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, and extraction and sale of synthetic crude oil 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 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

Ernest C. Cagle
Vice President, Supply

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, 2001**

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, 2002, as quoted by the New York Stock Exchange, was approximately $2,721,379,000.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2002 was 45,359,683.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 8, 2002 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 the United States 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 the United States 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 2001 Annual Report to Security Holders (2001 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 7 through 15, F-11, F-25 through F-27, and F-30 through F-32 of this Form 10-K report and on pages 1 through 8 of the 2001 Annual Report.

Exploration and Production

During 2001, 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 2001 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 into synthetic crude oil. Subsidiaries of Murphy Expro conducted exploration activities in various other areas including Ireland and Spain.

Murphy's estimated net quantities of proved oil and gas reserves and proved developed oil and gas reserves at December 31, 1998, 1999, 2000 and 2001 by geographic area are reported on page F-29 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, 2001 are shown on page 9 of the 2001 Annual Report.

Production expenses for the last three years in U.S. dollars per equivalent barrel are discussed on page 11 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-28 through F-33 of this Form 10-K report.

At December 31, 2001, Murphy held leases, concessions, contracts or permits on nonproducing and producing 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.

	Nonproducing		Producing		Total	
Area (Thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States – Onshore	7	5	38	20	45	25
– Gulf of Mexico	878	544	300	100	1,178	644
– Frontier	59	16	5	1	64	17
Total United States	944	565	343	121	1,287	686
Canada – Onshore	1,297	890	1,040	336	2,337	1,226
– Offshore	12,803	2,221	54	2	12,857	2,223
– Oil sands	240	72	96	5	336	77
Total Canada	14,340	3,183	1,190	343	15,530	3,526
United Kingdom	940	266	83	12	1,023	278
Ecuador	–	–	494	99	494	99
Malaysia	8,659	7,057	–	–	8,659	7,057
Ireland	709	177	–	–	709	177
Spain	330	99	–	–	330	99
Totals	25,922	11,347	2,110	575	28,032	11,922

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, 2001.

	Oil Wells		Gas Wells	
Country	**Gross**	**Net**	**Gross**	**Net**
United States	273	114.7	181	72.3
Canada	2,839	682.8	884	402.5
United Kingdom	109	13.1	21	1.5
Ecuador	66	13.2	–	–
Totals	3,287	823.8	1,086	476.3
Wells included above with multiple completions and counted as one well each	72	31.7	75	58.4

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

	United States		Canada		United Kingdom		Ecuador		Other		Total	
	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry
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
1999												
Exploratory	1.4	1.0	5.3	5.5	–	–	.4	–	–	–	7.1	6.5
Development	.6	–	13.7	.2	1.0	–	.8	–	–	–	16.1	.2

Murphy's drilling wells in progress at December 31, 2001 are shown below.

	Exploratory		Development		Total	
Country	Gross	Net	Gross	Net	Gross	Net
United States	–	–	2	.6	2	.6
Canada	7	3.2	3	.3	10	3.5
United Kingdom	–	–	2	.1	2	.1
Totals	7	3.2	7	1.0	14	4.2

Additional information about current exploration and production activities is reported on pages 1 through 8 of the 2001 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, 2001 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
Pretreating cat-reforming feeds	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	3,104,000	2,638,000	10,042,000

*Barrels per stream day.

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, 2001, the Company marketed products through 387 Murphy USA stations and 428 SPUR stations. MOUSA plans to add about 110 new Murphy USA stations at Wal-Mart sites in the southern and midwestern United States in 2002.

At the end of 2001, Murco distributed refined products in the United Kingdom from the Milford Haven refinery, three wholly owned terminals supplied by rail, five terminals owned by others where products are received in exchange for deliveries from the Company's terminals, and 411 branded stations under the brand names MURCO and EP.

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 plans to construct about five to seven stations at Wal-Mart sites in Canada in 2002. Further stations are expected to be added gradually after 2002.

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, 2001 are reported on pages 1, 7, 8 and 10 of the 2001 Annual Report.

Employees

At December 31, 2001, Murphy had 3,779 employees – 1,863 full-time and 1,916 part-time.

Competition and Other Conditions Which May Affect Business

Murphy operates in the oil industry and experiences intense competition from other oil and gas companies, many of which have substantially greater resources. 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 Wal-Mart stores. 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 18 of this Form 10-K report.

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 15 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. 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, 2002, 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.

R. Madison Murphy – Age 44; Chairman of the Board since October 1994 and Director and Member of the Executive Committee since 1993. Mr. Murphy served as Executive Vice President and Chief Financial and Administrative Officer from 1993 to 1994; Executive Vice President and Chief Financial Officer from 1992 to 1993; Vice President, Planning/Treasury, from 1991 to 1992; and Vice President, Planning, from 1988 to 1991, with additional duties as Treasurer from 1990 until August 1991.

Claiborne P. Deming – Age 47; 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.

Herbert A. Fox Jr. – Age 67; Executive Vice President – Worldwide Downstream Operations since November 2001. Mr. Fox was elected Vice President in 1994 and served as President of MOUSA between 1992 and October 2001. He served as Vice President, Manufacturing, for MOUSA from 1990 to 1992.

Steven A. Cossé – Age 54; 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 50; 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 46; 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 43; 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 39; 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 June 2000, the U.S. Government filed a lawsuit against Murphy Oil USA, Inc., the Company's wholly-owned subsidiary, in federal court in Madison, Wisconsin, alleging violations of environmental laws at the Company's Superior, Wisconsin refinery. The lawsuit was divided into liability and damage phases, and on August 1, 2001, the court ruled against the Company in the liability phase of the trial. Subsequent to the court ruling, the Company and the U.S. Government reached a tentative settlement agreement that was filed with the federal court in January 2002. The settlement is subject to approval by the court following a 30-day public comment period that expires March 7, 2002. According to the tentative settlement agreement, the Company is to pay a civil penalty of $5.5 million and implement other environmental projects to resolve Clean Air Act violations. The Company has recorded a liability of $5.5 million to cover the penalty. Although the settlement is tentative and no assurance can be given, the Company does not believe that the ultimate resolution of this matter will have a material adverse effect on its financial condition.

In December 2000, two of the Company's Canadian subsidiaries 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 acquired the lands after first inappropriately obtaining confidential and proprietary data belonging to the Company and its joint venturer. In January 2001, one of the defendants, 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 joint venturer at cost. In February 2001, the remaining defendants, representing the remaining undivided 25% of the lands in question, filed a counterclaim against the Company's two Canadian subsidiaries and one officer individually seeking compensatory damages of C$6.14 billion. The Company believes the counterclaim is without merit and the amount of damages sought is frivolous and 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 2001.

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 2,991 stockholders of record as of December 31, 2001. Information as to high and low market prices per share and dividends per share by quarter for 2001 and 2000 are reported on page F-34 of this Form 10-K report.

Item 6. SELECTED FINANCIAL DATA

(Thousands of dollars except per share data)	2001	2000	1999	1998	1997
Results of Operations for the Year*					
Sales and other operating revenues	$ 4,466,821	4,614,341	2,752,083	2,342,644	3,301,542
Net cash provided by operating activities	635,704	747,751	341,711	297,467	365,825
Income (loss) before cumulative effect of accounting change	330,903	305,561	119,707	(14,394)	132,406
Net income (loss)	330,903	296,828	119,707	(14,394)	132,406
Per Common share – diluted					
Income (loss) before cumulative effect of accounting change	7.26	6.75	2.66	(.32)	2.94
Net income (loss)	7.26	6.56	2.66	(.32)	2.94
Cash dividends per Common share	1.50	1.45	1.40	1.40	1.35
Percentage return on					
Average stockholders' equity	23.5	26.4	12.3	(1.3)	12.7
Average borrowed and invested capital	17.7	20.3	9.7	(.6)	10.4
Average total assets	10.2	11.2	5.2	(.6)	6.0
Capital Expenditures for the Year					
Exploration and production	$ 683,448	392,732	295,958	331,647	423,181
Refining and marketing	175,186	153,750	88,075	55,025	37,483
Corporate and other	5,806	11,415	2,572	2,127	7,367
	$ 864,440	557,897	386,605	388,799	468,031
Financial Condition at December 31					
Current ratio	1.07	1.10	1.22	1.15	1.10
Working capital	$ 38,604	71,710	105,477	56,616	48,333
Net property, plant and equipment	2,525,807	2,184,719	1,782,741	1,662,362	1,655,838
Total assets	3,259,099	3,134,353	2,445,508	2,164,419	2,238,319
Long-term debt	520,785	524,759	393,164	333,473	205,853
Stockholders' equity	1,498,163	1,259,560	1,057,172	978,233	1,079,351
Per share	33.05	27.96	23.49	21.76	24.04
Long-term debt – percent of capital employed	25.8	29.4	27.1	25.4	16.0

*Includes effects on income of special items in 2001, 2000 and 1999 that are detailed in Management's Discussion and Analysis of Financial Condition and Results of Operations. Also, special items in 1998 and 1997 increased (decreased) net income by $(57,935), $(1.29) per diluted share, and $68, with no per share effect, respectively.

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

Results of Operations

The Company reported record net income in 2001 of $330.9 million, $7.26 a diluted share, compared to net income in 2000 of $296.8 million, $6.56 a diluted share. In 1999, the Company earned $119.7 million, $2.66 a diluted share. Net income for the three years ended December 31, 2001 included certain special items that resulted in a net benefit of $67.6 million, $1.48 a diluted share, in 2001; a net charge of $7.2 million, $.16 a diluted share, in 2000; and a net benefit of $19.7 million, $.44 a diluted share, in 1999. The special items in 2001 included an after-tax benefit of $71 million, $1.56 a diluted share, from the sale of Canadian pipeline and trucking assets; and a benefit of $8.9 million, $.19 a diluted share, from settlement of income tax matters and a reduction of a provincial tax rate in Canada. Other special items that decreased earnings in 2001 included an after-tax charge of $6.8 million, $.15 a diluted share, for asset impairments under Statement of Financial Accounting Standards (SFAS) No. 121; and a charge of $5.5 million, $.12 a diluted share, relating to resolution of Clean Air Act violations at the Company's Superior, Wisconsin refinery. The special items in 2000 included a benefit from settlement of income tax matters for $25.6 million, $.56 a share, and a gain on sale of assets of $1.5 million, $.03 a share. Unusual items that decreased earnings in 2000 included an after-tax charge of $17.8 million, $.39 a diluted share, from asset impairments; a charge of $7.8 million, $.17 a share, for transportation and other disputed contractual items under the Company's concessions in Ecuador; and an after-tax charge of $8.7 million, $.19 a share, for a change in accounting for the Company's unsold crude oil production. The 1999 special items included after-tax gains of $7.5 million, $.17 a diluted share, from sale of assets; and $12.2 million, $.27 a diluted share, primarily from settlements of income taxes and other matters.

2001 vs. 2000 – Excluding special items, income in 2001 totaled $263.3 million, $5.78 a diluted share, which was $40.7 million lower than the $304 million, $6.72 a diluted share, earned in 2000. The decline primarily arose from a decrease of $90.2 million in earnings from exploration and production operations caused by an 18% reduction in realized oil prices during 2001 and higher exploration expenses. The Company's North American natural gas sales price declined 1% during 2001 to a realized price of $3.87 per MCF. Production of oil and natural gas were at record levels during 2001, increasing by 3% and 23%, respectively, compared to 2000. Refining and marketing operations produced record earnings during 2001 as income before special items increased by 63% to $89 million. Stronger unit margins in the U.S. during the first half of the year caused the improved results. The costs of corporate activities, which include interest income and expense and corporate overhead not allocated to operating functions, were $13.8 million in 2001, excluding special items, compared to $28.8 million in 2000. The $15 million reduction in 2001 was primarily due to higher income tax benefits in the current year.

2000 vs. 1999 – Income before special items in 2000 was a Company record $304 million, $6.72 a diluted share. The results for 2000 represented a $204 million improvement compared to income before special items of $100 million, $2.22 a diluted share, in 1999. The improvement primarily arose from record earnings from the Company's exploration and production operations, which amounted to $278.3 million in 2000 compared to $121.2 million in 1999. Higher sales prices for both crude oil and natural gas were the principal reasons behind the higher exploration and production earnings. The Company's average worldwide sales price for crude oil and condensate was $25.96 per barrel in 2000 and $17.08 per barrel in 1999. The average sales price of North American natural gas improved from $2.25 per thousand cubic feet (MCF) in 1999 to $3.90 in 2000. Earnings from refining and marketing operations increased from $14.9 million in 1999 to $54.5 million in 2000. These results improved due to better unit margins in both the United States and the United Kingdom. The costs of corporate activities were $28.8 million in 2000, excluding special items, compared to $36.1 million in 1999. The reduction in 2000 was primarily due to lower net interest costs and lower compensation expense for awards under the Company's stock-based incentive plans.

In the following table, the Company's results of operations for the three years ended December 31, 2001 are presented by segment. Special items, which can obscure underlying trends of operating results and affect comparability between years, are set out separately. More detailed reviews of operating results for the Company's exploration and production and refining and marketing activities follow the table.

