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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 [FEE REQUIRED]

For the fiscal year ended DECEMBER 31, 1995

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]

For the transition period from _______________ to _______________

Commission file number 1-8590

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

Delaware	71-0361522
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

200 Peach Street, P. O. Box 7000, El Dorado, Arkansas	71731-7000
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (501) 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 The Toronto Stock Exchange
Series A Participating Cumulative Preferred Stock Purchase Rights	New York Stock Exchange The 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 X 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 February 29, 1996 as quoted by the New York Stock Exchange, was approximately $1,398,815,000.

Number of shares of Common Stock, $1.00 Par Value, outstanding at February 29, 1996, was 44,851,962.

Documents incorporated by reference:

The Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 8, 1996 (Part III)

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TABLE OF CONTENTS - 1995 FORM 10-K REPORT

PART I

ITEMS 1. AND 2. BUSINESS AND PROPERTIES.

Murphy Oil Corporation is a natural resources company that operates through subsidiaries in the United States and internationally to conduct the various business activities of the enterprise. As used in this report, the terms Murphy, we, our, its, and Company may refer to any one or more of the consolidated subsidiaries as well as to Murphy Oil Corporation.

The Company was originally incorporated in Louisiana in 1950 as Murphy Corporation; reincorporated in Delaware in 1964, at which time it adopted the name Murphy Oil Corporation; and reorganized in 1983 to operate solely as a holding company of its various businesses. Its activities are classified into two business segments: (1) "Petroleum," which comprises its international integrated oil and gas operations and is further subdivided into "Exploration and Production" and "Refining, Marketing, and Transportation," and (2) "Farm, Timber, and Real Estate," which has operations primarily in Arkansas and North Louisiana. Additionally, "Corporate and Other" activities include interest income, interest expense, and overhead not allocated to either of the business segments.

The information appearing on pages 4 through 50 of the 1995 Annual Report to Security Holders (1995 Annual Report) is incorporated in this Annual Report on Form 10-K as Exhibit 13 and is deemed to be filed as part of this 10-K report as indicated under Items 1, 2, 3, 5, 6, 7, 8, and 14. A narrative of the graphic and image information that appears in the paper format version of Exhibit 13 on pages 4 through 50 is included in the electronic Form 10-K document as an appendix to Exhibit 13 (pages A-1 through A-8).

In addition to the following information about each business segment, data relative to Murphy's operations, properties, and industry segments, including revenues by class of products and financial information by geographic areas, are described on pages 20 through 28, 40, 41, 46, and 47 of the 1995 Annual Report, which is filed in this 10-K report as Exhibit 13.

PETROLEUM - EXPLORATION AND PRODUCTION

During 1995, Murphy's principal exploration and/or production activities were conducted in the United States, Ecuador, Spain, China, Pakistan, Peru, the Falkland Islands, and Ireland by wholly owned Murphy Exploration & Production Company (Murphy Expro) and its subsidiaries; in Canada by wholly owned Murphy Oil Company Ltd. (MOCL) and its subsidiaries; and in the U.K. North Sea by wholly owned Murphy Petroleum Limited. Murphy's crude oil and natural gas liquids production is primarily in the United States, Canada, the U.K. North Sea, and Ecuador; its natural gas is produced and sold in the United States, Canada, the United Kingdom, and Spain. MOCL also has a five-percent interest in Syncrude Canada Ltd., which extracts synthetic crude oil from oil sand deposits in northern Alberta.

Murphy's estimated net quantities of proved oil and gas reserves and proved developed oil and gas reserves at January 1, 1993 and at December 31, 1993, 1994, and 1995 by geographic area are reported on pages 43 and 44 of the 1995 Annual Report, which is filed in this 10-K report as Exhibit 13. Murphy has not filed, and is not required to file, any estimates of its total proved net oil or gas reserves on a recurring basis with any federal or foreign governmental regulatory authority or agency other than the SEC. 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 total net proved reserves of such properties are determined.

In 1995, essentially all of Murphy's crude oil, condensate, and natural gas liquids production in the United States was delivered, either directly or indirectly through exchanges, to its own refineries. Net crude oil, condensate, and gas liquids production and net natural gas sales by geographic area with weighted average sales prices for each of the five years ended December 31, 1995 appear on page 48 of the 1995 Annual Report, which is filed in this 10-K report as Exhibit 13.

Production costs in U.S. dollars per equivalent barrel produced, including natural gas volumes converted to equivalent barrels of crude oil on the basis of approximate relative energy content, are shown on page 23 of the 1995 Annual Report, which is filed in this 10-K report as Exhibit 13.

PETROLEUM - EXPLORATION AND PRODUCTION (Contd.)

Supplemental disclosures about oil and gas producing activities are reported on pages 42 through 47 of the 1995 Annual Report, which is filed in this 10-K report as Exhibit 13.

At December 31, 1995, Murphy held leases, concessions, contracts, or permits on nonproducing and producing acreage in the following countries (thousands of acres).

	Nonproducing	Producing	Total

Country	Gross	Net	Gross	Net	Gross	Net
United States - Onshore	20	11	186	58	206	69
- Gulf of Mexico	614	360	415	152	1,029	512
- Frontier	127	89	-	-	127	89
Total United States	761	460	601	210	1,362	670
Canada - Onshore	756	378	517	196	1,273	574
- Offshore	138	17	-	-	138	17
- Oil sands	157	41	14	5	171	46
Total Canada	1,051	436	531	201	1,582	637
United Kingdom	715	164	81	13	796	177
Ecuador	-	-	494	99	494	99
Spain	28	5	61	11	89	16
China	563	254	-	-	563	254
Ireland	650	162	-	-	650	162
Pakistan	11,100	8,472	-	-	11,100	8,472
Peru	3,112	3,112	-	-	3,112	3,112
Tunisia	165	42	-	-	165	42
Totals	18,145	13,107	1,768	534	19,913	13,641

Oil and gas wells producing or capable of producing at December 31, 1995 are summarized as follows.

	Oil Wells		Gas Wells	
Country	Gross	Net	Gross	Net
United States	1,278	528.4	408	141.6
Canada	4,084	734.0	765	231.0
United Kingdom	79	10.7	20	1.5
Ecuador	26	5.2	-	-
Spain	-	-	1	.2
Totals	5,467	1,278.3	1,194	374.3
Wells included above with multiple completions and counted as one well each	119	51.9	112	65.5

Gross wells are those in which all or part of the working interest is owned by Murphy. Net wells are the portions of the gross wells applicable to Murphy's working interest.

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

	United States		Canada		United Kingdom		Ecuador		Other		Totals	
	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry
1995												
Exploratory	4.6	1.9	6.0	4.3	.3	.1	-	-	-	.5	10.9	6.8
Development	2.0	-	25.9	1.6	.8	-	2.8	-	-	-	31.5	1.6
1994												

Exploratory	6.1	4.0	5.4	5.0	.5	.5	-	-	-	-	12.0	9.5
Development	.5	.1	29.8	1.5	.6	-	2.0	-	-	-	32.9	1.6
1993												
Exploratory	7.4	6.5	3.9	4.2	.1	-	-	-	-	.5	11.4	11.2
Development	4.1	-	24.5	2.7	.7	.1	1.2	-	-	-	30.5	2.8

The wells being drilled by Murphy at December 31, 1995 are summarized as follows.

	Exploratory		Development		Totals	
Country	Gross	Net	Gross	Net	Gross	Net
United States	11	5.1	-	-	11	5.1
Canada	-	-	1	.2	1	.2
United Kingdom	1	.3	3	.3	4	.6
Ecuador	-	-	1	.2	1	.2
Totals	12	5.4	5	.7	17	6.1

Additional information about current exploration and production activities is reported on pages 4 through 12 of the 1995 Annual Report, which is filed in this 10-K report as Exhibit 13.

PETROLEUM - REFINING, MARKETING, AND TRANSPORTATION

Murphy Oil USA, Inc. (Murphy USA), a wholly owned subsidiary, owns and operates two refineries in the United States. The refinery at Superior, Wisconsin, is located on fee land. The Meraux, Louisiana, refinery is located on both fee and leased land; these leases expire at varying times from 2010 to 2022, and at such times the Company has options to purchase all leased acreage at fixed prices. Murco Petroleum Limited (Murco), a wholly owned U.K. subsidiary serviced by Murphy Eastern Oil Company, has an effective 30-percent interest in a 108,000-barrel-a-day refinery at Milford Haven, Wales. Refinery capacities at December 31, 1995 are shown in the following table.

	Meraux, Louisiana	Superior, Wisconsin	Milford Haven, Wales (Murco's 30%)	Totals
Crude capacity - b/sd*	100,000	35,000	32,400	167,400
Process capacities - b/sd*				
Vacuum distillation	50,000	20,000	16,500	86,500
Catalytic cracking - fresh feed	40,000	11,000	9,960	60,960
Pretreating cat-reforming feeds	26,000	9,000	5,490	40,490
Catalytic reforming	18,500	8,000	5,490	31,990
Distillate hydrotreating	15,000	5,800	9,000	29,800
Gas oil hydrotreating	33,000	-	-	33,000
Solvent deasphalting	18,000	-	-	18,000
Isomerization	-	2,000	2,250	4,250
Production capacities - b/sd*				
Alkylation	9,500	1,600	1,680	12,780
Asphalt	-	13,500	-	13,500

Crude oil and product storage capacities - bbls.	4,453,000	2,852,000	2,638,000	9,943,000

*Barrels per stream day.

Murphy distributes refined products from 47 terminals in the United States to retail and wholesale accounts in the United States (Murphy USA) and Canada (MOCL) under the brand name SPUR and to unbranded wholesale accounts. Four of these are marine terminals, two are supplied by truck, two are adjacent to the refineries, and 39 are supplied by pipeline. Nine terminals are wholly owned and operated by Murphy USA, 16 are jointly owned and operated by others, and the remaining 22 are owned by others. Murphy USA receives products at the terminals owned by others in exchange for deliveries from the Company's wholly owned and jointly owned terminals. At the end of 1995, refined products were marketed at wholesale and/or retail through 514 branded outlets in 15 southeastern and upper midwestern states and seven branded outlets in the Thunder Bay area of Ontario, Canada.

At the end of 1995, Murco distributed refined products in the United Kingdom from the Milford Haven refinery; three wholly owned, rail-fed terminals; eight terminals owned by others where products are received in exchange for deliveries from the Company's wholly owned terminals; and 465 branded outlets under the brand names MURCO and EP.