(Millions of dollars)	2001	2000	1999
Exploration and production			
United States	$ 63.6	63.9	30.3
Canada	79.7	112.3	47.0
United Kingdom	76.7	90.2	37.2
Ecuador	11.5	28.9	14.4
Malaysia	(36.1)	(10.7)	(1.7)
Other	(7.3)	(6.3)	(6.0)
	188.1	278.3	121.2
Refining and marketing			
United States	71.1	23.9	(5.9)
United Kingdom	14.1	23.0	14.0
Canada	3.8	7.6	6.8
	89.0	54.5	14.9
Corporate and other	(13.8)	(28.8)	(36.1)
Income before special items and cumulative effect of accounting change	263.3	304.0	100.0
Gain on sale of assets	71.0	1.5	7.5
Income tax settlements and tax rate change	8.9	25.6	5.0
Impairment of properties	(6.8)	(17.8)	–
Provision for environmental matter	(5.5)	–	–
Gain (loss) on transportation and other disputed contractual items in Ecuador	–	(7.8)	8.2
Provision for reduction in force	–	–	(1.0)
Income before cumulative effect of accounting change	330.9	305.5	119.7
Cumulative effect of accounting change	–	(8.7)	–
Net income	$ 330.9	296.8	119.7

Exploration and Production – Earnings from exploration and production operations before special items were $188.1 million in 2001, compared to earnings of $278.3 million in 2000 and $121.2 million in 1999. 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 increased from 65,259 barrels per day in 2000 to 67,355 in 2001, a 3% increase. Natural gas sales volumes totaled 281.2 million cubic feet per day in 2001, up 23% from 229.4 million in 2000. The improvement in 2000 earnings compared to 1999 was primarily due to increases in the Company's crude oil sales prices and higher sales prices for its North American natural gas production. Production of crude oil, condensate and natural gas liquids decreased 1% in 2000, and natural gas sales volumes fell 5% as declines in the U.S. Gulf of Mexico more than offset higher oil and gas sales volumes in Canada. Higher exploration expenses in 2000 compared to 1999 partially offset the effects of higher commodity prices.

The results of operations for oil and gas producing activities for each of the last three years are shown by major operating area on pages F-31 and F-32 of this Form 10-K report. Daily production and sales rates and weighted average sales prices are shown on page 9 of the 2001 Annual Report.

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

(Millions of dollars)	**2001**	**2000**	**1999**
United States			
Crude oil	$ 51.9	72.4	54.4
Natural gas	192.8	211.4	147.6
Canada			
Crude oil	167.2	193.9	107.7
Natural gas	182.6	99.0	40.2
Synthetic oil	95.8	91.5	74.8
United Kingdom			
Crude oil	181.5	214.6	134.7
Natural gas	12.1	7.8	7.7
Ecuador – crude oil	33.4	52.2	36.1
Total oil and gas revenues	$ 917.3	942.8	603.2

The Company's crude oil, condensate and natural gas liquids production averaged 67,355 barrels per day in 2001, 65,259 in 2000 and 66,083 in 1999. Sales volumes in 2001 were slightly higher and averaged 67,884 barrels per day. Oil production in the United States declined 14% in 2001, following a 21% decline in 2000. The reduction in both years was primarily due to declines from existing fields in the Gulf of Mexico. Oil production in Canada increased 15% in 2001 to a record volume of 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 a combination of higher gross production and a lower net profit royalty caused by increased capital spending and a lower oil price. Before royalties, the Company's synthetic oil production was 11,157 barrels per day in 2001, 10,145 in 2000 and 11,146 in 1999. 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 Exploration Ltd. (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. In 2000, oil production increased 4% in Canada. Production at Hibernia rose 2,795 barrels per day due to improved operations. Heavy oil production in western Canada was 1,475 barrels per day higher in 2000 due primarily to an active drilling program in the early part of the year. The Company's share of net production at its synthetic oil operation in Canada was down 2,554 barrels per day in 2000 due to a combination of more downtime for maintenance and a higher net profit royalty caused by higher prices. Production of light oil in Canada decreased 400 barrels per day in 2000. U.K. production increased 357 barrels per day in 2000 as improved volumes at Mungo/Monan and Schiehallion were almost offset by declines at more mature fields in the North Sea. Production in Ecuador was down 699 barrels per day in 2000 due to pipeline constraints.

Worldwide sales of natural gas were a record 281.2 million cubic feet per day in 2001, up from 229.4 million in 2000. Natural gas sales were 240.4 million cubic feet per day in 1999. Sales of natural gas in the United States were 115.5 million cubic feet per day in 2001, 144.8 million in 2000 and 171.8 million in 1999. The reductions in 2001 and 2000 were due to lower deliverability from maturing fields in the Gulf of Mexico. Natural gas sales in Canada in 2001 were at record levels for the sixth consecutive year as sales increased 107% to 152.6 million cubic feet per day. Canadian natural gas sales had increased 31% in 2000. The increase in 2001 was primarily due to the acquisition of Beau Canada; production in both 2001 and 2000 benefited from new discoveries in western Canada. Natural gas sales in the United Kingdom were 13.1 million cubic feet per day in 2001, up 21% compared to 2000. U.K. natural gas sales in 2000 decreased 1.6 million cubic feet per day from 1999 levels.

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

Worldwide crude oil sales prices in 2000 were significantly higher than in 1999. In the United States, Murphy's 2000 average sales prices for crude oil and condensate averaged $30.38 per barrel for the year, 68% above 1999. In Canada, the average sales price for light oil was $27.68 per barrel in 2000, an increase of 63%. Heavy oil prices averaged $17.83 per barrel, up 40% compared to 1999. The average sales price for synthetic oil in 2000 was $29.62 per barrel, up 59%. The sales price for crude oil from the Hibernia field increased 42% to $27.16 per barrel. U.K. sales prices averaged 54% higher in 2000 at $27.78 per barrel. Sales prices in Ecuador were $22.01 per barrel in 2000, up 53% from a year earlier.

The Company's 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 average 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.

North American natural gas sales prices strengthened during 2000 due to supply being short of demand. A combination of a hotter than normal summer and a colder than normal early winter near the end of 2000 in the United States strained an already below-normal level of gas storage throughout the country. Natural gas sales prices in the United States increased 71% from 1999 and averaged $4.01 per MCF in 2000 compared to $2.34 in the prior year. The average price for natural gas sold in Canada during 2000 increased 87% to $3.67 per MCF, while prices in the United Kingdom increased 8% to $1.81.

Based on 2001 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 $16.2 million and $6.4 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 $218 million in 2001, $181.9 million in 2000 and $162.1 million in 1999. These amounts are shown by major operating area on pages F-31 and F-32 of this Form 10-K report. Cost per equivalent barrel during the last three years were as follows.

(Dollars per equivalent barrel)	2001	2000	1999
United States	$ 5.30	3.72	2.98
Canada			
Excluding synthetic oil	3.84	4.24	3.99
Synthetic oil	13.58	13.06	9.09
United Kingdom	3.75	3.46	3.73
Ecuador	7.60	6.65	5.10
Worldwide – excluding synthetic oil	4.36	4.05	3.62

The increase in the cost per equivalent barrel in the United States in both 2001 and 2000 was attributable to a combination of lower production and higher well servicing costs. The decrease in Canada during 2001, excluding synthetic oil, was primarily due to increased production in all categories. The increase in the cost per equivalent barrel for Canadian synthetic oil in 2001 was due to higher maintenance costs. The increase in unit cost in the United Kingdom during 2001 was the result of higher costs to maintain mature properties, including Ninian, and the increase in Ecuador in 2001 was due to lower production during the year. The 2000 increase in Canada, excluding synthetic oil, was due to an increase in well servicing costs at heavy oil properties offset in part by the effect of higher production at Hibernia, where production expenses are lower than in western Canada. The increase for Canadian synthetic oil in 2000 was due to lower net production caused by a combination of less gross production volumes and an increase in royalty barrels caused by higher oil prices. Based on the Company's interest in Syncrude's gross production, cost per barrel increased 21% in 2000. A lower unit cost in the United Kingdom in 2000 was due to a favorable impact from higher production at the Mungo/Monan and Schiehallion fields. Higher cost per barrel in Ecuador in 2000 was attributable to both lower production and higher overall operating expenses.

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-31 and F-32 of this Form 10-K report. Certain of the expenses are included in the capital expenditure totals for exploration and production activities.

(Millions of dollars)	**2001**	**2000**	**1999**
Exploratory expenditures charged against income			
Dry hole costs	$ 82.8	66.0	32.4
Geological and geophysical costs	36.0	36.3	18.7
Other costs	15.0	9.2	8.5
	133.8	111.5	59.6
Undeveloped lease amortization	23.1	14.1	11.0
Total exploration expenses	$ 156.9	125.6	70.6

Depreciation, depletion and amortization related to exploration and production operations totaled $183.7 million in 2001, $169.2 million in 2000 and $166.9 million in 1999. The increase in 2001 was due to record levels of oil and natural gas sales during the year. The increase in 2000 was due to higher production from Hibernia field, offshore eastern Canada, and higher depreciation rates per unit on production from properties acquired from Beau Canada in November 2000.

Refining and Marketing – Earnings before special items from refining and marketing operations were a record $89 million in 2001. Comparable earnings in 2000 and 1999 were $54.5 million and $14.9 million, respectively. Operations in the United States earned $71.1 million in 2001 compared to $23.9 million in 2000, due to stronger refining margins and a higher percentage of sales through the Company's retail stations at Wal-Mart stores. U.S. operations lost $5.9 million in 1999. The increase in 2000 was due to product sales realizations increasing more than the cost of crude oil and other refinery feedstocks. Operations in the United Kingdom earned $14.1 million in 2001, $23 million in 2000 and $14 million in 1999. The decline in 2001 earnings was caused by generally weaker U.K. refining margins compared to 2000. Strong refining margins in the United Kingdom in 2000 led to record earnings for this operation. The Company earned $3.8 million in 2001 from its crude oil trading and transportation business in Canada prior to the sale of these pipeline and trucking assets in May 2001. The Canadian operations earned $7.6 million and $6.8 million in 2000 and 1999, respectively.

Unit margins (sales realizations less costs of crude oil, other feedstocks, refining and transportation to point of sale) averaged $3.23 per barrel in the United States in 2001, $1.91 in 2000 and $.66 in 1999. U.S. product sales increased 17% to a record 174,256 barrels per day in 2001, following an 18% increase in 2000. Higher product sales volumes in 2001 and 2000 were 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 $3.29 per barrel in 2001, $4.69 in 2000 and $3.38 in 1999. Sales of petroleum products were up 4% in 2001 due to higher volumes sold in the cargo market. Sales volumes in 2000 were down 7% compared to 1999, with the decline attributable to lower consumer demand in the United Kingdom caused by the large increase in product prices during the year.

Both U.S. and U.K. unit margins have been significantly weaker in early 2002, and both operations were experiencing losses during the early part of the year.

Based on sales volumes for 2001 and deducting taxes at marginal rates, each $.42 per barrel ($.01 per gallon) fluctuation in unit margins would have affected annual refining and marketing profits by $19.9 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.

Special Items – Net income for the last three years included certain special items reviewed in the following paragraphs. The effects of special items on quarterly results for 2001 and 2000 are presented on page F-34 of this Form 10-K report.

- *Gain on 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, and $6.3 million and $1.2 million were recorded in the third and fourth quarters, respectively, of 1999 from the sale of U.S. service stations.

- *Income tax settlements and tax rate change* – 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, $10.1 million and $5 million from settlement of U.S. income tax matters was recorded in the third quarter of 2000, the fourth quarter of 2000 and the fourth quarter of 1999, respectively.

- *Impairment of properties* – After-tax provisions of $6.8 million, $13.6 million and $4.2 million were recorded in 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 D to the consolidated financial statements.)

- *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.

- *Gain (loss) on transportation and other disputed contractual items in Ecuador* – A loss of $7.8 million was recorded in the fourth quarter of 2000 and a gain of $8.2 million was recorded in the fourth quarter of 1999 related to transportation and other contractual disputes under the Company's concessions in Ecuador.

- *Provision for reduction in force* – An after-tax charge of $1 million for a reduction in force program was recorded in the first quarter of 1999. (See Note G to the consolidated financial statements.)

- *Cumulative effect of accounting change* – An after-tax charge of $8.7 million was recorded in the first quarter of 2000 to account for the Company's unsold crude oil production at cost rather than at market value as in the past. (See Note B to the consolidated financial statements.)

The income (loss) effects of special items for each of the three years ended December 31, 2001 are summarized by segment in the following table.

(Millions of dollars)	**2001**	**2000**	**1999**
Exploration and production			
United States	$ (5.8)	(13.6)	5.0
Canada	5.8	(4.2)	–
United Kingdom	1.9	–	–
Ecuador	–	(7.8)	8.2
	1.9	(25.6)	13.2
Refining and marketing			
United States	(6.5)	–	7.5
Canada	71.1	–	–
	64.6	–	7.5
Corporate and other	1.1	27.1	(1.0)
Cumulative effect of accounting change	–	(8.7)	–
Total income (loss) from special items	$ 67.6	(7.2)	19.7

Capital Expenditures

As shown in the selected financial information on page 7 of this Form 10-K report, capital expenditures, including discretionary exploration expenditures, were $864.4 million in 2001 compared to $557.9 million in 2000 and $386.6 million in 1999. These amounts included $133.8 million, $111.5 million and $59.6 million of exploration costs that were expensed. Capital expenditures for exploration and production activities totaled $683.5 million in 2001, 79% of the Company's total capital expenditures for the year. Exploration and production capital expenditures in 2001 included $65.2 million for acquisition of undeveloped leases, $21.6 million for acquisition of proved oil and gas properties, $242.2 million for exploration activities, and $354.5 million for development projects. Development expenditures included $60.6 million for the Terra Nova oil field, offshore Newfoundland; $27.2 million for synthetic oil operations at Syncrude in Canada; and $96.3 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-30 of this Form 10-K report.

Refining and marketing expenditures, detailed in the following table, were 20% of total capital expenditures in 2001.

(Millions of dollars)	2001	2000	1999
Refining			
United States	$ 87.8	19.2	17.7
United Kingdom	1.1	4.3	7.0
Total refining	88.9	23.5	24.7
Marketing			
United States	75.0	92.8	58.7
United Kingdom	11.3	8.1	4.4
Total marketing	86.3	100.9	63.1
Other – Canada	–	29.4	.3
Total	$ 175.2	153.8	88.1

U.S. refining expenditures in 2001 included $55.1 million for clean fuels and crude throughput expansion projects at the Meraux refinery. U.S. refining expenditures in 2000 and 1999 and U.K. expenditures during the three years were primarily for capital projects to keep the refineries operating efficiently and within industry standards and to study alternatives for meeting anticipated future clean fuel specifications. Marketing expenditures in the United States primarily included the costs of new stations built at Wal-Mart stores. U.K. marketing expenditures in 2001 and 2000 were primarily for redevelopment of stores and station purchases; expenditures in 1999 were primarily for improvements and normal replacements at existing stations and terminals. Other capital expenditures in Canada in 2000 primarily consisted of the mid-year acquisition of the minority interest in the Manito pipeline system. The Manito pipeline and other Canadian pipeline and trucking assets were sold by the Company in May 2001.

Cash Flows

Cash provided by operating activities was $635.7 million in 2001, $747.8 million in 2000 and $341.7 million in 1999. Special items decreased cash flow from operations by $32.3 million in 2001 and $2.7 million in 2000, but increased cash by $18.9 million in 1999. Changes in operating working capital other than cash and cash equivalents provided cash of $66 million in 2000, but required cash of $28 million and $35.2 million in 2001 and 1999, respectively. Cash provided by operating activities was further reduced by expenditures for refinery turnarounds and abandonment of oil and gas properties totaling $16.4 million in 2001, $16.6 million in 2000 and $44.1 million in 1999.

Cash proceeds from property sales were $173 million in 2001, $20.7 million in 2000 and $40.9 million in 1999. Borrowings under notes payable and other long-term debt provided $88.2 million of cash in 2001, $175 million in 2000 and $247.8 million in 1999. Cash proceeds from stock option exercises and employee stock purchase plans amounted to $18.9 million in 2001, $3.8 million in 2000 and $2.3 million in 1999.

Property additions and dry hole costs required $813.5 million of cash in 2001, $512.3 million in 2000 and $359.4 million in 1999. Cash outlays for debt repayment during the three years included $77.7 million in 2001, $130.5 million in 2000 and $195.9 million in 1999. The acquisition of Beau Canada in November 2000 utilized $127.5 million of cash. Cash used for dividends to stockholders was $67.8 million in 2001, $65.3 million in 2000 and $63 million in 1999.

Financial Condition

Year-end working capital totaled $38.6 million in 2001, $71.7 million in 2000 and $105.5 million in 1999. 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 $51 million below current costs at December 31, 2001. Cash and cash equivalents at the end of 2001 totaled $82.7 million compared to $132.7 million a year ago and $34.1 million at the end of 1999.

Long-term debt was reduced by $4 million during 2001 to $520.8 million at the end of the year, 25.8% of total capital employed, and included $104.7 million of nonrecourse debt incurred in connection with the acquisition and development of the Hibernia oil field. The decrease in long-term debt in 2001 was attributable to repayments of nonrecourse debt, partially offset by other new borrowings. Long-term debt totaled $524.8 million at the end of 2000 compared to $393.2 million at December 31, 1999. Stockholders' equity was $1.5 billion at the end of 2001 compared to $1.3 billion a year ago and $1.1 billion at the end of 1999. A summary of transactions in stockholders' equity accounts is presented on page F-5 of this Form 10-K report.

Murphy had commitments of $506 million for capital projects in progress at December 31, 2001, including $206 million related to clean fuels and crude throughput expansion projects at the Meraux refinery and $94 million for costs to develop the Medusa field in the deepwater Gulf of Mexico.

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 2002 caused by significant capital expenditure commitments, as described in the preceding paragraph, and an expectation that oil and natural gas prices for much of 2002 will remain below trading ranges experienced in 2000 and early 2001. At December 31, 2001, the Company had access to short-term and long-term revolving credit facilities in the amount of $450 million, and also had unused available lines of credit with banks of $142.6 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 $1 billion in debt and equity securities. Current financing arrangements are set forth more fully in Note E to the consolidated financial statements. Based on the financing arrangements currently available, the Company does not expect to have any problems in meeting future requirements for funds.

At December 31, 2001, Murphy had $49 million of lease bonus and drilling costs in Property, Plant and Equipment associated with several leases in the eastern Gulf of Mexico. The U.S. government has thus far failed to issue the permits needed to develop and produce a large natural gas discovery on Company-held acreage in this area due to purported environmental concerns of the state of Florida. The Company and its co-venturers have sued the U.S. government over its failure to issue such permits, and the Company cannot predict whether the U.S. government will issue the permits needed to develop the discovery, or whether the Company will be compensated by the government in the event the permits are not issued.

Environmental

The Company's operations are 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 refineries, oil and gas fields, service stations, and terminals, for which known or potential obligations for environmental remediation exist.

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 three Superfund sites and has also been assigned responsibility by defendants at another Superfund site. The potential total cost to all parties to perform necessary remedial work at these sites may be substantial. Based on currently available information, the Company has reason to believe that it is a *de minimus* party as to ultimate responsibility at the four sites. The Company has not recorded a liability for remedial costs on Superfund sites. The Company could be required to bear a pro rata share of costs attributable to nonparticipating PRPs. Additionally, the Company could be assigned additional responsibility for remediation at these or other Superfund sites.

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.

The amount of future remediation costs incurred at known or currently unidentified sites could have a material adverse effect on future earnings. The Company does not expect that future costs for these matters will have a material adverse effect on its financial condition.

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, 2001.

The Company's refineries also incur costs to handle and dispose of hazardous waste and other chemical substances. These costs are expensed as incurred and amounted to $2.6 million in 2001. 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 $109 million in 2001 and are projected to be $166 million in 2002.

A lawsuit filed against Murphy by the U.S. Government is discussed under the caption "Legal Proceedings" on page 6 of this Form 10-K report.

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 2000 and early 2001, prices for oil field goods and services were adversely affected. Although oil and natural gas prices have weakened in the latter part of 2001 and into 2002, it is not possible to determine what effect these lower prices will have on the future cost of oil field goods and services.

Accounting changes and recent accounting pronouncements – As described in Note B on page F-9 of this Form 10-K report, Murphy adopted Statement of Financial Accounting Standard (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 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 immediately and will adopt SFAS No. 142 on January 1, 2002. The Company had unamortized goodwill of $50.4 million at December 31, 2001, which will be subject to the transition provisions of SFAS No. 142. Amortization expense related to goodwill was $3.1 million for the year ended December 31, 2001.

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.

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 will adopt the provisions of SFAS No. 144 effective January 1, 2002, and its provisions are generally to be applied prospectively.

At this time, it is not practicable to reasonably estimate the impact of adopting these accounting standards on the Company's financial statements, including whether any transitional goodwill impairment losses will be required to be recognized as the cumulative effect of a change in accounting principle.

Significant accounting policies – In preparing the financial statements of the Company 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 can not predict the types 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 operating results. 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 2001 were not significant.

- *Impairment of properties* – The Company continually monitors its long-lived assets recorded in Property, Plant and Equipment in the Consolidated Balance Sheet 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. 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 ultimate amount of recoverable oil and natural gas reserves 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 calendar year; (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 due to management's belief that certain of 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 when the Company should record losses for these 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 and capital commitments. Total payments due after 2001 under such contractual obligations are shown below.

	Amounts Due				
(Millions of dollars)	**Total**	**2002**	**2003-2005**	**2006-2007**	**After 2007**
Long-term debt	$ 569.0	48.2	165.2	81.7	273.9
Operating leases	236.8	17.6	49.7	31.6	137.9
Capital commitments	505.5	401.6	103.9	–	–
Total	$ 1,311.3	467.4	318.8	113.3	411.8

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**	**2002**	**2003-2005**	**2006-2007**	**After 2007**
Financial guarantees	$ 33.8	2.1	4.9	3.2	23.6
Letters of credit	35.6	6.8	13.3	2.2	13.3
Total	$ 69.4	8.9	18.2	5.4	36.9

Outlook

Prices for the Company's primary products are often quite volatile. During 2000 and early 2001, increased worldwide demand and disciplined management of supply by the world's producers – primarily by members of OPEC – led to stronger oil prices. Due to economic slowdowns in many major countries during 2001, crude oil demand softened leading to significantly weaker sales prices. In response to lower oil prices, OPEC and other major oil producers have agreed to reduce oil production in early 2002. It is too early to determine whether these production cuts will lead to a meaningful improvement in oil prices. Due to a combination of warmer than normal weather across much of North America during the early winter of 2001-2002 and increased gas storage levels, the price of natural gas in early 2002 remained below trading ranges during most of the last two years. In addition, refined product margins in both the United States and United Kingdom were extremely weak in early 2002, leading to losses in refining and marketing operations in both areas. If oil and natural gas sales prices and refining and marketing margins continue at the levels experienced in January 2002, the Company expects that future operating results could be near break-even. In such a volatile operating environment, constant reassessment of spending plans is required.

The Company's capital expenditure budget for 2002 was prepared during the fall of 2001 and provides for expenditures of $866 million. Of this amount, $604 million or 70%, is allocated for exploration and production. Geographically, 39% of the exploration and production budget is allocated to the United States, including $139 million for development of deepwater projects in the Gulf of Mexico; another 36% is allocated to Canada, including $41 million for light oil and natural gas development, $28 million for continued development of the Hibernia and Terra Nova oil fields, and $49 million for further expansion of synthetic oil operations; 6% is allocated to the United Kingdom; 5% is allocated to Ecuador; and 14% is allocated to other foreign operations, which primarily includes Malaysia. Budgeted refining and marketing capital expenditures for 2002 are $259 million, including $235 million in the United States, and $12 million each in the United Kingdom and Canada. U.S. and Canadian amounts include funds to build additional stations at Wal-Mart sites. U.S. amounts also include spending for clean fuels and crude throughput expansion projects at the Meraux refinery. Due to an expectation of lower natural gas sales prices compared to the price assumptions used in the 2002 Budget, the Company has announced intentions to reduce 2002 capital expenditures by approximately $100 million. Capital and other expenditures are under constant review and planned capital expenditures may be adjusted further to reflect changes in estimated cash flow during 2002.

Based on the Company's projected capital expenditures in 2002 and weaker than anticipated natural gas sales prices and refining and marketing margins early in the year, a significant portion of capital expenditures is anticipated to be funded through new long-term borrowings during the year. Murphy's 2002 Budget anticipates an increase in long-term debt of approximately $300 million during the year. Although the Company is actively managing capital expenditures in light of anticipated lower operating cash flows, it is possible that long-term debt could exceed the budgeted year-end 2002 levels, especially if cash flows continue to be adversely affected in upcoming months by low natural gas sales prices and weak refining and marketing margins such as those experienced in early 2002.

Forward-Looking Statements

This Form 10-K report, including documents incorporated by reference herein, 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.

At December 31, 2001, the Company was a party to interest rate swaps with notional amounts totaling $100 million that were designed to hedge fluctuations in cash flows of a similar amount of variable-rate debt. These swaps mature in 2002 and 2004. The swaps require the Company to pay an average interest rate of 6.46% over their composite lives, and at December 31, 2001, the interest rate to be received by the Company averaged 2.28%. 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. As described in Note K to the consolidated financial statements, the estimated fair value of these interest rate swaps was a loss of $4.3 million at December 31, 2001.

At December 31, 2001, 26% of the Company's debt had variable interest rates and 9% was denominated in Canadian dollars. Based on debt outstanding at December 31, 2001, a 10% increase in variable interest rates would have an insignificant impact on the Company's interest expense for the next 12 months after including the favorable effect resulting from lower net settlement payments under the aforementioned interest rate swaps. A 10% increase in the exchange rate of the Canadian dollar versus the U.S. dollar would increase interest expense in 2002 by $.1 million for debt denominated in Canadian dollars.