Murphy owns a 20-percent interest in a 120-mile, 165,000-barrel-a-day refined products pipeline that transports products from the Meraux refinery to two common carrier pipelines serving Murphy's marketing area in the southeastern United States. The Company also owns a 22-percent interest in a 312-mile crude oil pipeline in Montana and Wyoming with a capacity of 120,000 barrels a day and a 3.2-percent interest in LOOP Inc., which provides deep-water off-loading accommodations off the Louisiana coast for oil tankers and onshore facilities for storage of crude oil. In addition, Murphy owns 29.4 percent of a 22-mile, 300,000-barrel-a-day crude oil pipeline between LOOP storage at Clovelly, Louisiana, and Alliance, Louisiana, and 100 percent of a 24-mile, 200,000-barrel-a-day crude oil pipeline from Alliance to the Meraux refinery. The pipeline from Alliance to Meraux is also connected to another company's pipeline system, allowing crude oil from wells serviced by that system to be shipped to the refinery.

As of December 31, 1995, MOCL had a 52.5-percent interest in a 114-mile dual pipeline in Canada that transports heavy crude oil from Blackfoot, Alberta, to Kerrobert, Saskatchewan, where access to a major crude oil trunk line is available. In connection with this pipeline, which has a throughput capacity of 50,000 barrels a day, MOCL owns interests in two dual crude oil pipelines--100 percent of a two-mile, 2,500-barrel-a-day lateral line at Winter, Saskatchewan, and 52.5 percent of a 4.5-mile, 5,000-barrel-a-day lateral line at Neilburg, Saskatchewan. MOCL also owns 13.1 percent of a 40-mile, 38,000-barrel-a-day dual heavy crude oil pipeline from Cactus Lake, Saskatchewan, to Kerrobert; 41 percent of a 15-mile, 9,000-barrel-a-day dual crude oil pipeline from Bodo, Alberta, to Cactus Lake; 100 percent of a 10.5-mile, 82,500-barrel-a-day dual crude oil pipeline from

Milk River, Alberta, to the U.S. border; 100 percent of a 108-mile, 45,000-barrel-a-day crude oil pipeline from Regina, Saskatchewan, to the U.S. border; and 100 percent of a 28-mile, 15,000-barrel-a-day heavy crude oil pipeline from Eyehill, Saskatchewan, to Unity, Saskatchewan. MOCL is operator of these pipelines.

Additional information about current refining, marketing, and transportation activities and a statistical summary of key operating and financial indicators for each of the five years ended December 31, 1995 are reported on pages 13 through 17 and 49 of the 1995 Annual Report, which is filed in this 10-K report as Exhibit 13.

FARM, TIMBER, AND REAL ESTATE

Deltic Farm & Timber Co. Inc. (Deltic), a wholly owned subsidiary, is engaged in farming and timber and land management in Arkansas and North Louisiana, lumber manufacturing and marketing in Arkansas, and real estate development in Little Rock, Arkansas.

Deltic owns sawmills at Ola in central Arkansas and at Waldo in southern Arkansas. The mills have a combined annual capacity to produce 165 million board feet of lumber. The Ola mill is equipped for maximum utilization of small stem timber, while the Waldo mill can process both small and large diameter timber.

Deltic owned 341,000 acres of timberland at year-end 1995. Its estimated standing timber inventories on this acreage are calculated for each tract by utilizing growth formulas based on representative sample tracts and tree counts for various diameter classifications. The calculations of pine inventories are subject to periodic adjustments based on sample cruises or actual volumes harvested from related tracts. The hardwood inventories shown in the following table are only approximations, so physical quantities of such timber may vary significantly from these approximations. Estimated inventories of standing timber at year-end for each of the last three years were as follows.

	1995	1994	1993
Pine sawtimber - MBF*	765,000	812,000	810,000
Hardwood sawtimber - MBF*	97,000	105,000	113,000
Pine pulpwood - cords	1,180,000	991,000	963,000
Hardwood pulpwood - cords	360,000	396,000	417,000

*Thousand board feet - Doyle scale.

At Deltic's farms, which comprise 36,000 acres in northeastern Louisiana and southeastern Arkansas, the primary crops grown and harvested are cotton, soybeans, corn, wheat, and rice. In western Little Rock, Arkansas, Deltic has been developing Chenal Valley, a 4,300-acre planned community centered around one of Arkansas's top-ranked golf courses, in stages over recent years and has been selling real estate, primarily residential lots thus far, in Chenal Valley.

Additional information about current farm, timber, and real estate activities and a statistical summary of key operating and financial indicators for each of the five years ended December 31, 1995 are reported on pages 18, 19, and 50 of the 1995 Annual Report, which is filed in this 10-K report as Exhibit 13.

EMPLOYEES

Murphy had 1,794 full-time employees at December 31, 1995.

COMPETITION AND OTHER CONDITIONS WHICH MAY AFFECT BUSINESS

Murphy operates principally in the oil industry, in which it 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 occasionally purchases refined products and may therefore 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" on page 27 of the 1995 Annual Report, which is filed in this 10-K report as Exhibit 13.

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 fixing prices and determining rates of production and who may sell and buy the production. Until 1993, the United States also regulated prices for certain natural gas 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/or remediation of the environment (See the caption "Environmental" on page 26 of the 1995 Annual Report, which is filed in this 10-K report as Exhibit 13.), preferential and discriminatory awarding of oil and gas leases, restraints and controls on imports and exports, safety, and relationships between employers and employees. Because these and other government-influenced factors too numerous to list are subject to constant changes dictated by 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 policy is to insure against known risks when insurance is available at costs and terms Murphy considers reasonable. Certain existing risks are insured by Murphy only through Oil Insurance Limited (OIL), which is operated as a mutual insurance company by certain participating oil companies including Murphy and was organized to insure against risks for which commercial insurance is unavailable or for which the cost of commercial insurance is prohibitive.

EXECUTIVE OFFICERS OF THE REGISTRANT

The age (at January 1, 1996), present corporate office, and length of service in office of each of the Company's executive officers and persons chosen to become 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 38; Chairman of the Board since October 1994. Mr. Murphy had been Executive Vice President and Chief Financial and Administrative Officer, Director, and Member of the Executive Committee since 1993. Prior to that, he was 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 41; President and Chief Executive Officer since October 1994 and Director and Member of the Executive Committee since 1993. In 1992, he became Executive Vice President and Chief Operating Officer. Mr. Deming was President of Murphy USA from 1989 to 1992 and Vice President, Petroleum Operations, for Murphy from 1988 to 1989.

Steven A. Cosse - Age 48; Senior Vice President since October 1994 and General Counsel since August 1991. Mr. Cosse was elected Vice President in 1993. For the eight years prior to August 1991, he was General Counsel for Murphy Expro, at that time named Ocean Drilling & Exploration Company (ODECO), a majority-owned subsidiary of Murphy.

Herbert A. Fox Jr. - Age 61; Vice President since October 1994. Mr. Fox has also been President of Murphy USA since 1992. He served with Murphy USA as Vice President, Manufacturing, from 1990 to 1992 and as Manager of Crude Supply from 1973 to 1990.

Bill H. Stobaugh - Age 44; 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.

Clefton D. Vaughan - Age 54; Vice President since October 1994. He has also been Vice President of Murphy Expro since 1992. Mr. Vaughan was Vice President of Murphy from 1989 to 1992 and held various other positions with the Company prior to that.

Odie F. Vaughan - Age 59; Treasurer since August 1991. From 1975 through July 1991, he was with ODECO as Vice President of Taxes and Treasurer.

Ronald W. Herman - Age 58; Controller since August 1991. He was Controller of ODECO from 1977 through July 1991.

W. Bayless Rowe - Age 43; Secretary since 1988 and Manager of Law Department since October 1994. He was General Attorney from 1988 to October 1994.

ITEM 3. LEGAL PROCEEDINGS.

Information related to legal proceedings contained in Note P, page 40 of the 1995 Annual Report, which is filed in this 10-K report as Exhibit 13, is incorporated herein. Also, Murphy Oil USA, Inc., in connection with its ownership and operation of two oil refineries in the United States, is a defendant in two governmental actions that: (1) seek monetary sanctions of $100,000 or more, and (2) arise under enacted provisions that regulate the discharge of materials into the environment or have the purpose of protecting the environment. These actions individually or in the aggregate are not material to the financial condition of the Company. In addition, 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 material as defined by the rules and regulations of the U.S. Securities and Exchange Commission.

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 1995.

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. Other information required by this item is reported on page 28 of the 1995 Annual Report, which is filed in this 10-K report as Exhibit 13.

ITEM 6. SELECTED FINANCIAL DATA.

Information required by this item appears on page 20 of the 1995 Annual Report, which is filed in this 10-K report as Exhibit 13.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION.

Information required by this item appears on pages 21 through 28 of the 1995 Annual Report, which is filed in this 10-K report as Exhibit 13.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Information required by this item appears on pages 28 through 47 of the 1995 Annual Report, which is filed in this 10-K report as Exhibit 13.

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 in Part I, pages 8 and 9, of this 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, 1996, 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, 1996, under the captions "Compensation of Directors," "Executive Compensation," "Option Exercises and Fiscal Year-End Values," "Option Grants," "Compensation Committee Report for 1995," "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, 1996, under the caption "Certain Stock Ownerships."

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

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, 1996, under the caption "Compensation Committee Interlocks and Insider Participation."

PART IV

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

(a) 1. FINANCIAL STATEMENTS

The following consolidated financial statements of Murphy Oil Corporation and consolidated subsidiaries are included on the pages indicated of Exhibit 13 to this 10-K report.

	Exhibit 13 Page Nos.
Independent Auditors' Report	29
Consolidated Statements of Income	30
Consolidated Balance Sheets	31
Consolidated Statements of Cash Flows	32
Consolidated Statements of Stockholders' Equity	33
Notes to Consolidated Financial Statements	34 through 41

(a) 2. FINANCIAL STATEMENT SCHEDULES

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.

(a) 3. EXHIBITS

The Exhibit Index on page 13 of this 10-K report lists the exhibits that are hereby filed.

(b) REPORTS ON FORM 8-K

No reports on Form 8-K were filed during the quarter ended December 31, 1995.

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 Date: March 26, 1996

Claiborne P. Deming, President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on March 26, 1996 by the following persons on behalf of the registrant and in the capacities indicated.