Murphy was a party to natural gas price swap agreements at December 31, 2001 for a total notional volume of 7.7 million British Thermal Units (MMBTU) that are intended to hedge a portion of the financial exposure of its Meraux, Louisiana refinery to fluctuations in the future price of natural gas purchased for fuel. In each month of settlement, the swaps require Murphy to pay an average natural gas price of $2.68 per MMBTU and to receive the average NYMEX price for the final three trading days of the month. At December 31, 2001, the estimated fair value of these agreements was recorded as an asset of $4.3 million. A 10% increase in the average NYMEX price of natural gas would have increased this asset by $2.1 million, while a 10% decrease would have reduced the asset by a similar amount.

In addition, the Company was a party to natural gas swap agreements at December 31, 2001 that are intended to hedge the financial exposure of a limited portion of its U.S. natural gas production to changes in gas sales prices through March 2002. The swaps are for a notional volume that averages 32,000 MMBTU per day in the first quarter of 2002 and require Murphy to pay the average NYMEX price for the final trading day of each month and receive a price ranging from $2.54 to $2.94 per MMBTU. At December 31, 2001, the estimated fair value of these agreements was recorded as an asset of $.8 million. A 10% increase in the average NYMEX price of natural gas would have reduced this asset by $.7 million, while a 10% decrease would have increased the asset by a similar amount.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages F-1 through F-34, which follow page 23 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 8, 2002 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 8, 2002 under the captions "Compensation of Directors," "Executive Compensation," "Option Exercises and Fiscal Year-End Values," "Option Grants," "Compensation Committee Report for 2001," "Shareholder Return Performance Presentation" and "Retirement Plans."

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information required by this item is incorporated by reference to the Registrant's definitive Proxy Statement for the Annual Meeting of Stockholders on May 8, 2002 under the captions "Security Ownership of Certain Beneficial Owners" and "Security Ownership of Management."

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

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

2. **Financial Statement Schedules**

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

3. **Exhibits** – The following is an index of exhibits that are hereby filed as indicated by asterisk (*), 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 February 7, 2001	Exhibit 3.2 of Murphy's Form 10-K report for the year ended December 31, 2000
4	Instruments Defining the Rights of Security Holders. Murphy is party to several long-term debt instruments in addition to the one in Exhibit 4.1, none of which authorizes securities exceeding 10% of the total consolidated assets of Murphy and its subsidiaries. Pursuant to Regulation S-K, item 601(b), paragraph 4(iii)(A), Murphy agrees to furnish a copy of each such instrument to the Securities and Exchange Commission upon request.	
4.1	Form of Indenture and Form of Supplemental Indenture between Murphy Oil Corporation and SunTrust Bank, Nashville, N.A., 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
4.2	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

4.3	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
4.4	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	Exhibit 10.2 of Murphy's Form 10-Q report for the quarterly period ended June 30, 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
*13	2001 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	Form 11-K, Annual Report for the fiscal year ended December 31, 2001 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, 2001
#99.3	Form 11-K, Annual Report for the fiscal year ended December 31, 2001 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, 2001
#99.4	Form 11-K, Annual Report for the fiscal year ended December 31, 2001 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, 2001

(b) Reports on Form 8-K

No reports on Form 8-K were filed during the quarter ended December 31, 2001.

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 22, 2002

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on March 22, 2002 by the following persons on behalf of the registrant and in the capacities indicated.

R. MADISON MURPHY
R. Madison Murphy, Chairman and Director

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

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

WILLIAM L. ROSOFF
William L. Rosoff, Director

B. R. R. BUTLER
B. R. R. Butler, Director

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)

MICHAEL W. MURPHY
Michael W. Murphy, Director

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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 and objective 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 dated May 10, 2000. 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, 2001 and 2000, 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, 2001. 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, 2001 and 2000, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2001, 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, 2001, the Company changed its method of accounting for derivative instruments and hedging activities.

Shreveport, Louisiana
February 1, 2002

KPMG LLP

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 (Thousands of dollars except per share amounts)	2001	2000	1999
Revenues			
Crude oil and natural gas sales	$ 832,510	751,498	470,643
Petroleum product sales	2,783,617	2,731,988	1,515,537
Crude oil trading sales	605,143	1,041,524	705,969
Other operating revenues	245,551	89,331	59,934
Interest and other nonoperating revenues	11,688	24,824	4,358
Total revenues	4,478,509	4,639,165	2,756,441
Costs and Expenses			
Crude oil, products and related operating expenses	3,456,021	3,704,936	2,198,701
Exploration expenses, including undeveloped lease amortization	156,919	125,629	70,557
Selling and general expenses	97,835	85,474	81,817
Depreciation, depletion and amortization	229,222	213,539	205,077
Amortization of goodwill	3,120	–	–
Impairment of properties	10,478	27,916	–
Provision for reduction in force	–	–	1,513
Interest expense	39,289	29,936	28,139
Interest capitalized	(20,283)	(13,599)	(7,865)
Total costs and expenses	3,972,601	4,173,831	2,577,939
Income before income taxes and cumulative effect of accounting change	505,908	465,334	178,502
Income tax expense	175,005	159,773	58,795
Income before cumulative effect of accounting change	330,903	305,561	119,707
Cumulative effect of accounting change, net of tax (Note B)	–	(8,733)	–
Net Income	$ 330,903	296,828	119,707
Income (Loss) per Common Share – Basic			
Before cumulative effect of accounting change	$ 7.32	6.78	2.66
Cumulative effect of accounting change	–	(.19)	–
Net Income – Basic	7.32	6.59	2.66
Income (Loss) per Common Share – Diluted			
Before cumulative effect of accounting change	$ 7.26	6.75	2.66
Cumulative effect of accounting change	–	(.19)	–
Net Income – Diluted	7.26	6.56	2.66
Average Common shares outstanding – basic	45,221,472	45,031,665	44,970,457
Average Common shares outstanding – diluted	45,590,999	45,239,706	45,030,225

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

December 31 (Thousands of dollars)	2001	2000
Assets		
Current assets		
Cash and cash equivalents	$ 82,652	132,701
Accounts receivable, less allowance for doubtful accounts of $11,263 in 2001 and $10,208 in 2000	262,022	469,616
Inventories, at lower of cost or market		
Crude oil and blend stocks	38,917	47,875
Finished products	85,133	68,464
Materials and supplies	49,098	48,416
Prepaid expenses	61,062	23,949
Deferred income taxes	19,777	25,916
Total current assets	598,661	816,937
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $3,277,673 in 2001 and $3,144,369 in 2000	2,525,807	2,184,719
Goodwill, net	50,412	48,396
Deferred charges and other assets	84,219	84,301
Total assets	$ 3,259,099	3,134,353
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long-term debt	$ 48,250	37,242
Accounts payable	325,323	528,416
Income taxes	48,378	68,343
Other taxes payable	86,844	65,262
Other accrued liabilities	51,262	45,964
Total current liabilities	560,057	745,227
Notes payable	416,061	398,375
Nonrecourse debt of a subsidiary	104,724	126,384
Deferred income taxes	302,868	229,968
Accrued dismantlement costs	160,764	160,049
Accrued major repair costs	44,570	34,302
Deferred credits and other liabilities	171,892	180,488
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, 2001 and 80,000,000 shares at December 31, 2000, issued 48,775,314 shares	48,775	48,775
Capital in excess of par value	527,126	514,474
Retained earnings	1,096,567	833,490
Accumulated other comprehensive loss	(83,309)	(38,266)
Unamortized restricted stock awards	(968)	(1,410)
Treasury stock	(90,028)	(97,503)
Total stockholders' equity	1,498,163	1,259,560
Total liabilities and stockholders' equity	$ 3,259,099	3,134,353

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)	2001	2000	1999
Operating Activities			
Income before cumulative effect of accounting change	$ 330,903	305,561	119,707
Adjustments to reconcile above income to net cash provided by operating activities			
Depreciation, depletion and amortization	229,222	213,539	205,077
Impairment of properties	10,478	27,916	–
Provisions for major repairs	21,070	22,761	18,721
Expenditures for major repairs and dismantlement costs	(16,395)	(16,603)	(44,096)
Dry hole costs	82,825	65,987	32,422
Amortization of undeveloped leases	23,154	14,076	10,968
Amortization of goodwill	3,120	–	–
Deferred and noncurrent income tax charges	80,052	63,431	38,027
Pretax gains from disposition of assets	(105,504)	(4,010)	(11,940)
Net (increase) decrease in noncash operating working capital excluding acquisition of Beau Canada Exploration Ltd.	(27,951)	66,002	(35,159)
Cumulative effect of accounting change on working capital	–	(11,170)	–
Other operating activities – net	4,730	261	7,984
Net cash provided by operating activities	635,704	747,751	341,711
Investing Activities			
Property additions and dry hole costs	(813,500)	(512,331)	(359,438)
Acquisition of Beau Canada Exploration Ltd., net of cash acquired	–	(127,476)	–
Proceeds from sale of property, plant and equipment	172,972	20,705	40,871
Other investing activities – net	(1,410)	391	(3,532)
Net cash required by investing activities	(641,938)	(618,711)	(322,099)
Financing Activities			
Additions to notes payable	87,000	175,000	247,776
Reductions of notes payable	(62,214)	(124,254)	(190,806)
Additions to nonrecourse debt of a subsidiary	1,241	–	–
Reductions of nonrecourse debt of a subsidiary	(15,499)	(6,207)	(5,120)
Proceeds from exercise of stock options and employee stock purchase plans	18,864	3,769	2,269
Cash dividends paid	(67,826)	(65,294)	(62,950)
Other financing activities – net	(3,050)	(7,894)	(4,011)
Net cash required by financing activities	(41,484)	(24,880)	(12,842)
Effect of exchange rate changes on cash and cash equivalents	(2,331)	(5,591)	(909)
Net increase (decrease) in cash and cash equivalents	(50,049)	98,569	5,861
Cash and cash equivalents at January 1	132,701	34,132	28,271
Cash and cash equivalents at December 31	$ 82,652	132,701	34,132

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)	2001	2000	1999
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	$ –	–	–
Common Stock – par $1.00, authorized 200,000,000 shares at December 31, 2001 and 80,000,000 shares at December 31, 2000 and 1999, issued 48,775,314 shares at beginning and end of each year	48,775	48,775	48,775
Capital in Excess of Par Value			
Balance at beginning of year	514,474	512,488	510,116
Exercise of stock options, net of income taxes	10,440	1,749	797
Restricted stock transactions	1,272	(202)	1,344
Sale of stock under employee stock purchase plans	940	439	231
Balance at end of year	527,126	514,474	512,488
Retained Earnings			
Balance at beginning of year	833,490	601,956	545,199
Net income for the year	330,903	296,828	119,707
Cash dividends – $1.50 per share in 2001, $1.45 per share in 2000 and $1.40 per share in 1999	(67,826)	(65,294)	(62,950)
Balance at end of year	1,096,567	833,490	601,956
Accumulated Other Comprehensive Loss			
Balance at beginning of year	(38,266)	(4,984)	(23,520)
Foreign currency translation gains (losses)	(49,596)	(33,282)	18,536
Cash flow hedging gains, net of income taxes	4,553	–	–
Balance at end of year	(83,309)	(38,266)	(4,984)
Unamortized Restricted Stock Awards			
Balance at beginning of year	(1,410)	(2,328)	(2,361)
Amortization, forfeitures and changes in price of Common Stock	442	918	33
Balance at end of year	(968)	(1,410)	(2,328)
Treasury Stock			
Balance at beginning of year	(97,503)	(98,735)	(99,976)
Exercise of stock options	6,833	1,140	704
Awarded restricted stock, net of forfeitures	(9)	(349)	–
Sale of stock under employee stock purchase plans	651	441	537
Balance at end of year – 3,444,234 shares of Common Stock in 2001, 3,729,769 shares in 2000 and 3,777,319 shares in 1999	(90,028)	(97,503)	(98,735)
Total Stockholders' Equity	$ 1,498,163	1,259,560	1,057,172

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)		**2001**	**2000**	**1999**
Net income	$	330,903	296,828	119,707
Other comprehensive income (loss), net of tax				
Cash flow hedges				
Net derivative gains		26	–	–
Reclassification adjustments		(2,115)	–	–
Total cash flow hedges		(2,089)	–	–
Net gain (loss) from foreign currency translation		(49,596)	(33,282)	18,536
Other comprehensive income (loss) before cumulative effect of accounting change		(51,685)	(33,282)	18,536
Cumulative effect of accounting change (Note B)		6,642	–	–
Other comprehensive income (loss)		(45,043)	(33,282)	18,536
Comprehensive Income	$	285,860	263,546	138,243

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 the United States 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 associated with sales of refined products and the Company's share of crude oil production are recorded when title passes to the customer. The Company uses the sales method to record revenues associated with oil and natural gas production. The Company records a liability for natural gas balancing when the Company has sold more than its working interest share of natural gas production and the estimated remaining reserves make it doubtful that partners can recoup their share of production from the field. At December 31, 2001 and 2000, the liabilities for gas balancing arrangements 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.

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 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-28 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.

Murphy accrues in advance for estimated costs of major repairs by recording monthly expense provisions for turnarounds of refineries and a synthetic oil upgrading facility. 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 can no longer be amortized. SFAS 142 requires an annual assessment of recoverability of the carrying value of goodwill. Beginning in 2002, the Company will assess 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 this assessment indicate that goodwill is not fully recoverable, an impairment charge to write down the carrying value of goodwill must be recorded.

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 133, as amended by SFAS 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.

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

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

Note B – New Accounting Principles and Recent Accounting Pronouncements

Effective January 1, 2001, Murphy was required to adopt SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS No. 138. Under SFAS Nos. 133/138, Murphy records the fair values of its derivative instruments as either assets or liabilities. Adoption of SFAS Nos. 133/138 resulted in a transition adjustment gain to Accumulated Other Comprehensive Loss (AOCL) of $6.6 million, net of $2.8 million in income taxes, for the cumulative effect on prior years; there was no cumulative effect on earnings. Excluding the transition adjustment, the effect of this accounting change decreased AOCL for the year ended December 31, 2001 by $2.1 million, net of $.4 million in income taxes, and decreased net income for the year by $.1 million, net of taxes. During the year ended December 31, 2001, losses of $2.1 million, net of $.8 million in income taxes, associated with the transition adjustment were reclassified from AOCL to earnings.

In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, *Business Combinations*, requiring 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. The Company adopted SFAS No. 141 immediately.

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 prior years' revenue of $20,591,000. Pro forma net income for the years ended December 31, 2000 and 1999, assuming that the new revenue recognition method had been applied retroactively in each year, was as follows.

(Thousands of dollars except per share data)		**2000**	**1999**
Net income	– As reported	$ 296,828	119,707
	Pro forma	305,561	111,336
Net income per share	– As reported, basic	$ 6.59	2.66
	Pro forma, basic	6.78	2.48
	As reported, diluted	6.56	2.66
	Pro forma, diluted	6.75	2.47

In July 2001, the FASB issued 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. The Company will adopt SFAS No. 142 on January 1, 2002. The Company's unamortized goodwill of $50,412,000 at December 31, 2001 will be subject to the transition provisions of SFAS No. 142.

In July 2001, the FASB also 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.

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 will adopt the provisions of SFAS No. 144 effective January 1, 2002, and its provisions are generally to be applied prospectively.

At this time, it is not practicable to reasonably estimate the impact of adopting SFAS Nos. 142, 143 and 144 on the Company's financial statements, including whether any transitional goodwill impairment losses will be required to be recognized as the cumulative effect of a change in accounting principle.

Note C – 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 a 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 certain 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 F). 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 and 1999. The pro forma financial information is not necessarily indicative of the operating results that would have occurred had the acquisition been consummated as of the dates indicated, nor is it necessarily indicative of future operating results.

	Years Ended December 31,	
(Thousands of dollars except per share data)	**2000**	**1999**
Pro forma revenues	$ 4,727,574	2,830,973
Pro forma net income	303,479	121,011
Pro forma net income per Common share – diluted	6.71	2.69

Note D – Property, Plant and Equipment

	December 31, 2001		December 31, 2000	
(Thousands of dollars)	**Cost**	**Net**	**Cost**	**Net**
Exploration and production	$ 4,553,034	1,885,124*	4,156,422	1,616,424*
Refining	795,742	319,813	710,623	256,469
Marketing	377,721	289,344	307,429	224,677
Transportation	33,396	4,314	111,409	62,210
Corporate and other	43,587	27,212	43,205	24,939
	$ 5,803,480	2,525,807	5,329,088	2,184,719

*Includes $20,174 in 2001 and $17,370 in 2000 related to administrative assets and support equipment.

In the 2001 and 2000 Consolidated Statements of Income, the Company recorded noncash charges of $10,478,000 and $27,916,000 respectively, for impairment of certain properties. After related income tax benefits, these write-downs reduced net income by $6,811,000 in 2001 and $17,817,000 in 2000. The charges related to natural gas fields in the Gulf of Mexico and Canadian heavy oil properties. The U.S. impairments were all caused by downward reserve revisions for poor well performance of natural gas fields. The Canadian heavy oil impairment was due to a downward reserve revision for one field and high operating costs on another field. The carrying value of impaired properties were reduced to the asset's fair value based on projected future discounted net cash flows, using the Company's estimate of future commodity prices.

Note E – Financing Arrangements

At December 31, 2001, the Company had three unused committed credit facilities with a major banking consortium totaling US $450,000,000. 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 $150,000,000 one-year revolving credit agreement maturing in December 2002 with an option to convert any outstanding amounts to a one-year term loan at maturity. The Company's Canadian subsidiary has available a $150,000,000 one-year revolving agreement with an option to convert any outstanding amounts to a five-year term at maturity. The two one-year revolving credit agreements are extendable for up to one year upon approval of a majority of the banking consortium. U.S. dollar and Canadian dollar commercial paper totaling an equivalent US $96,476,000 at December 31, 2001 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, 2001 totaling an equivalent US $192,602,000 for a combination of U.S. dollar and Canadian dollar borrowings. At December 31, 2001, US $50,000,000 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 $1 billion in debt and equity securities. No securities had been issued under this shelf registration as of December 31, 2001.

Note F – Long-term Debt

December 31 (Thousands of dollars)	**2001**	**2000**
Notes payable		
7.05% notes, due 2029, net of unamortized discount of $2,539 at December 31, 2001	$ 247,461	247,369
6.23% structured loan, due 2002-2005	149,832	175,000
Notes payable to bank, 2.30% to 2.90%, due 2002	50,000	–
Other, 6% to 8%, due 2002-2021	1,187	1,244
Total notes payable	448,480	423,613
Nonrecourse debt of a subsidiary		
Guaranteed credit facilities with banks		
Commercial paper, 2.075% to 2.275%, $27,076 payable in Canadian dollars, supported by credit facility, due 2002-2008	96,476	110,633
Loans payable to Canadian government, interest free, payable in Canadian dollars, due 2002-2008	24,079	27,755
Total nonrecourse debt of a subsidiary	120,555	138,388
Total debt including current maturities	569,035	562,001
Current maturities	(48,250)	(37,242)
Total long-term debt	$ 520,785	524,759

Maturities for the four years after 2002 are: $50,536,000 in 2003, $52,488,000 in 2004, $62,194,000 in 2005 and $65,879,000 in 2006.

Notes payable to bank due in 2002 have been classified as long-term debt since the borrowing is capable of being refinanced 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. Beginning in 2001, 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 G – Provision for Reduction in Force

In 1999 the Company offered enhanced voluntary retirement benefits to eligible exploration, production and administrative employees in its New Orleans and Calgary offices and severed certain other employees at these locations. The voluntary retirements and severances reduced the Company's workforce by 31 employees, and a charge of $1,513,000 was recorded to income in 1999. The provision included additional defined benefit plan expense of $1,041,000 and severance and other costs of $472,000, the latter of which was essentially all paid during 1999.

Note H – Income Taxes

The components of income before income taxes and cumulative effect of accounting change for each of the three years ended December 31, 2001 and income tax expense (benefit) attributable thereto were as follows.

(Thousands of dollars)		**2001**	**2000**	**1999**
Income before income taxes and cumulative effect of accounting change				
United States		$ 161,056	102,519	15,074
Foreign		344,852	362,815	163,428
		$ 505,908	465,334	178,502
Income tax expense (benefit) before cumulative effect of accounting change				
Federal –	Current[1]	$ 30,153	19,215	(13,497)
	Deferred	33,167	5,665	1,597
	Noncurrent	(4,136)	(2,261)	16,366
		59,184	22,619	4,466
State –	Current	4,710	3,129	1,342
Foreign –	Current	60,090	76,184	40,726
	Deferred[2]	50,916	59,776	11,165
	Noncurrent	105	(1,935)	1,096
		111,111	134,025	52,987
Total		$ 175,005	159,773	58,795

[1]Net of benefit of $3,150 in 2000 for alternative minimum tax credits.
[2]Net of benefits of $5,540 in 2001 for a reduction in a provincial tax rate in Canada and $609 in 1999 for a reduction in the U.K. tax rate.

In 2001, income tax benefits attributable to employee stock option transactions of $1,685,000 were included in Capital in Excess of Par Value in the Consolidated Balance Sheet and income tax charges of $2,447,000 relating to derivatives were included in AOCL.

Total income tax expense in 2000, including tax benefits associated with the cumulative effect of accounting change, was $155,887,000.

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 before cumulative effect of accounting change.

(Thousands of dollars)	**2001**	**2000**	**1999**
Income tax expense based on the U.S. statutory tax rate	$ 177,068	162,867	62,475
Foreign income subject to foreign taxes at a rate different than the U.S. statutory rate	2,498	13,010	1,988
State income taxes	3,062	2,034	872
Settlement of U.S. taxes	(1,446)	(17,016)	(5,000)
Settlement of foreign taxes	(1,915)	–	–
Reduction in provincial tax rate in Canada	(5,540)	–	–
Other, net	1,278	(1,122)	(1,540)
Total	$ 175,005	159,773	58,795

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2001 and 2000 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	2001	2000
Deferred tax assets		
Property and leasehold costs	$ 72,390	70,570
Liabilities for dismantlements and major repairs	68,755	63,754
Postretirement and other employee benefits	29,345	27,950
Foreign tax operating losses	26,844	27,888
Other deferred tax assets	22,029	26,681
Total gross deferred tax assets	219,363	216,843
Less valuation allowance	(67,745)	(60,958)
Net deferred tax assets	151,618	155,885
Deferred tax liabilities		
Property, plant and equipment	(53,494)	(45,860)
Accumulated depreciation, depletion and amortization	(343,925)	(285,444)
Other deferred tax liabilities	(37,290)	(28,633)
Total gross deferred tax liabilities	(434,709)	(359,937)
Net deferred tax liabilities	$ (283,091)	(204,052)

At December 31, 2001, the Company had tax losses and other carryforwards of $98,231,000 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 2002 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 $6,787,000 and $3,570,000 in 2001 and 2000, 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 $29,463,000 related to undistributed earnings of certain foreign subsidiaries at December 31, 2001 because the earnings are considered permanently invested.

Tax returns are subject to audit by various taxing authorities. In 2001, 2000 and 1999, the Company recorded benefits to income of $3,361,000, $25,618,000 and $5,000,000, 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% (.5% prior to 2000) 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 $1,892,000 in 2001, $7,914,000 in 2000 and $13,161,000 in 1999. Outstanding awards were not significantly modified in the last three years.

Had compensation cost of the Plan been based on the fair value of the instruments at the date of grant using the provisions of Statement of Financial Accounting Standards (SFAS) No. 123, the Company's net income and earnings per share would be the pro forma amounts shown in the following table. The pro forma effects on net income in the table may not be representative of the pro forma effects on net income of future years because the SFAS No. 123 provisions used in these calculations were only applied to stock options and restricted stock granted after 1994.

(Thousands of dollars except per share data)		2001	2000	1999
Net income	– As reported	$ 330,903	296,828	119,707
	Pro forma	324,358	299,031	124,543
Net income per share	– As reported, basic	$ 7.32	6.59	2.66
	Pro forma, basic	7.17	6.64	2.77
	As reported, diluted	7.26	6.56	2.66
	Pro forma, diluted	7.12	6.61	2.76

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 FMV at date of grant, except for certain 1997 grants with option prices above FMV. Generally, one-half of each grant may be exercised after two years and the remainder after three years.

The pro forma net income calculations in the preceding table reflect the following fair values of options granted in 2001, 2000 and 1999; fair values of options have been estimated by using the Black-Scholes pricing model and the assumptions as shown.

	2001	2000	1999
Fair value per share at grant date	$ 14.40	$ 15.00	$ 7.76
Assumptions			
Dividend yield	2.84%	2.91%	2.87%
Expected volatility	26.34%	26.06%	24.21%
Risk-free interest rate	4.93%	6.76%	4.77%
Expected life	5 yrs.	5 yrs.	5 yrs.

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

	Number of Shares	Average Exercise Price
Outstanding at December 31, 1998	1,053,249	$ 48.73
Granted at FMV	325,500	35.69
Exercised	(109,130)	39.57
Forfeited	(15,250)	45.27
Outstanding at December 31, 1999	1,254,369	46.19
Granted at FMV	396,000	56.97
Exercised	(192,549)	43.63
Forfeited	(5,250)	49.75
Outstanding at December 31, 2000	1,452,570	49.45
Granted at FMV	518,000	61.66
Exercised	(261,200)	47.28
Outstanding at December 31, 2001	1,709,370	53.48
Exercisable at December 31, 1999	441,119	$ 45.36
Exercisable at December 31, 2000	590,820	51.80
Exercisable at December 31, 2001	635,120	49.13

Additional information about stock options outstanding at December 31, 2001 is shown below.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices Per Share	**No. of Options**	**Avg. Life in Years**	**Avg. Price**	**No. of Options**	**Avg. Price**
$34.56 to $42.25	352,370	6.0	$ 36.74	192,120	$ 37.61
$49.75 to $56.97	717,000	7.0	54.19	321,000	50.76
$60.45 to $65.49	640,000	8.3	61.91	122,000	62.97
	1,709,370	7.3	53.48	635,120	49.13

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. Changes in restricted stock outstanding were as follows.