R. MADISON MURPHY	MICHAEL W. MURPHY
R. Madison Murphy, Chairman and Director	Michael W. Murphy, Director
CLAIBORNE P. DEMING	WILLIAM C. NOLAN JR.
Claiborne P. Deming, President and Chief Executive Officer and Director (Principal Executive Officer)	William C. Nolan Jr., Director
B. R. R. BUTLER	CAROLINE G. THEUS
B. R. R. Butler, Director	Caroline G. Theus, Director
GEORGE S. DEMBROSKI	LORNE C. WEBSTER
George S. Dembroski, Director	Lorne C. Webster, Director
H. RODES HART	STEVEN A. COSSE
H. Rodes Hart, Director	Steven A. Cosse, Senior Vice President and General Counsel (Principal Financial Officer)
VESTER T. HUGHES JR.	RONALD W. HERMAN
Vester T. Hughes Jr., Director	Ronald W. Herman, Controller (Principal Accounting Officer)
C. H. MURPHY JR.	
C. H. Murphy Jr., Director	

EXHIBIT INDEX

Exhibit No.		Page Number or Incorporation by Reference to
3.1	Certificate of Incorporation of Murphy Oil Corporation as of September 25, 1986	Exhibit 3.1, Page Ex. 3.1-0, of Murphy's Annual Report on Form 10-K for the year ended December 31, 1991
3.2	Bylaws of Murphy Oil Corporation at February 1, 1995	Exhibit 3.3, Page Ex. 3.3-1, of Murphy's Annual Report on Form 10-K for the year ended December 31, 1994

3.3	Bylaws of Murphy Oil Corporation at October 4, 1995	Page Ex. 3.3-1
4	Instruments Defining the Rights of Security Holders. Murphy Oil Corporation is party to several long-term debt instruments, none of which authorizes securities that exceed 10 percent of the total assets of Murphy Oil Corporation and its subsidiaries on a consolidated basis. 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	Rights Agreement dated as of December 6, 1989 between Murphy Oil Corporation and Harris Trust Company of New York, as Rights Agent	Exhibit 4.1, Page Ex. 4.1-0, of Murphy's Annual Report on Form 10-K for the year ended December 31, 1994
10.1	1982 Management Incentive Plan	Exhibit 10.2, Page Ex. 10.2-0, of Murphy's Annual Report on Form 10-K for the year ended December 31, 1991
10.2	1987 Management Incentive Plan (adopted May 13, 1987, amended February 7, 1990 retroactive to February 3, 1988)	Exhibit 10.2, Page Ex. 10.2-0, of Murphy's Annual Report on Form 10-K for the year ended December 31, 1994
10.3	1992 Stock Incentive Plan	Exhibit 10.3, Page Ex. 10.3-0, of Murphy's Annual Report on Form 10-K for the year ended December 31, 1992
13	1995 Annual Report to Security Holders Appendix - Narrative to Graphic and Image Material	Page Ex. 13-0, report pp. 4 through 50 (Page A-1 for electronic filing only)
21	Subsidiaries of the Registrant	Page Ex. 21-1
23	Independent Auditors' Consent	Page Ex. 23-1
27.1	Financial Data Schedule for 1995	(Electronic filing only)
27.2	Restated Financial Data Schedule for 1994	(Electronic filing only)
99.1	Undertakings	Page Ex. 99.1-1
99.2	Form 11-K, Annual Report for the fiscal year ended December 31, 1995 covering Combined Thrift Plans for Employees of Murphy Oil Corporation, Murphy Oil USA, Inc., and Deltic Farm & Timber Co., Inc.	To be filed as an amendent of this Annual Report on Form 10-K not later than 180 days after December 31, 1995

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

EXHIBIT 3.3

BYLAWS (AS AMENDED OCTOBER 4, 1995)

OF

MURPHY OIL CORPORATION

(A Delaware corporation)

ARTICLE I.

Offices.

Section 1. Offices. Murphy Oil Corporation (hereinafter called the Company) may have, in addition to its principal office in Delaware, a principal or other office or offices at such place or places, either within or without the State of Delaware, as the board of directors may from time to time determine or as shall be necessary or appropriate for the conduct of the business of the Company.

ARTICLE II.

Meetings of Stockholders.

Section 1. Place of Meetings. The annual meeting of the stockholders shall be held at the place therein determined by the board of directors and stated in the notice thereof, and other meetings of the stockholders may be held at such place or places, within or without the State of Delaware, as shall be fixed by the board of directors and stated in the notice thereof.

Section 2. Annual Meetings. The annual meeting of stockholders for the election of directors and the transaction of such other business as may come before the meeting shall be held in each year on the second Wednesday in May. If this date shall fall upon a legal holiday, the meeting shall be held on the next succeeding business day. At each annual meeting the stockholders entitled to vote shall elect a board of directors and they may transact such other corporate business as shall be stated in the notice of the meeting.

Section 3. Special Meetings. Special meetings of the stockholders for any purpose or purposes may be called by the Chairman of the Board or by order of the board of directors and shall be called by the Chairman of the Board or the Secretary upon the written request of stockholders holding of record at least a majority of the outstanding shares of stock of the Company entitled to vote at such meeting. Such written request shall state the purpose or purposes for which such meeting is to be called.

Section 4. Notice of Meetings. Except as otherwise expressly required by law, notice of each meeting of stockholders, whether annual or special, shall be given at least 10 days before the date on which the meeting is to be held to each stockholder of record entitled to

vote thereat by delivering a notice thereof to him personally, or by mailing such notice in a postage prepaid envelope directed to him at his address as it appears on the books of the Company, unless he shall have filed with the Secretary of the Company a written request that notices intended for him be directed to another address, in which case such notice shall be directed to him at the address designated in such request. Notice of any meeting of stockholders shall not be required to be given to any stockholder who shall attend such meeting in person or by proxy; and if any stockholder shall in person or by attorney thereunto authorized, in writing or by telegraph, cable, radio or wireless and confirmed in writing, waive notice of any meeting of the stockholders, whether prior to or after such meeting, notice thereof need not be given to him. Notice of any adjourned meeting of the stockholders shall not be required to be given except where expressly required by law.

Section 5. Quorum. At each meeting of the stockholders the holders of record of a majority of the issued and outstanding stock of the Company entitled to vote at such meeting, present in person or by proxy, shall constitute a quorum for the transaction of business except where otherwise provided by law, the certificate of incorporation or these bylaws. In the absence of a quorum, any officer entitled to preside at or act as secretary of such meeting shall have the power to adjourn the meeting from time to time until a quorum shall be constituted. At any such adjourned meeting at which a quorum shall be present any business may be transacted which might have been transacted at the meeting as originally called.

Section 6. Voting. At every meeting of stockholders each holder of record of the issued and outstanding stock of the Company entitled to vote at such meeting shall be entitled to one vote in person or by proxy, but no proxy shall be voted after three years from its date unless the proxy provides for a longer period, and, except where the transfer books of the Company have been closed or a date has been fixed as the record date for the determination of stockholders entitled to vote, no share of stock shall be voted directly or indirectly. At all meetings of the stockholders, a quorum being present, all matters shall be decided by majority vote of those present in person or by proxy, except as otherwise required by the laws of the State of Delaware or the certificate of incorporation. The vote thereat on any question need not be by ballot unless required by the laws of the State of Delaware.

ARTICLE III.

Board of Directors.

Section 1. General Powers. The property, business and affairs of the Company shall be managed by the board of directors.

Section 2. Number and Term of Office. The number of directors shall be eleven, but may from time to time be increased or diminished to not less than three by amendment of these bylaws. Directors need not be stockholders. Each director shall hold office until the annual meeting of the stockholders next following his election and until his successor shall have been elected and shall qualify, or until his death, resignation or removal.

Section 3. Quorum and Manner of Acting. Unless otherwise provided by law the presence of six members of the board of directors shall be necessary to constitute a quorum

for the transaction of business. In the absence of a quorum, a majority of the directors present may adjourn the meeting from time to time until a quorum shall be present. Notice of any adjourned meeting need not be given. At all meetings of directors, a quorum being present, all matters shall be decided by the affirmative vote of a majority of the directors present, except as otherwise required by the laws of the State of Delaware.

Section 4. Place of Meetings, etc. The board of directors may hold its meetings and keep the books and records of the Company at such place or places within or without the State of Delaware as the board may from time to time determine.

Section 5. Annual Meeting. Promptly after each annual meeting of stockholders for the election of directors and on the same day the board of directors shall meet for the purpose of organization, the election of officers and the transaction of other business. Notice of such meeting need not be given. Such meeting may be held at any other time or place as shall be specified in a notice given as hereinafter provided for special meetings of the board of directors or in a consent and waiver of notice thereof signed by all the directors.

Section 6. Regular Meetings. Regular meetings of the board of directors may be held at such time and place, within or without the State of Delaware, as shall from time to time be determined by the board of directors. After there has been such determination and notice thereof has been once given to each member of the board of directors, regular meetings may be held without further notice being given.

Section 7. Special Meetings; Notice. Special meetings of the board of directors shall be held whenever called by the Chairman of the Board or by a majority of the directors. Notice of each such meeting shall be mailed to each director, addressed to him at his residence or usual place of business, at least 10 days before the day on which the meeting is to be held, or shall be sent to him at such place by telegraph, cable, radio or wireless, or be delivered personally or by telephone, not later than the day before the day on which such meeting is to be held. Each such notice shall state the time and place of the meeting but need not state the purposes thereof. Notice of any meeting of the board of directors need not be given to any director, however, if waived by him in writing or by telegraph, cable, radio or wireless and confirmed in writing, whether before or after such meeting, or if he shall be present at such meeting. Any meeting of the board of directors shall be a legal meeting without any notice thereof having been given if all the directors then in office shall be present thereat.

Section 8. Resignation. Any director of the Company may resign at any time by giving written notice to the Chairman of the Board or the Secretary of the Company. The resignation of any director shall take effect upon receipt of notice thereof or at such later time as shall be specified in such notice; and, unless otherwise specified therein, the acceptance of such resignation shall not be necessary to make it effective.

Section 9. Removal. Any director may be removed at any time, either with or without cause, by the affirmative vote of the holders of record of a majority of the issued and outstanding class of stock of the Company entitled to vote for the election of such director, given at a special meeting of the stockholders called for that purpose. The vacancy in the board of directors caused by any such removal may be filled by the stockholders at such meeting.

Section 10. Vacancies. Any vacancy that shall occur in the board of directors by reason of death, resignation, disqualification or removal or any other cause whatever, unless filled as provided in Section 9 hereof, shall be filled by the majority (even if that be only a single director) of the remaining directors theretofore elected by the holders of the class of capital stock which elected the directors whose office shall have become vacant. If any new directorship is created by increase in the number of directors, a majority of the directors then in office may fill such new directorship. The term of office of any director so chosen to fill a vacancy or a new directorship shall terminate upon the election and qualification of directors at any meeting of stockholders called for the purpose of electing directors.