(Number of shares)	**2001**	**2000**	**1999**
Balance at beginning of year	58,333	83,364	83,364
Awarded	–	(12,077)	–
Forfeited	(750)	(12,954)	–
Balance at end of year	57,583	58,333	83,364

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 $11,816,000, $6,970,000 and $5,301,000 was recorded in 2001, 2000 and 1999, respectively, for these plans.

EMPLOYEE STOCK PURCHASE PLAN (ESPP) – The Company has an ESPP under which 150,000 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 150,000 shares or June 30, 2007. Employee stock purchases under the ESPP were 16,828 shares at an average price of $60.71 per share in 2001, 13,675 shares at $51.08 in 2000 and 20,487 shares at $37.56 in 1999. At December 31, 2001, 83,369 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. 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, 2001 and 2000 and a statement of the funded status as of December 31, 2001 and 2000.

	Pension Benefits		Postretirement Benefits	
(Thousands of dollars)	**2001**	**2000**	**2001**	**2000**
Change in benefit obligation				
Obligation at January 1	$ 247,718	240,630	38,454	34,350
Service cost	5,757	5,461	935	753
Interest cost	17,370	17,010	3,009	2,699
Plan amendments	–	3,501	–	–
Participant contributions	71	–	551	566
Actuarial loss	8,811	1,203	4,311	3,219
Settlements	(1,660)	(2,257)	–	–
Exchange rate changes	(1,773)	(3,461)	–	–
Benefits paid	(15,112)	(14,369)	(3,925)	(3,133)
Obligation at December 31	261,182	247,718	43,335	38,454
Change in plan assets				
Fair value of plan assets at January 1	300,203	304,474	–	–
Actual return on plan assets	(25,379)	15,393	–	–
Employer contributions	1,089	687	3,374	2,567
Participant contributions	71	–	551	566
Settlements	(1,924)	(2,271)	–	–
Exchange rate changes	(2,076)	(3,711)	–	–
Benefits paid	(15,112)	(14,369)	(3,925)	(3,133)
Fair value of plan assets at December 31	256,872	300,203	–	–
Reconciliation of funded status				
Funded status at December 31	(4,310)	52,485	(43,335)	(38,454)
Unrecognized actuarial (gain) loss	35,809	(22,440)	10,505	6,594
Unrecognized transition asset	(9,091)	(13,047)	–	–
Unrecognized prior service cost	6,956	7,806	–	–
Net plan asset (liability) recognized	$ 29,364	24,804	(32,830)	(31,860)
Amounts recognized in the Consolidated Balance Sheets at December 31				
Prepaid benefit asset	$ 45,454	40,152	–	–
Accrued benefit liability	(17,310)	(17,051)	(32,830)	(31,860)
Intangible asset	1,220	1,703	–	–
Net plan asset (liability) recognized	$ 29,364	24,804	(32,830)	(31,860)

At December 31, 2001 and 2000, accumulated benefit obligations for nonqualified and directors' retirement plans that are not funded were $10,541,000 and $10,060,000, respectively. Due to declines in the market value of plan assets during the year, certain funded retirement plans had accumulated benefit obligations in excess of plan assets at year-end 2001; these plans had obligations of $55,794,000 and assets of $54,223,000. At December 31, 2001 and 2000, the accumulated benefit obligations for the Company's postretirement benefit plans, which are not funded, amounted to $43,335,000 and $38,454,000, respectively.

The table that follows provides the components of net periodic benefit expense (credit) for each of the three years ended December 31, 2001.

	Pension Benefits			Postretirement Benefits		
(Thousands of dollars)	**2001**	**2000**	**1999**	**2001**	**2000**	**1999**
Service cost	$ 5,757	5,461	5,791	935	753	712
Interest cost	17,370	17,010	15,516	3,009	2,699	2,366
Expected return on plan assets	(24,123)	(24,412)	(23,105)	–	–	–
Amortization of prior service cost	782	791	622	–	–	–
Amortization of transitional asset	(2,552)	(2,585)	(2,204)	–	–	–
Recognized actuarial (gain) loss	(181)	(395)	(766)	400	234	203
	(2,947)	(4,130)	(4,146)	4,344	3,686	3,281
Settlement gain	(901)	(1,824)	–	–	–	–
Special early retirement benefits	–	–	1,041	–	–	–
Net periodic benefit expense (credit)	$ (3,848)	(5,954)	(3,105)	4,344	3,686	3,281

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 include the following amounts related to foreign benefit plans.

	Pension Benefits		Postretirement Benefits	
(Thousands of dollars)	**2001**	**2000**	**2001**	**2000**
Benefit obligation at December 31	$ 49,010	49,608	–	–
Fair value of plan assets at December 31	46,709	55,473	–	–
Net plan asset (liability) recognized	73	(876)	–	–
Net periodic benefit credit	(704)	(1,960)	–	–

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2001 and 2000.

	Pension Benefits		Postretirement Benefits	
	2001	**2000**	**2001**	**2000**
Discount rate	7.00%	7.25%	7.25%	7.50%
Expected return on plan assets	8.30%	8.33%	–	–
Rate of compensation increase	4.59%	4.63%	–	–

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, 2001, the future annual rates of increase in the cost of health care were assumed to be 7.5% for 2002 decreasing .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, 2001	$ 257	(240)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 2001	2,280	(2,184)

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 savings plan was 8,068 shares in 2001 and 3,180 shares in 2000. Amounts charged to expense for these plans were $4,061,000 in 2001, $3,699,000 in 2000 and $2,523,000 in 1999.

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 trading 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 limit its exposure to interest rate risk, Murphy has interest rate swap agreements with notional amounts totaling $100,000,000 to hedge fluctuations in cash flows of a similar amount of variable rate debt. The swaps mature in 2002 and 2004. Under the interest rate swaps, the Company pays fixed rates averaging 6.46% over their composite lives and receives variable rates which averaged 2.28% at December 31, 2001. 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 as a rate adjustment in the periods in which the hedged interest payments on the variable-rate debt affect earnings. For the year ended December 31, 2001, the income effect from cash flow hedging ineffectiveness 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. The cost of natural gas is subject to commodity price risk. Murphy has reduced the effect of changes in the price of natural gas used for fuel at Meraux by entering into natural gas swap contracts with a notional volume of 7.7 million British Thermal Units (MMBTU) to hedge fluctuations in cash flows resulting from such risk during 2004 and 2005.

  Under the natural gas swaps, the Company pays a fixed rate averaging $2.68 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 fuel requirements and to Murphy's natural gas swaps. The control system involves using analytical techniques, including various correlations of natural gas purchase prices to futures 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, Products and Related Operating Expenses in the periods in which the hedged natural gas fuel purchases affect earnings. For the year ended December 31, 2001, the income effect from cash flow hedging ineffectiveness 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 minimized the effect of changes in the selling price of a portion of its U.S. natural gas production through March 2002 by entering into natural gas swap contracts to hedge cash flow fluctuations resulting from such risk. The natural gas swaps are for a notional volume averaging approximately 32,000 MMBTU per day in the first quarter of 2002 and require Murphy to pay the average NYMEX price for the final trading day of each month and receive a price ranging from $2.54 to $2.94 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 require 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 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 changes thereto are deferred in AOCL and are subsequently reclassified into Crude Oil and Natural Gas Sales in the periods in which the hedged natural gas sales affect earnings. For the year ended December 31, 2001, Murphy's earnings were not significantly impacted from cash flow hedging ineffectiveness arising from the natural gas swaps in the United States and western Canada.

  The fair value of the natural gas fuel swaps and the natural gas sales swaps are both based on the average fixed price of the swaps and the published NYMEX futures price or natural gas 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 purchased 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 by receiving $5,806,000 in cash and entered into offsetting contracts for the remaining swap agreements, locking in an additional future net gain of $1,929,000. The fair values of these settlement gains were recorded in AOCL as part of the transition adjustment and are recognized as a reduction of costs of crude oil purchases in the period the forecasted transaction occurs. During 2001, pretax gains of $1,957,000 were reclassified from AOCL into earnings. Approximately $5,778,000 of gains will be reclassified from AOCL into earnings during 2002.

  The fair value of the offsetting crude oil swap contracts is based on the fixed swap price and the NYMEX crude oil futures price.

The Company expects to reclassify approximately $2,300,000 in after-tax gains from AOCL into earnings during the next 12 months as the forecasted transactions actually occur. All forecasted transactions currently being hedged are expected to occur by December 2005.

FAIR VALUE – The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2001 and 2000. 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.

	2001		2000	
(Thousands of dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Financial assets (liabilities):				
Crude oil swaps	$ 1,914	1,914	–	1,793
Natural gas fuel swaps	4,309	4,309	–	6,196
Natural gas sales swaps	842	842	(12,615)	(17,905)
Interest rate swaps	(4,269)	(4,269)	–	(1,956)
Current and long-term debt	(569,035)	(542,115)	(562,001)	(526,891)

The carrying amounts of crude oil swaps, natural gas swaps and interest rate swaps in the preceding table are included in Deferred Charges and Other Assets or Other Accrued Liabilities. Current and long-term debt are included in the Consolidated Balance Sheets 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, 2001. No difference existed between net income used in computing basic and diluted income per Common share for these years.

(Weighted-average shares outstanding)	2001	2000	1999
Basic method	45,221,472	45,031,665	44,970,457
Dilutive stock options	369,527	208,041	59,768
Diluted method	45,590,999	45,239,706	45,030,225

The computations of diluted earnings per share in the Consolidated Statements of Income did not consider outstanding options of 147,000 shares at year-end 2000 and 684,750 shares at year-end 1999 because the effects of these options would have improved the Company's earnings per share. Average exercise prices per share of the options not used were $62.97 and $53.34, respectively. There were no antidilutive options for the year ending 2001.

Note N – *Other Financial Information*

INVENTORIES – Inventories accounted for under the LIFO method totaled $90,464,000 and $85,968,000 at December 31, 2001 and 2000, respectively, and were $51,054,000 and $123,963,000 less than such inventories would have been valued using the FIFO method.

ACCUMULATED OTHER COMPREHENSIVE LOSS – At December 31, 2001 and 2000, the components of Accumulated Other Comprehensive Loss were as follows.

(Thousands of dollars)	2001	2000
Foreign currency translation loss, net	$ (87,862)	(38,266)
Cash flow hedge gains, net	4,553	–
Balance at end of year	$ (83,309)	(38,266)

At December 31, 2001, components of the net foreign currency translation loss of $87,862,000 were gains (losses) of $8,017,000 for pounds sterling, $(96,036,000) for Canadian dollars and $157,000 for other currencies. Comparability of net income was not significantly affected by exchange rate fluctuations in 2001, 2000 and 1999. Net gains (losses) from foreign currency transactions included in the Consolidated Statements of Income were $1,406,000 in 2001, $252,000 in 2000 and $(847,000) in 1999.

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 (refunded) were $135,734,000, $53,583,000 and $(5,343,000) in 2001, 2000 and 1999, respectively. Interest paid, net of amounts capitalized, was $12,945,000, $15,185,000 and $17,140,000 in 2001, 2000 and 1999, respectively.

Noncash operating working capital (increased) decreased for each of the three years ended December 31, 2001 as follows.

(Thousands of dollars)	2001	2000	1999
Accounts receivable	$ 207,594	(95,675)	(123,566)
Inventories	(8,393)	(12,197)	(21,866)
Prepaid expenses	(37,113)	5,794	4,147
Deferred income tax assets	6,139	(4,196)	(8,600)
Accounts payable and accrued liabilities	(176,213)	142,228	99,382
Current income tax liabilities	(19,965)	30,048	15,344
Net (increase) decrease in noncash operating working capital excluding acquisition of Beau Canada	$ (27,951)	66,002	(35,159)

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 $17,600,000 in 2002 to $15,800,000 in 2006. Rental expense for noncancellable operating leases, including contingent payments when applicable, was $23,859,000 in 2001, $17,425,000 in 2000 and $9,800,000 in 1999. Commitments for capital expenditures were approximately $506,000,000 at December 31, 2001, including $206,000,000 related to clean fuels and crude throughput expansion projects at the Meraux refinery and $94,000,000 related to development of the Company's Medusa field in the Gulf of Mexico.

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 refineries, oil and gas fields, service stations, and terminals, for which known or potential obligations for environmental remediation exist.

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 three Superfund sites and has also been assigned responsibility by defendants at another Superfund site. The potential total cost to all parties to perform necessary remedial work at these sites may be substantial. Based on currently available information, the Company believes that it is a *de minimus* party as to ultimate responsibility at the four sites. The Company has not recorded a liability for remedial costs on Superfund sites. The Company could be required to bear a pro rata share of costs attributable to nonparticipating PRPs; additionally, the Company could be assigned additional responsibility for remediation at these or other Superfund sites.

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. The Company does not expect that future costs for these matters will have a material adverse effect on its financial condition.