Section 11. Compensation of Directors. Directors may receive a fee, as fixed by the Chairman of the Board, for their services, together with expenses for attendance at regular or special meeting of the board. Members of committees of the board of directors may be allowed compensation for attending committee meetings. Nothing herein contained shall be construed to preclude any director from serving the Company or any subsidiary thereof in any other capacity and receiving compensation therefor.

ARTICLE IV.

Committees of the Board.

Section 1. Executive Committee. The board of directors shall elect from the directors an executive committee.

The board of directors shall fill vacancies in the executive committee by election from the directors.

The executive committee shall fix its own rules of procedure and shall meet where and as provided by such rules or by resolution of the board of directors, but in every case the presence of at least three members of the committee shall be necessary to constitute a quorum for the transaction of business.

In every case the affirmative vote of a majority of all of the members of the committee present at the meeting shall be necessary for the adoption of any resolution.

Section 2. Membership and Powers. The executive committee shall consist of five members in addition to the Chairman of the Board, who by virtue of his office shall be a member of the executive committee and chairman thereof. Unless otherwise ordered by the board of directors, each elected member of the executive committee shall continue to be a member thereof until the expiration of his term of office as a director.

The executive committee, subject to any limitations prescribed by the board of directors, shall have special charge of all financial accounting, legal and general administrative affairs of the Company. During the intervals between the meetings of the board of directors the executive committee shall have all the powers of the board in the management of the business and affairs of the Company, including the power to authorize the seal of the Company to be affixed to all papers which require it, except that said committee shall not have the power of the board (i) to fill vacancies in the board, (ii) to amend the bylaws, (iii) to adopt a plan of merger or consolidation, (iv) to recommend to the stockholders the sale, lease, exchange, mortgage, pledge or other disposition of all or substantially all of the property and assets of the Company otherwise than in the usual and regular course of its business, or (v) to recommend to the stockholders a voluntary dissolution of the Company or a revocation thereof.

Section 3. Other Committees. The board of directors may, by resolution or resolutions passed by a majority of the whole board, designate one or more other committees, each committee to consist of two or more of the directors of the Company, which, to the extent provided in said resolution or resolutions, shall have and may exercise the powers of the board of directors in the management of the business and affairs of the Company, and may have power to authorize the seal of the Company to be affixed to all papers which may require it. Such committee or committees shall have such name or names as may be determined from time to time by resolution adopted by the board of directors.

ARTICLE V.

Officers.

Section 1. Number. The principal officers of the Company shall be a Chairman of the Board, President, one or more Vice Presidents (which may be designated as Executive or Senior Vice President(s)), a Secretary, a Treasurer, and a Controller. No officers except the Chairman of the Board and President need be directors. One person may hold the offices and perform the duties of any two or more of said offices.

Section 2. Election and Term of Office. The principal officers of the Company shall

be chosen annually by the board of directors at the annual meeting thereof. Each such officer shall hold office until his successor shall have been chosen and shall qualify, or until his death or until he shall resign or shall have been removed in the manner hereinafter provided.

Section 3. Subordinate Officers. In addition to the principal officers enumerated in Section 1 of this Article V, the Company may have one or more Assistant Vice Presidents, one or more Assistant Treasurers, one or more Assistant Secretaries and such other officers, agents and employees as the board of directors may deem necessary, each of whom shall hold office for such period, have such authority, and perform such duties as the board or the President may from time to time determine. The board of directors may delegate to any principal officer the power to appoint and to remove any such subordinate officers, agents or employees.

Section 4. Compensation of Principal Officers. The salaries of the principal officers shall be fixed from time to time either by the board of directors or by a committee of the board to which such power may be delegated. The salaries of any other officers shall be fixed by the President or by a committee or committees to which he may delegate such power.

Section 5. Removal. Any officer may be removed, either with or without cause, at any time, by resolution adopted by the board of directors at any regular meeting of the board or at any special meeting of the board called for the purpose at which a quorum is present.

Section 6. Vacancies. A vacancy in any office may be filled for the unexpired portion of the term in the manner prescribed in these bylaws for election or appointment to such office for such term.

Section 7. Chairman of the Board. The Chairman of the Board shall preside at all meetings of the stockholders and directors at which he may be present. He shall have such other authority and responsibility and perform such other duties as may be determined by the board of directors.

Section 8. President. The President shall be the chief executive officer of the Company and as such shall have general supervision and management of the affairs of the Company subject to the control of the board of directors. He may enter into any contract or execute any deeds, mortgages, bonds, contracts or other instruments in the name and on behalf of the Company except in cases in which the authority to enter into such contract or execute and deliver such instrument, as the case may be, shall be otherwise expressly delegated. In general he shall perform all duties incident to the office of President as herein defined and all such other duties as from time to time may be assigned to him by the board of directors. In the absence of the Chairman of the Board, the President shall preside at meetings of the stockholders and directors.

Section 9. Vice Presidents. The Vice Presidents, in order of their seniority unless otherwise determined by the board of directors, shall in the absence or disability of the President perform the duties and exercise the powers of such offices. The Vice Presidents shall perform such other duties and have such other powers as the President or the board of directors may from time to time prescribe.

Section 10. Secretary. The Secretary shall attend all sessions of the board and all meetings of the stockholders, and record all votes and the minutes of all proceedings in a book to be kept for that purpose, and shall perform like duties for the committees of the board of directors when required. He shall give or cause to be given, notice of all meetings of the stockholders and of special meetings of the board of directors, and shall perform such other duties as may be prescribed by the board of directors, or the President, under whose supervision he shall be. He shall keep in safe custody the seal of the Company and, when authorized by the board of directors, affix the same to any instrument requiring it, and when so affixed it shall be attested by his signature or by the signature of the Treasurer or an Assistant Secretary.

Section 11. Treasurer. The Treasurer shall have custody of the corporate funds and securities and shall keep full and accurate accounts of receipts and disbursements in the books belonging to the Company, and shall deposit all moneys and other valuable effects in the name and to the credit of the Company in such depositories as may be designated from time to time by the Board of Directors.

He shall disburse the funds of the Company as may be ordered by the board, taking proper vouchers for such disbursements, and shall render to the President and board of directors at the regular meetings of the board, or whenever they may require it, an account of the financial condition of the Company.

If required by the board of directors, he shall give the Company a bond, in such sum and with such surety or sureties as shall be satisfactory to the board, for the faithful performance of the duties of his office, and for the restoration to the Company, in case of his death, resignation, retirement or removal from office, of all books, papers, vouchers, money and other property of whatever kind in his possession or under his control belonging to the Company.

Section 12. Controller. The Controller shall be in charge of the accounts of the Company and shall perform such duties as from time to time may be assigned to him by the President or by the board of directors.

ARTICLE VI.

Shares and Their Transfer.

Section 1. Certificates for Stock. Certificates for shares of capital stock of the Company shall be numbered, and shall be entered in the books of the

Company, in the order in which they are issued.

Section 2. Regulations. The board of directors may make such rules and regulations as it may deem expedient, not inconsistent with the certificate of incorporation or these bylaws, concerning the issue, transfer and registration of certificates for shares of capital stock of the Company. It may appoint, or authorize any principal officer or officers to appoint, one or more transfer clerks or one or more transfer agents and one or more registrars, and may require all such certificates to bear the signature or signatures of any of them.

Section 3. Stock Certificate Signature. The certificates for shares of the respective classes of such stock shall be signed by, or in the name of the Company by, the Chairman of the Board, the President or any Vice President and the Treasurer or an Assistant Treasurer, or the Secretary or an Assistant Secretary, and where signed (a) by a transfer agent or an assistant transfer agent or (b) by a transfer clerk acting on behalf of the Company and a registrar, the signature of any such Chairman of the Board, President, Vice President, Treasurer, Assistant Treasurer, Secretary or Assistant Secretary may be facsimile. Each such certificate shall exhibit the name of the holder thereof and number of shares represented thereby and shall not be valid until countersigned by a transfer agent.

The board of directors may, if it so determines, direct that certificates for shares of any class or classes of capital stock of the Company be registered by a registrar, in which case such certificates will not be valid until so registered.

In case any officer of the Company who shall have signed, or whose facsimile signature shall have been used on, any certificate for shares of capital stock of the Company shall cease to be such officer, whether because of death, resignation or otherwise, before such certificate shall have been delivered by the Company, such certificate shall nevertheless be deemed to have been adopted by the Company and may be issued and delivered as though the person who signed such certificate or whose facsimile signature shall have been used thereon had not ceased to be such officer.

Section 4. Designations, Preferences, etc. on Certificates for Stock. Certificates for shares of capital stock of the Company shall state on the face or back thereof that the Company will furnish without charge to each stockholder who so requests (which request may be addressed to the Secretary of the Company or to a transfer agent) a statement of the designations, preferences and relative, participating, optional or other special rights of each class of stock or series thereof which the Company is authorized to issue and the qualifications, limitations or restrictions of such preferences and/or rights.

Section 5. Stock Ledger. A record shall be kept by the Secretary or by any other officer, employee or agent designated by the board of directors of the name of the person, firm, or corporation holding the stock represented by such certificates, the number of shares

represented by such certificates, respectively, and the respective dates thereof, and in case of cancellation the respective dates of cancellation.

Section 6. Cancellation. Every certificate surrendered to the Company for exchange or transfer shall be canceled, and no new certificate or certificates shall be issued in exchange for any existing certificate until such existing certificate shall have been so canceled.

Section 7. Transfers of Stock. Transfers of shares of the capital stock of the Company shall be made only on the books of the Company by the registered holder thereof or by his attorney thereunto authorized on surrender of the certificate or certificates for such shares properly endorsed and the payment of all taxes thereon. The person in whose name shares of stock stand on the books of the Company shall be deemed the owner thereof for all purposes as regards the Company; provided, however, that whenever any transfer of shares shall be made for collateral security, and not absolutely, such fact, if known to the Secretary or the transfer agent making such transfer, shall be so expressed in the entry of transfer.

Section 8. Closing of Transfer Books. The board of directors may by resolution direct that the stock transfer books of the Company be closed for a period not exceeding 60 days preceding the date of any meeting of the stockholders, or the date for the payment of any dividend, or the date for the allotment of any rights, or the date when any change or conversion or exchange of capital stock of the company shall go into effect, or for a period not exceeding 60 days in connection with obtaining the consent of stockholders for any purpose. In lieu of such closing of the stock transfer books, the board may fix in advance a date, not exceeding 60 days preceding the date of any meeting of stockholders, or the date for the payment of any dividend, or the date for the allotment of rights, or the date when any change or conversion or exchange of capital stock shall go into effect or a date in connection with obtaining such consent, as a record date for the determination of the stockholders entitled to notice of, and to vote at, such meeting, and any adjournment thereof, or to receive payment of any such dividend, or to receive any such allotment of rights, or to exercise the rights in respect of any such change, conversion, or exchange of capital stock or to give such consent, as the case may be, notwithstanding any transfer of any stock on the books of the Company after any record date so fixed.

ARTICLE VII.

Miscellaneous Provisions.

Section 1. Corporate Seal. The board of directors shall provide a corporate seal which shall be in the form of a circle and shall bear the name of the Company and words and figures showing that it was incorporated in the State of Delaware in the year 1964. The Secretary shall be the custodian of the seal. The board of directors may authorize a duplicate seal to be kept and used by any other officer.

Section 2. Fiscal Year. The fiscal year of the Company shall be fixed by resolution of the board of directors.

Section 3. Voting of Stocks Owned by the Company. The board of directors may authorize any person in behalf of the Company to attend, vote and grant proxies to be used at

any meeting of stockholders of any corporation in which the Company may hold stock.

Section 4. Dividends. Subject to the provisions of the certificate of incorporation, the board of directors may, out of funds legally available therefor, at any regular or special meeting declare dividends upon the capital stock of the Company as and when they deem expedient. Dividends may be paid in cash, in property, or in shares of capital stock of the Company, subject to the provisions of the certificate of incorporation. Before declaring any dividend there may be set apart out of any funds of the Company available for dividends such sum or sums as the directors from time to time in their discretion deem proper for working capital or as a reserve fund to meet contingencies or for equalizing dividends or for such other purposes as the directors shall deem conducive to the interests of the Company.

ARTICLE VIII.

Indemnification of Officers, Directors,
Employees and Agents; Insurance.

Section 1. Indemnification.

(a) The Company may indemnify any person who was or is a party or is threatened to be made a party to any threatened, pending or completed action, suit or proceeding, whether civil, criminal, administrative or investigative (including an action by or in the right of the Company) by reason of the fact that he is or was a director, officer, employee or agent of the Company, or is or was serving at the request of the Company as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise, against expenses (including attorneys' fees) and, except for an action by or in the right of the Company, judgments, fines and amounts paid in settlement, actually and reasonably incurred by him in connection with such action, suit or proceeding, if he acted in good faith and in a manner he reasonably believed to be in or not opposed to the best interests of the

Company, and, with respect to any criminal action or proceeding, had no reasonable cause to believe his conduct was unlawful. Except for an action by or in the right of the Company, the termination of any action, suit or proceeding by judgment, order, settlement, conviction, or upon a plea of nolo contendere or its equivalent, shall not, of itself, create a presumption that the person did not act in good faith and in a manner which he reasonably believed to be in or not opposed to the best interests of the Company, and, with respect to any criminal action or proceeding, had reasonable cause to believe that his conduct was unlawful. With respect to an action by or in the right of the Company, no indemnification shall be made in respect of any claim, issue or matter as to which such person shall have been adjudged to be liable for negligence or misconduct in the performance of his duty to the Company unless and only to the extent that the Delaware Court of Chancery or the court in which such action or suit was brought shall determine upon application that, despite the adjudication of liability but in view of all the circumstances of the case, such person is fairly and reasonably entitled to indemnity for such expenses which such court shall deem proper.

(b) To the extent that a director, officer, employee or agent of the Company has been successful on the merits or otherwise in defense of any action, suit or proceeding referred to

in subsection (a) or in defense of any claim, issue or matter therein, he shall be indemnified against expenses (including attorneys' fees) actually and reasonably incurred by him in connection therewith.

(c) Any indemnification under subsection (a) (unless ordered by a court) shall be made by the Company only as authorized in the specific case upon a determination that indemnification of the director, officer, employee or agent is proper in the circumstances because he has met the applicable standard of conduct set forth in subsection (a). Such determination shall be made (i) by the board of directors by a majority vote of a quorum consisting of directors who were not parties to such action, suit or proceeding, or (ii) if such a quorum is not obtainable, or, even if obtainable a quorum of disinterested directors so directs, by independent legal counsel in a written opinion, or (iii) by the stockholders.

(d) Expenses incurred in defending a civil or criminal action, suit or proceeding may be paid by the Company in advance of the final disposition of such action, suit or proceeding as authorized by the board of directors in the manner provided in subsection (c) upon receipt of an undertaking by or on behalf of the director, officer, employee or agent to repay such amount unless it shall ultimately be determined that he is entitled to be indemnified by the Company as authorized in this section.

(e) The indemnification provided by this Article shall not be deemed exclusive of any other rights to which those seeking indemnification may be entitled under any agreement, vote of stockholders or disinterested directors or otherwise, both as to action in their official capacities and as to action in other capacities while holding such offices, and shall continue as to a person who has ceased to be a director, officer, employee or agent and shall inure to the benefit of the heirs, executors and administrators of such a person.

Section 2. Insurance. The Company may purchase and maintain insurance on behalf of any person who is or was a director, officer, employee or agent of the Company, or is or was serving at the request of the Company as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise against any liability asserted against him and incurred by him in any such capacity, or arising out of his status as such, whether or not the Company would have the power to indemnify him against such liability under the provisions of either the General Corporation Law of the State of Delaware or of these bylaws.

ARTICLE IX.

Amendments.

The bylaws of the Company may be altered, amended or repealed either by the affirmative vote of a majority of the stock issued and outstanding and entitled to vote in respect thereof and represented in person or by proxy at any annual or special meeting of the stockholders, or by the affirmative vote of a majority of the directors then in office given at any regular or special meeting of the board of directors. Bylaws, whether made or altered by the stockholders or by the board of directors, shall be subject to alteration or repeal by the stockholders as in this Article provided.

EXHIBIT 13

PETROLEUM

[GRAPH--INCOME CONTRIBUTION*--EXPLORATION AND PRODUCTION]

[GRAPH--CAPITAL EXPENDITURES--EXPLORATION AND PRODUCTION]

[GRAPH--NET HYDROCARBONS PRODUCTION]

EXPLORATION AND PRODUCTION

(Thousands of dollars)	1995	1994
Income contribution(1)	$ 29,506	45,253
United States	4,841	18,128
International	24,665	27,125
Total assets	1,149,433	1,292,402
United States	317,422	386,830
International	832,011	905,572
Capital expenditures(2)	231,718	286,348
United States	71,186	79,451
International	160,532	206,897
Crude oil and liquids produced - barrels a day	57,015	51,328
United States	13,736	13,355
International	43,279	37,973
Natural gas sold - MCF a day	251,726	256,258
United States	189,250	195,555
International	62,476	60,703

1 Before unusual or infrequently occurring items.
2 Prior year amounts reclassified to conform to 1995 presentation.

WORLDWIDE OVERVIEW

Murphy is engaged in exploration and production operations throughout the world. In the U.S., the Company is one of the largest operators in the Gulf of Mexico and has interests onshore, primarily in Louisiana, Texas, and South Arkansas. The Company also explores for and produces light oil, heavy oil, and natural gas in western Canada, where a substantial ownership of heavy oil reserves is providing a growing source of the Company's crude oil production. Murphy's Canadian activities also include an interest in the world's largest synthetic crude oil operation and interests in two oil fields offshore eastern Canada--Hibernia, which is under development, and Terra Nova, where development plans are being prepared. The Company has long been active in the U.K. sector of the North Sea, where an ownership in the giant Ninian oil field has provided an important source of crude oil production for a number of years. This field has now been joined by three other oil properties in various stages of production or development--"T" Block, where Tiffany and Toni fields were placed on stream in late 1993 and where the Thelma and Southeast Thelma fields are expected to commence production in late 1996; the Mungo and Monan fields, where development was approved in 1995; and the Schiehallion field, an important discovery west of the Shetland Islands on Block 204/25a. Development of the Schiehallion field is expected to be approved early in 1996. The Company also has producing properties in Spain and Ecuador and conducts an ongoing exploration program in other parts of the world, with Peru, offshore China, and Pakistan currently among areas of particular interest.

The exploration and production function represents the Company's best opportunity for extraordinary growth. Murphy's exploration programs emphasize those areas where we have established production and the related data base and high-risk prospects that have potential for significant reserve additions. The

Company also has the technical expertise to identify frontier prospects, along with the resources to acquire significant ownership positions therein, and attempts to do so early in the exploration cycle of emerging basins. Leveraging that ownership position to fund exploratory drilling is an available option.

Earnings from the Company's exploration and production activities, excluding unusual or infrequently occurring items, totaled $29.5 million in 1995 compared to $45.2 million a year ago. The decrease was due primarily to lower sales prices for natural gas in the U.S. and higher exploration expenses, offset in part by higher crude oil production and sales prices. Production of crude oil and liquids increased 11 percent to 57,015 barrels a day, with all major oil-producing areas experiencing increases. Total natural gas sales were 251.7 million cubic feet a day, down two percent. On an energy equivalent basis, the Company's 1995 production was up five percent to a

[GULF OF MEXICO MAP]

record 98,969 barrels a day.

Capital expenditures for exploration and production totaled $231.7 million in 1995 compared to $286.3 million in 1994. The 1996 budget provides for a 40-percent increase in capital expenditures for exploration and production activities, primarily due to higher levels of spending on development projects that will contribute significant new production commencing in 1997.

As shown in the schedules on pages 43 and 44, proved reserves of crude oil and liquids increased 6.4 million barrels, while natural gas reserves were essentially unchanged. Reserve additions in the U.S. totaled 5.1 million barrels of oil and 70.7 billion cubic feet of natural gas. Additions from discoveries included Viosca Knoll Block 783 and West Cameron Blocks 521 and 631. In the U.K., the decision to develop the Mungo, Monan, Thelma, and Southeast Thelma fields added 20.3 million barrels of oil and 19.8 billion cubic feet of natural gas. Other changes included a 3.5-million-barrel downward revision in Ecuador. On an energy equivalent basis, Murphy's reserves totaled 333.8 million barrels at the end of 1995 compared to 327.6 million barrels at year-end 1994.

A review geographically of the Company's principal exploration and production activities is presented in the sections that follow. The Company's working interest percentage is shown, generally following the name of each field or block, and unless otherwise indicated, average daily production rates are net to the Company after deduction for royalty interests. The terms crude oil production and oil production include natural gas liquids where applicable.

UNITED STATES

Average U.S. crude oil production totaled 13,736 barrels a day in 1995, up three percent from 1994, and natural gas production totaled 189.3 million cubic feet a day, a decrease of three percent from a year ago. Additions to production were primarily provided by workovers and new drilling in existing fields, essentially offset by normal production declines in several of the Company's older fields.