In June 2000, the U.S. Government filed a lawsuit against Murphy Oil USA, Inc., the Company's wholly-owned subsidiary, in federal court in Madison, Wisconsin, alleging violations of environmental laws at the Company's Superior, Wisconsin refinery. The lawsuit was divided into liability and damage phases, and on August 1, 2001, the court ruled against the Company in the liability phase of the trial. Subsequent to the court ruling, the Company and the U.S. Government reached a tentative agreement that was filed with the federal court in January 2002. The settlement is subject to approval by the court following a 30-day public comment period that expires March 7, 2002. According to the tentative settlement agreement, the Company is to pay a civil penalty of $5.5 million and implement other environmental projects to resolve Clean Air Act violations. The Company has recorded a liability of $5.5 million to cover the penalty. Although the settlement is tentative and no assurance can be given, the Company does not believe that the ultimate resolution of this matter will have a material adverse effect on its financial condition.

Murphy and its subsidiaries are engaged in a number of other legal proceedings, all of which Murphy considers routine and incidental to its business and none of which is expected to have a material adverse effect on the Company's financial condition. The ultimate resolution of environmental and legal matters referred to in this note could have a material adverse effect on the Company's earnings 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, 2001, the Company had contingent liabilities of $33,789,000 under certain financial guarantees and $35,578,000 on outstanding letters of credit. The Company believes that the likelihood of having the guarantees or letters of credit drawn are remote.

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, 2001 is shown below.

(Number of shares outstanding)	2001	2000	1999
At beginning of year	45,045,545	44,997,995	44,950,476
Stock options exercised	261,200	43,678	26,953
Employee stock purchase plans	24,896	16,855	20,487
Restricted stock forfeitures	(750)	(12,954)	–
All other	189	(29)	79
At end of year	45,331,080	45,045,545	44,997,995

Note R – Business Segments

Murphy's reportable segments are organized into two major types of business activities, each subdivided into geographic areas of operations. The Company's exploration and production activity is subdivided into segments for the United States, Canada, the United Kingdom, Ecuador, Malaysia and all other countries; each of these segments derives revenues primarily from the sale of crude oil and natural gas. The refining and marketing segments in the United States and the United Kingdom derive revenues mainly from the sale of petroleum products; the Canadian segment derived revenues primarily from the transportation and trading of crude oil. The company sold its Canadian pipeline and trucking assets in May 2001. 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 $1,005,018,000, $1,052,760,000 and $898,917,000 for the years 2001, 2000 and 1999, 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. Murphy's equity method investments are in companies that transport crude oil and petroleum products. 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-26, 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, 2001							
Segment income (loss)	$ 57.8	85.5	78.6	11.5	(36.1)	(7.3)	190.0
Revenues from external customers	185.6	417.6	194.2	33.4	–	2.2	833.0
Intersegment revenues	54.7	30.1	–	–	–	–	84.8
Interest income	–	–	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–	–	–
Income of equity companies	–	–	–	–	–	–	–
Income tax expense (benefit)	30.7	51.6	44.3	–	–	(1.0)	125.6
Significant noncash charges (credits)							
Depreciation, depletion, amortization	40.3	99.0	37.2	6.4	.5	.3	183.7
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	226.2	287.0	17.9	9.0	9.6	–	549.7
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) before cumulative effect of accounting change	$ 50.3	108.1	90.2	21.1	(10.7)	(6.3)	252.7
Revenues from external customers	205.6	278.6	211.5	51.5	–	2.2	749.4
Intersegment revenues	73.4	106.3	11.6	–	–	–	191.3
Interest income	–	–	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–	–	–
Income of equity companies	–	–	–	–	–	–	–
Income tax expense (benefit)	27.1	66.3	56.2	–	–	–	149.6
Significant noncash charges (credits)							
Depreciation, depletion, amortization	50.2	70.0	41.7	6.8	.4	.1	169.2
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
Year ended December 31, 1999							
Segment income (loss)	$ 35.3	47.0	37.2	22.6	(1.6)	(6.1)	134.4
Revenues from external customers	155.8	164.2	119.0	39.0	–	2.0	480.0
Intersegment revenues	50.6	58.7	23.4	–	–	–	132.7
Interest income	–	–	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–	–	–
Income of equity companies	–	–	–	–	–	–	–
Income tax expense (benefit)	10.3	24.8	24.5	–	–	.5	60.1
Significant noncash charges (credits)							
Depreciation, depletion, amortization	65.1	50.9	42.8	8.0	.1	–	166.9
Provisions for major repairs	–	2.5	–	–	–	–	2.5
Amortization of undeveloped leases	7.0	4.0	–	–	–	–	11.0
Deferred and noncurrent income taxes	12.6	21.3	(3.8)	–	–	1.3	31.4
Additions to property, plant, equipment	60.7	143.0	25.6	7.1	1.1	(1.2)	236.3
Total assets at year-end	391.0	737.9	299.4	60.0	1.3	8.2	1,497.8

Geographic Information (Millions of dollars)	Certain Long-Lived Assets at December 31						
	U.S.	Canada	U.K.	Ecuador	Malaysia	Other	Total
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
1999	687.0	724.4	331.6	53.5	1.0	6.7	1,804.2

Segment Information (Continued) (Millions of dollars)	Refining and Marketing U.S.	U.K.	Canada	Total	Corp. & Other	Consolidated
Year ended December 31, 2001						
Segment income (loss)	$ 64.7	14.1	74.9	153.7	(12.8)	330.9
Revenues from external customers	2,952.4	374.6	306.8	3,633.8	11.7	4,478.5
Intersegment revenues	–	–	.2	–	–	85.0
Interest income	–	–	–	–	11.6	11.6
Interest expense, net of capitalization	–	–	–	–	19.0	19.0
Income of equity companies	.9	–	–	.9	–	.9
Income tax expense (benefit)	41.5	5.0	29.7	76.2	(26.8)	175.0
Significant noncash charges (credits)						
Depreciation, depletion, amortization	36.0	6.1	.9	43.0	2.5	229.2
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	3.9	2.5	(1.4)	5.0	(2.3)	80.1
Additions to property, plant, equipment	162.8	12.4	–	175.2	5.8	730.7
Total assets at year-end	734.4	184.4	–	918.8	189.3	3,259.1
Year ended December 31, 2000						
Segment income (loss) before cumulative effect of accounting change	$ 23.9	23.0	7.6	54.5	(1.7)	305.5
Revenues from external customers	2,842.1	458.2	564.6	3,864.9	24.9	4,639.2
Intersegment revenues	.9	–	.7	1.6	–	192.9
Interest income	–	–	–	–	21.7	21.7
Interest expense, net of capitalization	–	–	–	–	16.3	16.3
Income of equity companies	.6	–	–	.6	–	.6
Income tax expense (benefit)	13.2	11.3	6.9	31.4	(21.2)	159.8
Significant noncash charges (credits)						
Depreciation, depletion, amortization	32.7	5.6	2.6	40.9	3.4	213.5
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	112.0	12.4	29.4	153.8	11.4	706.4
Total assets at year-end	670.4	222.6	125.6	1,018.6	213.2	3,134.4
Year ended December 31, 1999						
Segment income (loss)	$ 1.6	14.0	6.8	22.4	(37.1)	119.7
Revenues from external customers	1,641.4	337.9	292.7	2,272.0	4.4	2,756.4
Intersegment revenues	4.6	–	.6	5.2	–	137.9
Interest income	–	–	–	–	3.9	3.9
Interest expense, net of capitalization	–	–	–	–	20.3	20.3
Income of equity companies	.5	–	–	.5	–	.5
Income tax expense (benefit)	.4	6.6	6.6	13.6	(14.9)	58.8
Significant noncash charges (credits)						
Depreciation, depletion, amortization	27.6	5.8	2.0	35.4	2.7	205.0
Provisions for major repairs	14.2	1.9	–	16.1	.1	18.7
Amortization of undeveloped leases	–	–	–	–	–	11.0
Deferred and noncurrent income taxes	7.9	(.5)	–	7.4	(.8)	38.0
Additions to property, plant, equipment	76.4	11.4	.3	88.1	2.6	327.0
Total assets at year-end	549.7	199.0	89.6	838.3	109.4	2,445.5

Geographic Information (Millions of dollars)	Revenues from External Customers for the Year U.S.	U.K.	Canada	Ecuador	Other	Total
2001	$3,142.1	573.1	727.7	33.4	2.2	4,478.5
2000	3,065.9	674.2	845.4	51.5	2.2	4,639.2
1999	1,798.4	459.8	457.2	39.0	2.0	2,756.4

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 and natural gas 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 discovered in Malaysia in 2001 are associated with a production sharing contract for Block SK 309. Reserves include oil to be received for both cost recovery and profit provisions under the contract.

Synthetic oil reserves in Canada 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.

The Company has no proved reserves attributable to either long-term supply agreements with foreign governments or investees accounted for by the equity method.

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 special items that are reviewed in Management's Discussion and Analysis of Financial Condition and Results of Operations on page 9 of this Form 10-K report, and should be considered in conjunction with the Company's overall performance.

SCHEDULE 6 – 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 2001 crude oil prices used for this calculation were $17.17 per barrel for the United States, $19.14 for Canadian light, $11.26 for Canadian heavy, $18.46 for Canadian offshore, $18.61 for the United Kingdom, $11.98 for Ecuador and $19.99 for Malaysia. Average year-end 2001 natural gas prices used were $2.40 per MCF for the United States, $2.30 for Canada and $3.12 for the United Kingdom.

Schedule 6 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, 2001.

Schedule 1 – Estimated Net Proved Oil Reserves

(Millions of barrels)	United States	Canada	United Kingdom	Ecuador	Malaysia	Total	Synthetic Oil – Canada	Total
	Crude Oil, Condensate and Natural Gas Liquids							
Proved								
December 31, 1998	23.0	50.8	56.7	32.2	–	162.7	115.6	278.3
Revisions of previous estimates	(1.6)	9.1	7.7	4.5	–	19.7	8.9	28.6
Extensions and discoveries	15.8	.7	–	2.9	–	19.4	–	19.4
Production	(3.1)	(6.9)	(7.5)	(2.6)	–	(20.1)	(4.0)	(24.1)
December 31, 1999	34.1	53.7	56.9	37.0	–	181.7	120.5	302.2
Revisions of previous estimates	(1.7)	4.5	1.8	3.6	–	8.2	7.6	15.8
Purchases	–	11.7	–	–	–	11.7	–	11.7
Extensions and discoveries	15.3	4.0	–	2.6	–	21.9	–	21.9
Production	(2.4)	(8.4)	(7.7)	(2.3)	–	(20.8)	(3.1)	(23.9)
Sales	–	(1.6)	–	–	–	(1.6)	–	(1.6)
December 31, 2000	45.3	63.9	51.0	40.9	–	201.1	125.0	326.1
Revisions of previous estimates	(.8)	2.8	.5	(.3)	–	2.2	9.8	12.0
Improved recovery	–	1.5	–	–	–	1.5	–	1.5
Purchases	–	.2	–	–	–	.2	–	.2
Extensions and discoveries	46.2	3.3	–	–	15.0	64.5	–	64.5
Production	(2.1)	(9.4)	(7.4)	(1.9)	–	(20.8)	(3.8)	(24.6)
Sales	–	(1.8)	–	–	–	(1.8)	–	(1.8)
December 31, 2001	88.6	60.5	44.1	38.7	15.0	246.9	131.0	377.9
Proved Developed								
December 31, 1998	14.5	27.9	31.5	21.0	–	94.9	67.1	162.0
December 31, 1999	11.7	26.6	34.1	21.2	–	93.6	66.0	159.6
December 31, 2000	10.3	34.3	36.3	20.1	–	101.0	66.0	167.0
December 31, 2001	8.8	37.9	33.3	21.3	–	101.3	66.0	167.3

Schedule 2 – Estimated Net Proved Natural Gas Reserves

(Billions of cubic feet)	United States	Canada	United Kingdom	Total
Proved				
December 31, 1998	440.1	130.1	39.1	609.3
Revisions of previous estimates	(2.6)	5.5	3.9	6.8
Extensions and discoveries	53.6	10.8	–	64.4
Production	(62.7)	(20.6)	(4.5)	(87.8)
Sales	(1.1)	–	–	(1.1)
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
Proved Developed				
December 31, 1998	291.8	120.3	29.9	442.0
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