Gulf of Mexico - The Gulf of Mexico is the Company's principal area of interest in the U.S. and offers significant growth potential. In 1995, the Gulf accounted for 69 percent and 89 percent, respectively, of our U.S. oil and natural gas production.

The Ship Shoal Block 113 field (50-70%) is our largest single source of oil production in the U.S. A successful oil well was completed during 1995, and a successful gas well was completed shortly after year-end. While a slower pace of drilling in 1995 resulted in normal decline more than offsetting new production, additional wells are planned in 1996 for this field. Oil production averaged 3,850 barrels a day in 1995 compared to 4,239 in 1994, and natural gas production averaged 16.6 million cubic feet a day compared to 16.3 million a year ago.

An interpretation of a 3-D seismic survey over the Ship Shoal Block 222 field (40-44.4%) led to drilling three successful wells during 1995, and additional drilling is planned for 1996. Oil production averaged 734 barrels a day in 1995 compared to 554 in 1994. Natural gas production averaged 3.4 million cubic feet a day in 1995, up from one million in 1994.

Workover activities in the South Timbalier Block 63 field (100%) resulted in substantial production increases during 1995. Average oil production increased from

[GRAPH--CRUDE OIL AND NGL PRODUCTION]

[GRAPH--NATURAL GAS SALES]

[PICTURE APPEARS HERE]

197 barrels a day in 1994 to 506 in 1995, and natural gas production increased from 10.1 million cubic feet a day to 16.2 million in 1995. A drilling program based on 3-D seismic data also commenced on this block in the last quarter of 1995, and initial results are encouraging. A successful natural gas well was placed on stream in December 1995, and another natural gas well was completed and placed on stream shortly after year-end. Additional drilling is planned for 1996. Oil production from the adjacent South Timbalier Block 86 field (86.9%) averaged 376 barrels a day in 1995 compared to 430 in 1994. Natural gas production averaged 5.8 million cubic feet in 1995 compared to 2.7 million in 1994, with a gas discovery placed on stream in April 1994 providing the increase.

Operations to sidetrack an oil well in the South Pelto Block 20 field (50%) were successfully completed during 1995, and average oil production from the field increased to 1,700 barrels a day in 1995 compared to 1,457 in 1994. Average natural gas production declined from 5.4 million cubic feet a day in 1994 to 3.9 million.

Reflecting the nature of the business, production from three of the Company's largest natural gas fields in

the U.S. continued to decline in 1995. Production from the Ship Shoal Block 113A field (100%), which was placed on stream in 1982, averaged 27.8 million cubic feet a day compared to 38.5 million in 1994. At the Matagorda Island Block 604/589 area (62.7%), production averaged 16.2 million cubic feet a day, down from 23.6 million in 1994, and production from Viosca Knoll Blocks 203 and 204 (66.7%) declined from 17.4 million cubic feet a day in 1994 to 15.7 million in 1995.

While field declines are never welcomed, the Company has several projects under way that have the potential to more than offset the rate of decline experienced in 1995. The program that commenced at the end of 1995 at South Timbalier Block 63 should contribute to the effort, but the most important source of new U.S. production in the near-term is Viosca Knoll Block 783 (30%). This block, which is known as the Tahoe field, is located in 1,500 feet of water and is being developed in phases. The first phase, which came on stream in early 1994, included a subsea completion of a previously drilled well that was tied-in to production facilities on a platform 12 miles to the north in 275 feet of water. Natural gas production from the field averaged 14.2 million cubic feet a day in 1995 compared to 9.5 million in 1994. Oil production averaged 480 barrels a day compared to 359 barrels a year ago. The Company currently has a 75-percent interest in production from the field due to disproportionate sharing of first-phase development costs. This interest will be reduced to 30 percent upon payout of the Company's investment in the first phase, which is expected to occur during the first quarter of 1996. Overall performance of the first phase has been excellent, and development of the second phase commenced in the fourth quarter of 1995. Activity in 1996 will include the drilling and completion of three horizontal wells and the completion of a successful horizontal well drilled in 1995. First production from the well drilled in 1995 is scheduled for the fourth quarter of 1996, with full production from the second phase expected in early 1997.

Production is also expected to commence in the third quarter of 1996 from Mobile Block 863 (11.5%), a 1994 natural gas discovery in the Norphlet formation. In addition, two exploratory wells in progress at the end of 1995 resulted in natural gas discoveries in early 1996. A well in West Cameron Block 521 (50%) logged 100 feet of net natural gas sands in two zones. Production facilities are being designed and first production is expected in late 1996. Also, a well drilled in West Cameron Block 631 (60%) found 338 feet of net natural gas sands in five zones. A test of one of the zones flowed at a gross rate of 10.4 million cubic feet a day. A five-well drilling template has been installed, and additional drilling is under way to test other prospects on the block. First production is anticipated in the second quarter of 1997.

The wells drilled on the West Cameron blocks, which were acquired in 1995 at the Central Gulf of Mexico lease sale, were the initial wells of a multi-well program planned

[CANADA MAP]

[OFFSHORE EASTERN CANADA MAP]

[PICTURE APPEARS HERE]

for the Gulf in 1996 to test 3-D generated prospects on recently acquired acreage.

The Company holds a 33.3-percent interest in the Destin Dome Block 56 unit, which includes 11 leases covering 63,360 acres located approximately 40 miles south of Pensacola, Florida. Two wells drilled in the Norphlet formation in prior years have proven an accumulation of natural gas reserves at depths between 22,000 and 23,000 feet, and 64 billion cubic feet of natural gas attributable to these wells are included in the Company's reserves. A third well to further delineate the unit's reserve potential was commenced in the fourth quarter of 1995. The well is expected to reach total depth in the first quarter of 1996.

Other exploration activity during 1995 included an unsuccessful sidetrack of a well drilled in 1994 on Mobile Block 908 (70%). A well drilled on Viosca Knoll Block 988 (25%) found noncommercial quantities of oil and natural gas and was abandoned. Murphy participated in the two 1995 federal lease sales held in the Gulf of Mexico and acquired 40- to 100-percent interests in 14 blocks.

Onshore - U.S. onshore exploration activity in 1995 was principally in South Louisiana. Shortly after year-end, a 19,000-foot exploratory well (50%) in Vermilion Parish, Louisiana, was tested at a gross rate of 6.5 million cubic feet of natural gas a day. An extended 30-day flow test will be required to determine if the field is commercial. Daily production from two wells in the East Riceville field (33.3%), also located in Vermilion Parish, averaged 7.4 million cubic feet of natural gas and 167 barrels of oil in 1995. Production in 1994 averaged eight million cubic feet of natural gas a day and 180 barrels of oil. Infield drilling in 1995 included 10 wells in Louisiana and Texas, all of which were successful.

Property dispositions - In late 1995, the Company announced its intention to sell its interests in substantially all of its onshore properties in the U.S. and 20 nonstrategic properties in the Gulf of Mexico. The properties targeted for sale accounted for approximately seven percent and three percent, respectively, of the Company's 1995 worldwide production and year-end reserves.

CANADA

Production of crude oil in Canada increased seven percent in 1995 to 22,853 barrels a day. Light oil production decreased seven percent to 5,157 barrels a day, while heavy oil production increased 30 percent to 8,864. The increase in heavy oil production was due primarily to an aggressive drilling program and the acquisition of additional interests in heavy oil properties in Alberta. Although gross production of synthetic crude oil in 1995 set a new record for the sixth consecutive year, net volumes to the Company were down three percent to 8,832

barrels a day due to an increase in net profit royalties caused by higher oil prices. Natural gas production of 40.9 million cubic feet a day was up eight percent from a year ago. The 1995 production volumes for both oil and natural gas were at record levels.

The Company conducted an active development program in 1995 that included three wells to develop light oil. However, primary emphasis was placed on the development of heavy oil, and the 1995 program included 27 successful horizontal wells and 15 successful vertical wells. Five successful vertical wells were drilled to develop natural gas.

Murphy's exploration program in Canada during 1995 focused on light oil and natural gas prospects. Four light oil wells drilled during the year were put on production near year-end, and three natural gas wells, including one drilled in the Foothills of northeastern British Columbia, will be tested in early 1996. One successful heavy oil exploration well was also drilled during the year. The Company also acquired a 25-percent interest in an exploration license in the Jeanne d'Arc Basin, offshore Newfoundland, located midway between the Hibernia and Terra Nova oil fields.

The Company has a five-percent interest in the Syncrude project, the world's largest oil sands mining and upgrading operation. This project is located on 157,990 acres leased from the province of Alberta in the Athabasca oil sands area near Fort McMurray. Syncrude combines the technologies of mining, extraction, and upgrading to convert oil sands into synthetic crude oil. The deposits are mined by large draglines and moved to an extraction plant, where the oil sands are mixed with hot water, steam, and caustic soda to produce a slurry, from which the oil floats as a froth. The froth is treated to remove water and solids and is fed into an upgrading process in the form of bitumen, which is then "cracked" into naphtha, light gas oil, and heavy gas oil streams. These streams are hydrotreated to remove sulfur and nitrogen impurities and mixed to form synthetic crude oil. The current Syncrude license expires in the year 2025.

Construction of the facilities for the Hibernia oil field (6.5%) in the Grand Banks area, offshore Newfoundland, continued throughout 1995. First production from this field, discovered in 1979, is expected to occur in late 1997 or early 1998, with peak production anticipated at 135,000 gross barrels of oil a day. Gross recoverable reserves are estimated to be 615 million barrels. The central production facility for the Hibernia field is a Gravity Base Structure (GBS)--the first to be constructed to resist the impact of an iceberg. At year-end, the GBS was approximately 80 percent complete. In 1995, the main topside modules, which were constructed at various locations around the world, were delivered to the construction site, where they were joined into a single integrated unit. The GBS and the modules will be mated prior to towing the completed structure to the production site. Tow-out is scheduled for the summer of 1997.

In December 1995, the owners of the Terra Nova oil field (10.7%), located approximately 20 miles southeast of Hibernia, commenced preparation of the Development Plan Application (DPA) for the field. The development plan will include utilization of floating production system technology with "ice-avoidance" criteria, rather than the "ice-resistance" criteria of the GBS for Hibernia. In addition, the project is to be developed by employing a contractor alliance arrangement where the owners, contractors, and suppliers work together to provide major project components. It is anticipated that the DPA will be filed with the Newfoundland government in the second quarter of 1996. Gross recoverable reserves for Terra

[NORTH SEA MAP]

[SCHEMATIC APPEARS HERE]

Nova are estimated to be between 300 and 400 million barrels of oil, with peak production estimated at 100,000 barrels a day. Project sanction is expected in 1997.

UNITED KINGDOM

Production from the Ninian field (13.8%) averaged 6,784 barrels of oil a day in 1995 compared to 7,883 in 1994. The rate of decline in 1995 was less than forecast primarily due to the success of an infill drilling program, which included the redrilling of four wells to new bottom-hole locations. A recently completed 3-D seismic survey is expected to result in additional infill drilling. Tariff income from the processing of oil and gas from four third-party fields continues to make an important contribution to Ninian's operating results.

Production from "T" Block (11.3%) averaged 8,172 barrels of oil a day in 1995 compared to 5,566 in 1994. "T" Block contains four separate fields--Tiffany, Toni, Thelma, and Southeast Thelma. The first phase of development utilized a conventional steel platform in the Tiffany field, with wells in the Toni field connected to the platform by a subsea system. In 1995, one production well and one water injection well were completed at Tiffany, and an additional injection well is scheduled for completion in the first quarter of 1996. At Toni, the addition of a booster pump to increase water injection capacity is planned for the second half of 1996.

The Thelma and Southeast Thelma fields received government approval for development in April 1995. The fields, which lie approximately five miles south of the Tiffany platform, will also incorporate a subsea system connected to the Tiffany platform. Development drilling commenced in June 1995, and first production is expected in late 1996. Initial production is projected at gross rates of 20,000 barrels of oil a day and 28 million cubic feet of natural gas a day from two wells at Southeast Thelma and one horizontal well at Thelma.

Daily production from the Amethyst field (7.4%) averaged 10.7 million cubic feet of natural gas compared to 10.1 million in 1994. Onshore gas compression commenced in October 1995. Drilling during the year included a successful horizontal development well and two successful exploration wells drilled on the nearby Flowers North and Flowers South prospects. Development of the Flowers discoveries is planned for 1997 by the drilling of extended-reach wells from an existing platform.

Development of the Mungo and Monan fields (12.7%) was approved by the U.K. government in December 1995. The fields will be developed jointly with five other oil and gas fields as part of the Eastern Trough Area Project. The Mungo field will be developed from an unmanned platform, while the Monan field will use a subsea system. Both fields will produce to a central processing facility, a two-platform structure that will provide processing facilities, utilities, and accommodations. First production is expected in late 1998, with peak gross production estimated at 65,000 barrels of oil a day.

Exploration efforts in the

U.K. were concentrated to the west of the Shetland Islands, where an active drilling program was combined with evaluation and acquisition of new acreage. Activity in the Schiehallion field (5.9%), which underlies a portion of the Company's Block 204/25a and adjacent blocks to the north and east, included the drilling of three wells with field partners to establish the southern limits of the field. In addition, an extended test of a horizontal well drilled in the central part of the field recovered more than 700,000 barrels of oil at an average stabilized rate of 18,000 barrels a day. Information gained from these wells and a 3-D seismic survey contributed to an accelerated development program, which anticipates first production in late 1997 or early 1998. Development of the field is expected to be approved in 1996 and calls for the drilling of wells from three subsea drilling centers linked to a floating production storage and offloading vessel. Gross peak production is anticipated to be in excess of 100,000 barrels of oil a day. Gross recoverable reserves are estimated to be between 200 and 400 million barrels. The Company's initial equity interest in the field is 5.9 percent, which is subject to redetermination upon completion of development drilling.

In the 16th Licensing Round, the Company was awarded Block 205/8 (35%) in the West of Shetlands area. A well is planned in 1996 to test the block. The Company was also awarded Blocks 20/19 and 20/20 (25%) in the Central North Sea, where 3-D seismic data was acquired during the latter half of the year in anticipation of drilling in 1996.

ECUADOR

The Company has a 20-percent interest in risk-service contracts (similar to production-sharing contracts) covering Block 16 and the Tivacuno field in Ecuador. In addition, the Capiron field has been unitized as part of Block 16. Block 16 is a 494,000-acre license located east of the Andes mountains in the Oriente Basin. Production from the northern fields--Tivacuno, Capiron, and the Bogi field on Block 16--commenced in mid-1994. Development of the southern fields--Amo, Daimi, Ginta, and Iro--is under way. Initial production from the Amo field commenced in December 1994, and the other three fields should be capable of first production in 1996. However, our combined Ecuador production has been subject to apportionment due to limited export pipeline capacity. As a result, gross production for 1996, which was planned to exceed 50,000 barrels of oil a day, is not expected to substantially exceed the current level of 30,000 barrels a day. The Company's share of production from Ecuador averaged 5,274 barrels of oil a day in 1995 compared to 1,967 in 1994.

SPAIN

Production from the Gaviota field (18%) averaged 3.6 million cubic feet of natural gas a day in 1995 compared to 12.6 million in 1994. This field has been converted into a natural gas storage facility under an agreement with ENAGAS, the Spanish gas distribution company, and production ceased in early

[SCHEMATIC APPEARS HERE]

[PAKISTAN MAP]

1995. The gas storage project, known as ALGA, handles third-party natural gas for a tariff, which covers operating costs and provides a return on capital invested. The project began sustained gas injection in May 1995. Production also commenced from the East Albatros field (18%) in May. This field is located 11 miles west of Gaviota and is produced through a subsea well connected to the Gaviota platform. Production averaged 7.3 million cubic feet of natural gas a day for the year.

GABON

Virtually all of the Company's production in Gabon was from the Breme field (45%). The Breme field permit expired in December 1994, but production continued for a short period in 1995 under a temporary extension granted by the Gabonese government. The government subsequently chose not to renew the permit, and the Company has withdrawn completely from Gabon.

OTHER

During 1995, Murphy acquired a 40-percent interest in three contiguous blocks onshore Pakistan. The blocks--Leiah, Munda, and Tarind--are located in the Middle Indus Basin and cover 4.4 million acres. The work commitment consists of a seismic program that commenced in 1995 and continues into 1996. The Company also has a 100-percent interest in the 6.7-million acre Kharan concession in Pakistan; this concession remained in a force majeure status during 1995. In China, the Company participated in the drilling of an unsuccessful exploratory well on Block 04/36 (45%) in the Bohai Bay. The final well obligation is planned for the second quarter of 1996. Onshore Peru, the Company holds a 100-percent interest in Block 71, which covers 3.1 million acres in the Ucayali Basin. The first exploration period expires in June 1996 and includes a work obligation for certain seismic activity that was substantially completed in 1995. An optional second exploration period, which expires in June 1997, includes a one-well obligation. During 1995, the Company joined a bidding and evaluation group (30%) to acquire and evaluate data in preparation for the First Round of Licensing in the Falkland Islands.

REFINING, MARKETING, AND TRANSPORTATION

(Thousands of dollars)	1995	1994
Income contribution*	$ 2,052	30,203
United States	(3,767)	17,674
International	5,819	12,529
Total assets	680,315	712,929
United States	494,577	500,467
International	185,738	212,462
Capital expenditures	53,602	94,697
United States	27,565	80,272
International	26,037	14,425
Crude oil processed - barrels a day	155,503	140,882
United States	125,157	108,844
International	30,346	32,038
Products sold - barrels a day	161,911	161,130
United States	130,394	120,618
International	31,517	40,512
Average gross margin on products sold - dollars a barrel		
United States	$ .46	1.07
United Kingdom	2.26	2.17

*Before unusual or infrequently occurring items.

WORLDWIDE OVERVIEW

Murphy is engaged in downstream activities in the United States, the United Kingdom, and Canada. In the U.S., operations are conducted in two separate regions. A 100,000-barrel-a-day refinery at Meraux, Louisiana, produces refined petroleum products for distribution over an 11-state area in the southeastern part of the U.S. that is generally referred to as the Gulf Coast market. A four-state area in the upper-Midwest is served by a 35,000-barrel-a-day refinery at Superior, Wisconsin. Operations in the United Kingdom are centered around a 108,000-barrel-a-day refinery, in which the Company has an effective 30-percent interest, at Milford Haven, Wales. Refined products are sold at 986 branded outlets--514 in the U.S. and seven in Canada under the SPUR brand, and 465 in the U.K. primarily under the MURCO brand. Murphy also has varying interests in four crude oil pipeline systems in western Canada, including two of the six systems that export crude oil from Canada to the U.S.

The year 1995 was difficult for the Company's worldwide downstream operations, and earnings, excluding unusual or infrequently occurring items, totaled $2 million in 1995 compared to $30.2 million in 1994. Operations in the U.S. lost $3.8 million compared to earning $17.7 million a year ago. Earnings from operations in the U.K. totaled $.3 million, down from $5.2 million in 1994. The earnings contribution from Canadian operations totaled $5.5 million in 1995 compared to $7.3 million a year ago. The Company's composite average gross margin on product sales in the U.S. was down 57 percent, while sales of refined products increased eight percent. Average margin in the U.K. was up four percent compared to 1994. Sales volumes were down 22 percent compared to 1994, with the reduction primarily in low-margin cargo sales. The decline in Canadian earnings was due primarily to lower crude oil trading volumes and margins.

A key element of Murphy's strategy for its downstream business is a commitment to maintain modern, efficient, and competitive refining and distribution systems. The Company also recognizes its responsibility to operate in an environmentally safe manner. In meeting those objectives, the Company's worldwide downstream capital expenditures in 1995 totaled $53.6 million compared to $94.7 million in 1994. The 1994 expenditures included nearly $25 million to increase sour crude processing capabilities at the Meraux refinery.

UNITED STATES REFINING

The expansion and upgrade program at the Meraux refinery, completed in December 1994, allowed the refinery to take advantage of processing and crude selection opportunities in 1995. We continued the trend of processing higher rates of light-sour and heavy-sweet crudes. Additional sour crude processing capacity exists if warranted by

[GRAPH--INCOME CONTRIBUTION*--REFINING, MARKETING, AND TRANSPORTATION]

[GRAPH--CAPITAL EXPENDITURES--REFINING, MARKETING, AND TRANSPORTATION]

[GRAPH--REFINED PRODUCTS SOLD]

[PICTURE APPEARS HERE]

cost differentials between crudes. In total, the Meraux refinery processed a record 91,940 barrels of crude oil a day, outpacing the previous record set in 1992 by 14 percent. Crude oil for Meraux is supplied through our own domestic production and purchase of third-party domestic and foreign-source crudes.

The Superior refinery also posted impressive throughput results for 1995, with average crude runs of 33,217 barrels a day, the highest in 18 years. In response to demand for asphalt, asphaltic crude runs were emphasized throughout the year. Canadian-source crude continued to account for 78 percent of the refinery's crude slate, with the balance comprised of Williston Basin sweet and sour grades.