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

(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Malaysia	Other	Subtotal	Synthetic Oil – Canada	Total
Year Ended December 31, 2001									
Property acquisition costs									
Unproved	$ 40.1	25.1	–	–	–	–	65.2	–	65.2
Proved	.3	21.3	–	–	–	–	21.6	–	21.6
Total acquisition costs	40.4	46.4	–	–	–	–	86.8	–	86.8
Exploration costs	86.5	105.9	.9	–	44.3	4.6	242.2	–	242.2
Development costs	132.1	167.4	17.9	9.0	.9	–	327.3	27.2	354.5
Total capital expenditures	259.0	319.7	18.8	9.0	45.2	4.6	656.3	27.2	683.5
Charged to expense									
Dry hole expense	23.7	47.0	.1	–	8.4	3.6	82.8	–	82.8
Geophysical and other costs	9.1	12.9	.8	–	27.2	1.0	51.0	–	51.0
Total charged to expense	32.8	59.9	.9	–	35.6	4.6	133.8	–	133.8
Expenditures capitalized	$ 226.2	259.8	17.9	9.0	9.6	–	522.5	27.2	549.7
Year Ended December 31, 2000									
Property acquisition costs									
Unproved	$ 19.2	25.1	–	–	–	–	44.3	–	44.3
Proved	1.5	2.9	–	–	–	–	4.4	–	4.4
Total	20.7	28.0	–	–	–	–	48.7	–	48.7
Exploration costs	96.2	32.1	5.2	.1	18.4	4.7	156.7	–	156.7
Development costs	20.3	113.8	22.5	12.2	–	–	168.8	18.5	187.3
Total capital expenditures	137.2	173.9	27.7	12.3	18.4	4.7	374.2	18.5	392.7
Beau Canada property acquisition									
Unproved	–	18.2	–	–	–	–	18.2	–	18.2
Proved	–	241.8	–	–	–	–	241.8	–	241.8
Total	–	260.0	–	–	–	–	260.0	–	260.0
Charged to expense									
Dry hole expense	56.7	5.7	1.7	–	1.3	.6	66.0	–	66.0
Geophysical and other costs	10.6	21.2	1.4	–	9.0	3.3	45.5	–	45.5
Total charged to expense	67.3	26.9	3.1	–	10.3	3.9	111.5	–	111.5
Expenditures capitalized	$ 69.9	407.0	24.6	12.3	8.1	.8	522.7	18.5	541.2
Year Ended December 31, 1999									
Property acquisition costs									
Unproved	$ 12.1	6.2	–	–	–	–	18.3	–	18.3
Proved	–	.4	–	–	–	–	.4	–	.4
Total acquisition costs	12.1	6.6	–	–	–	–	18.7	–	18.7
Exploration costs	54.9	14.2	1.2	1.0	2.6	5.3	79.2	–	79.2
Development costs	28.6	108.2	28.3	6.1	–	–	171.2	26.8	198.0
Total capital expenditures	95.6	129.0	29.5	7.1	2.6	5.3	269.1	26.8	295.9
Charged to expense									
Dry hole expense	24.2	3.9	3.0	–	–	1.3	32.4	–	32.4
Geophysical and other costs	10.7	8.9	.9	–	1.5	5.2	27.2	–	27.2
Total charged to expense	34.9	12.8	3.9	–	1.5	6.5	59.6	–	59.6
Expenditures capitalized	$ 60.7	116.2	25.6	7.1	1.1	(1.2)	209.5	26.8	236.3

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, 2001									
Revenues									
Crude oil and natural gas liquids									
Transfers to consolidated operations	$ 50.9	14.7	–	–	–	–	65.6	15.4	81.0
Sales to unaffiliated enterprises	1.0	152.5	181.5	33.4	–	–	368.4	80.4	448.8
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	244.7	349.8	193.6	33.4	–	–	821.5	95.8	917.3
Other operating revenues	(4.4)	2.1	.6	–	–	2.2	.5	–	.5
Total revenues	240.3	351.9	194.2	33.4	–	2.2	822.0	95.8	917.8
Costs and expenses									
Production expenses	48.4	72.0	30.8	14.9	–	–	166.1	51.9	218.0
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	40.3	90.7	37.2	6.4	.5	.3	175.4	8.3	183.7
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	151.8	250.3	71.3	21.9	36.1	10.5	541.9	60.3	602.2
	88.5	101.6	122.9	11.5	(36.1)	(8.3)	280.1	35.5	315.6
Income tax expense (benefit)[1]	30.7	39.1	44.3	–	–	(1.0)	113.1	12.5	125.6
Results of operations[2]	$ 57.8	62.5	78.6	11.5	(36.1)	(7.3)	167.0	23.0	190.0
Year Ended December 31, 2000									
Revenues									
Crude oil and natural gas liquids									
Transfers to consolidated operations	$ 68.6	68.4	11.6	–	–	–	148.6	37.9	186.5
Sales to unaffiliated enterprises	3.8	125.5	203.0	52.2	–	–	384.5	53.6	438.1
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	283.8	292.9	222.4	52.2	–	–	851.3	91.5	942.8
Other operating revenues	(4.8)	.5	.7	(.7)	–	2.2	(2.1)	–	(2.1)
Total revenues	279.0	293.4	223.1	51.5	–	2.2	849.2	91.5	940.7
Costs and expenses									
Production expenses	41.9	55.0	29.1	15.5	–	–	141.5	40.4	181.9
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	50.2	62.5	41.7	6.8	.4	.1	161.7	7.5	169.2
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	201.6	162.5	76.7	30.4	10.7	8.5	490.4	48.0	538.4
	77.4	130.9	146.4	21.1	(10.7)	(6.3)	358.8	43.5	402.3
Income tax expense	27.1	49.2	56.2	–	–	–	132.5	17.1	149.6
Results of operations[2]	$ 50.3	81.7	90.2	21.1	(10.7)	(6.3)	226.3	26.4	252.7

[1]Includes gains of $5.8 for a provincial tax rate reduction in Canada and $1.9 from settlement of U.K. income tax matters.
[2]Excludes corporate overhead and interest in 2001 and 2000 and cumulative effect of accounting change in 2000.

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, 1999									
Revenues									
Crude oil and natural gas liquids									
Transfers to consolidated operations	$ 48.8	15.9	23.4	–	–	–	88.1	42.8	130.9
Sales to unaffiliated enterprises	5.6	91.8	111.3	36.1	–	–	244.8	32.0	276.8
Natural gas									
Transfer to consolidated operations	1.8	–	–	–	–	–	1.8	–	1.8
Sales to unaffiliated enterprises	145.8	40.2	7.7	–	–	–	193.7	–	193.7
Total oil and gas revenues	202.0	147.9	142.4	36.1	–	–	528.4	74.8	603.2
Other operating revenues[1]	4.4	.2	–	2.9	–	2.0	9.5	–	9.5
Total revenues	206.4	148.1	142.4	39.0	–	2.0	537.9	74.8	612.7
Costs and expenses									
Production expenses	40.3	41.3	30.8	13.2	–	–	125.6	36.5	162.1
Exploration costs charged to expense	34.9	12.8	3.9	–	1.5	6.5	59.6	–	59.6
Undeveloped lease amortization	7.0	4.0	–	–	–	–	11.0	–	11.0
Depreciation, depletion and amortization	65.1	43.8	42.8	8.0	.1	–	159.8	7.1	166.9
Selling and general expenses	13.5	5.6	3.2	.1	–	1.1	23.5	–	23.5
Gain on disputed transportation	–	–	–	(4.9)	–	–	(4.9)	–	(4.9)
Total costs and expenses	160.8	107.5	80.7	16.4	1.6	7.6	374.6	43.6	418.2
	45.6	40.6	61.7	22.6	(1.6)	(5.6)	163.3	31.2	194.5
Income tax expense	10.3	14.3	24.5	–	–	.5	49.6	10.5	60.1
Results of operations[2]	$ 35.3	26.3	37.2	22.6	(1.6)	(6.1)	113.7	20.7	134.4

[1]Includes $3.3 from gain on disputed contractual item in Ecuador.
[2]Excludes corporate overhead and interest.

Schedule 5 – 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, 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*	(1,289.7)	(469.3)	(612.6)	(166.3)	–	–	(2,537.9)	(42.3)	(2,580.2)
Net capitalized costs	$ 489.7	954.2	182.3	61.6	15.5	–	1,703.3	161.7	1,865.0
December 31, 2000									
Unproved oil and gas properties	$ 109.9	76.2	.2	–	7.8	3.5	197.6	–	197.6
Proved oil and gas properties	1,493.6	1,213.5	805.2	219.0	–	–	3,731.3	188.5	3,919.8
Gross capitalized costs	1,603.5	1,289.7	805.4	219.0	7.8	3.5	3,928.9	188.5	4,117.4
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	(38.4)	(24.2)	(.1)	–	–	(3.5)	(66.2)	–	(66.2)
Proved oil and gas properties*	(1,244.0)	(409.8)	(601.4)	(160.0)	–	–	(2,415.2)	(37.0)	(2,452.2)
Net capitalized costs	$ 321.1	855.7	203.9	59.0	7.8	–	1,447.5	151.5	1,599.0

*Does not include reserve for dismantlement costs of $160.8 in 2001 and $160 in 2000.

Schedule 6 – Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

(Millions of dollars)	United States	Canada*	United Kingdom	Ecuador	Malaysia	Total
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
December 31, 1999						
Future cash inflows	$ 1,779.1	1,454.2	1,426.4	711.8	–	5,371.5
Future development costs	(210.6)	(90.1)	(66.0)	(48.1)	–	(414.8)
Future production and abandonment costs	(443.5)	(375.6)	(417.4)	(251.0)	–	(1,487.5)
Future income taxes	(356.4)	(202.8)	(315.9)	(115.9)	–	(991.0)
Future net cash flows	768.6	785.7	627.1	296.8	–	2,478.2
10% annual discount for estimated timing of cash flows	(271.3)	(230.6)	(205.5)	(119.8)	–	(827.2)
Standardized measure of discounted future net cash flows	$ 497.3	555.1	421.6	177.0	–	1,651.0

*Excludes future net cash flows from synthetic oil of $188 at December 31, 2001, $441.5 at December 31, 2000 and $410.2 at December 31,1999.

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

(Millions of dollars)	2001	2000	1999
Net changes in prices, production costs and development costs	$(3,024.6)	722.0	1,188.2
Sales and transfers of oil and gas produced, net of production costs	(267.7)	(485.1)	(317.9)
Net change due to extensions and discoveries	691.6	544.4	250.0
Net change due to purchases and sales of proved reserves	19.3	519.2	(2.0)
Development costs incurred	308.7	156.6	163.4
Accretion of discount	390.6	229.3	71.9
Revisions of previous quantity estimates	1.4	(73.7)	220.7
Net change in income taxes	703.3	(659.9)	(505.2)
Net increase (decrease)	(1,177.4)	952.8	1,069.1
Standardized measure at January 1	2,603.8	1,651.0	581.9
Standardized measure at December 31	$ 1,426.4	2,603.8	1,651.0

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, 2001[1]					
Sales and other operating revenues	$ 1,185.7	1,297.0	1,136.4	847.7	4,466.8
Income before income taxes	156.0	247.0	69.6	33.3	505.9
Net income	97.8	162.6	41.7	28.8	330.9
Net income per Common share – basic	2.17	3.60	.92	.63	7.32
Net income per Common share – diluted	2.16	3.56	.91	.63	7.26
Cash dividends per Common share	.375	.375	.375	.375	1.50
Market Price of Common Stock[2]					
High	69.00	87.85	85.70	84.98	87.85
Low	55.25	67.14	66.55	68.00	55.25
Year Ended December 31, 2000[1]					
Sales and other operating revenues	$ 1,019.3	1,092.4	1,232.2	1,270.4	4,614.3
Income before income taxes and cumulative effect of accounting change	74.0	119.9	133.0	138.4	465.3
Income before cumulative effect of accounting change	49.1	73.1	90.1	93.2	305.5
Cumulative effect of accounting change	(8.7)	–	–	–	(8.7)
Net income	40.4	73.1	90.1	93.2	296.8
Income per Common share – basic					
Income before cumulative effect of accounting change	1.09	1.62	2.00	2.07	6.78
Cumulative effect of accounting change	(.19)	–	–	–	(.19)
Net income	.90	1.62	2.00	2.07	6.59
Income per Common share – diluted					
Income before cumulative effect of accounting change	1.09	1.61	1.99	2.06	6.75
Cumulative effect of accounting change	(.19)	–	–	–	(.19)
Net income	.90	1.61	1.99	2.06	6.56
Cash dividends per Common share	.35	.35	.375	.375	1.45
Market Price of Common Stock[2]					
High	63.4375	66.5000	69.0625	68.8750	69.0625
Low	48.1875	54.7500	56.0000	53.3750	48.1875

[1]The effect of special gains (losses) on quarterly net income are reviewed in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 12 and 13 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
2001					
Quarterly totals	$ –	67.6	–	–	67.6
Per Common share – basic	–	1.50	–	–	1.50
Per Common share – diluted	–	1.48	–	–	1.48
2000					
Quarterly totals	$ –	1.5	1.9	(1.9)	1.5
Per Common share – basic	–	.03	.04	(.04)	.03
Per Common share – diluted	–	.03	.04	(.04)	.03

[2]Prices are as quoted on the New York Stock Exchange.

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

(Millions of dollars)	Balance at January 1	Additions: Charged (Credited) to Expense	Additions: Other*	Deductions	Balance at December 31
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	(.3)	(10.5)	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	(.5)	(10.1)	34.3
1999					
Deducted from asset accounts:					
Allowance for doubtful accounts	11.0	(2.5)	–	(.2)	8.3
Allowance for inventory valuation	6.8	–	–	(6.8)	–
Deferred tax asset valuation allowance	47.3	10.1	–	–	57.4
Included in liabilities:					
Accrued major repair costs	43.5	18.7	.2	(40.3)	22.1

*Amounts represent changes in foreign currency exchange rates.

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CORPORATE INFORMATION

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Stock Exchange Listings
Trading Symbol: MUR
New York Stock Exchange
Toronto Stock Exchange

Transfer Agents
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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 8, 2002 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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MURPHY
OIL CORPORATION

The 2001 Annual Report

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Principal Offices

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New Orleans, Louisiana
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