Refining capital expenditures in the U.S. were down substantially in 1995, with major expenditures focused on environmental projects. Capital expenditures in 1996 are budgeted to remain near the 1995 amount, with a continuing but diminished level of environmental expenditures, offset by an increased emphasis on engineering for future refinery upgrades.

UNITED STATES MARKETING

Murphy's downstream operations are conducted in 11 southeastern states and four upper-midwestern states. The southeastern system is anchored by our Meraux refinery, located on the Mississippi River. Sales are made through 28 terminals in this system; the terminals are supplied by barge or pipeline, including a jointly owned line that is connected to two common carrier pipelines. In addition, products are shipped by barge and tanker from the refinery's river dock for sale into the wholesale cargo market and transport to marine terminals. Our upper-midwestern distribution system includes 15 terminals owned by others and two Company-owned terminals that are supplied by pipeline. One of the Company-owned terminals, located near Duluth, Minnesota, was acquired in 1995 to better serve customers from the Iron Range of northern Minnesota to areas south of Duluth. Asphalt terminals at Crookston, Minnesota, and Rhinelander, Wisconsin, are

supplied by truck. Asphalt demand remained brisk in our upper-midwestern system during 1995, with a record volume of more than 1.5 million barrels sold through our Company terminals.

Products sold and the initial distribution channels utilized are shown in the following table. Included in the terminal sales volumes are 18,439 barrels a day sold at retail through SPUR branded outlets.

(Barrels a day)	Terminals	Cargo
Gasoline	41,663	21,950
Kerosine	2,095	7,856

Diesel/heating oil	21,141	12,362
Residuals	--	14,795
Asphalt	4,213	--
LPG/other	--	4,602
	69,112	61,565

Several construction sites have been selected for new stations being planned for 1996, including joint ventures with national-brand fast food chains. To improve the convenience of shopping at our stations, we began an aggressive program of installing credit card readers at our pumps. This feature relieves congestion on the driveways and allows customers who only want to purchase fuel to avoid waiting in line to make payment. We also plan to install car wash systems in selected new and existing stations as a one-stop convenience to our customers.

UNITED KINGDOM REFINING

Activities at the Company's jointly owned Milford Haven refinery during 1995 were directed toward meeting impending environmental regulations, reducing operating costs, and improving yields and operating flexibility.

To meet the imposition on October 1, 1996 of regulations reducing the sulfur content of diesel oil to .05 percent, construction of a high-pressure distillate hydrotreater unit is progressing on schedule for a September start-up. The new unit is also capable of producing low-sulfur No. 2 fuel oil. Cost reduction plans in the detailed design phase include modification of the cat cracker to reduce catalyst consumption. Also under way is a study reviewing operations of the crude unit to reduce energy consumption, enhance product yields, and increase flexibility in the selection of feedstocks.

During 1995, Murphy processed an average of 30,346 barrels of crude oil a day at the Milford Haven refinery, down five percent from 1994. The refinery utilizes North Sea crudes purchased in the spot market. Transportation to the refinery is provided by tankers chartered at spot rates.

UNITED KINGDOM MARKETING

The distribution system for refined products in the U.K. includes three rail-fed terminals owned by the Company and eight terminals owned by others, where products are received in exchange for deliveries from the Company's terminals.

Service station profitability came under severe pressure in

[UNITED STATES MAP]

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[UNITED KINGDOM MAP]

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1995, as major oil companies defended their market share against the supermarkets, which have garnered about 20 percent of the market. The Company's service stations remained profitable over the year, although average gross margin was down seven percent from 1994. Sales volume through our branded outlets fell almost five percent from last year to 8,334 barrels a day, reflecting our pricing strategy of emphasizing profitability over market share. Six Company-owned stations were closed as uneconomic, and we expect further reductions in 1996.

Products available from Milford Haven that are not required in our retail and wholesale markets, 22,872 barrels a day in 1995, are sold in the bulk cargo markets. To reduce our exposure to the gasoline spot market in 1995, a year characterized by poor demand and weak pricing, we sold an average of 2,200 barrels a day on a contract basis at higher than spot prices.

The Company's three terminals operated profitably in 1995. Renegotiation of the rail freight contract late in the year and expected higher terminal throughputs should translate into improved results in 1996 for our terminaling operations.

CANADA

The Company's western Canadian pipelines, which comprise four oil-gathering and transportation systems, enjoyed a nine-percent increase in throughputs in 1995. Throughputs for the Murphy-operated Manito (52.5%) and Cactus Lake/Bodo (13.1%/41.3%) heavy oil pipeline systems, both connected to the Interprovincial Pipe Line, were up a combined 12 percent over 1994 due to increased heavy oil production in the area, a major part of which was from the Company's fields. For 1995, Manito averaged 45,562 barrels a day and Cactus Lake/Bodo averaged 33,707. Throughputs for the Milk River pipeline (100%) increased 26 percent to a record 67,508 barrels a day, as demand for Canadian crude in the Billings, Montana, refining area increased substantially. The pipeline was expanded during the year by construction of a 12-inch loop from the Milk River terminal to the U.S./Canadian border and a station expansion, which pushed capacity from 70,000 to over 100,000 barrels a day. Pipelines connected to the Milk River line were also expanded in 1995, thus providing the collective means to deliver substantial volume increases into the Billings area to further replace the declining U.S. crude supply. Throughputs for 1995 at the Wascana pipeline system (100%), also a cross-border pipeline, declined from the prior year by 23 percent to an average of 26,943 barrels a day. Demand was down due to the loss in May of a 12,000-barrel-a-day contract. Since then, the available capacity has not been fully

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utilized. The Company continues working with other U.S. pipelines in the region to expand capacity to higher-demand areas, with particular emphasis on markets in the Salt Lake City area.

Crude oil trading earnings were down in 1995 due to lower margins and a sharp drop in demand for Canadian heavy crudes during the fourth quarter. The Company also operates a fleet of trucks that transport crude oil and natural gas liquids, and earnings from these activities were up compared to a year ago. Sales of refined products at the Company's retail outlets in Thunder Bay, Ontario, which are supplied from our Superior refinery, increased 15 percent over the previous year, but margins were squeezed by strong price competition.

[WESTERN CRUDE OIL PIPELINE SYSTEMS MAP]

[GRAPH--CANADIAN PIPELINE THROUGHPUTS]

FARM, TIMBER, AND REAL ESTATE

[GRAPH--INCOME CONTRIBUTION--FARM, TIMBER, AND REAL ESTATE]

[GRAPH--CAPITAL EXPENDITURES--FARM, TIMBER, AND REAL ESTATE]

[GRAPH--SALES OF FINISHED LUMBER]

(Thousands of dollars)	1995	1994
Income contribution	$ 9,005	17,470

Total assets	163,834	155,583
Capital expenditures	9,133	11,403
Lumber sales - thousand board feet	140,549	138,377
Residential lots sold	53	99
Land owned - acres		
Farm	36,000	36,000
Timber	341,000	341,000
Real estate	9,000	10,000

Through its wholly owned subsidiary, Deltic Farm & Timber Co., Inc., the Company owns 36,000 acres of farmland in South Arkansas and North Louisiana, 341,000 acres of southern pine timberland and two sawmills in Arkansas, and is developing the premier residential community in Little Rock, Arkansas. Those activities produced earnings of $9 million in 1995 compared to $17.5 million in 1994, a decrease of 49 percent. Earnings from all operating segments declined from a year ago, with timber operations accounting for most of the decrease.

Deltic's timber operations earned $8.7 million in 1995, down from the record $14.7 million earned in 1994. The decline follows three consecutive years of earnings growth in our timber operations. Sales of finished lumber totaled 140.5 million board feet, an increase of two percent from the 138.4 million board feet sold in 1994. However, the average sales price for finished lumber declined 12 percent to $318 per thousand board feet. Pretax mill margins of $12 per thousand board feet declined 86 percent from the record margins of 1994 because of lower sales prices and an increase in log costs. An expansion of the Waldo sawmill, including an addition of two steam-dry kilns, two boilers, and a band mill, was completed in the third quarter of 1995. The expansion will provide Deltic the product flexibility needed to extract maximum value from each log processed, and also will offer entrance into the export market in 1996. Sales of pine sawtimber from Deltic's fee lands decreased 12 percent to 35.7 million board feet in 1995. Pine sawtimber prices were strong during the first six months of the year before declining in the last half of 1995. Approximately 70 percent of Deltic's sawtimber sales were made during the first half of the year, and the average sales price increased nine percent in 1995 to $406 per thousand board feet. Pine pulpwood sales were down slightly from 1994 levels and totaled 12,799 cords.

A site was selected in Union County, Arkansas, for construction of a 50-percent-owned medium density

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fiberboard (MDF) plant. MDF, which is used in the furniture, flooring, and molding industries, is manufactured from sawmill residuals (chips, shavings, and sawdust) held together by an adhesive bond. The plant will have an annual production capacity of 150 million square feet, making it one of the largest of its type in the world. Construction is scheduled to commence in mid-1996, and first production is expected in early 1998.

Real estate operations earned $.5 million in 1995, down 74 percent from the $1.9 million earned in 1994. Lot sales at Chenal Valley, Deltic's 4,300-acre planned community in Little Rock, Arkansas, declined from 99 a year ago to 53 in 1995. Construction of the first office building in Chenal Valley commenced in the fourth quarter of 1995. The Company-owned building will contain approximately 50,000 square feet, of which approximately 25,000 square feet was leased at year-end. Sale of commercial acreage will be actively pursued in 1996.

Farming operations earned $.2 million in 1995, down from $1.1 million earned in 1994. Hot, dry conditions during the last half of the growing season adversely affected the yield per acre for all crops. Cotton yields declined 15 percent to 749 pounds per acre, soybean yields were down 33 percent to 27 bushels per acre, and corn yields declined 24 percent to 86 bushels per acre.

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FINANCIAL REVIEW

SELECTED FINANCIAL INFORMATION

(Thousands of dollars except per share data)	1995	1994	1993	1992	1991
RESULTS OF OPERATIONS FOR THE YEAR(1)					
Sales and other operating revenues(2)	$1,691,242	1,668,822	1,625,662	1,585,482	1,568,995
Net cash provided by operating activities	322,939	337,283	362,973	284,159	213,635
Income (loss) from continuing operations	(118,612)	106,628	86,798	62,761	(9,607)
Income (loss) before extraordinary item and cumulative effect of changes in accounting principles	(118,612)	106,628	86,798	86,616	(11,157)
Net income (loss)	(118,612)	106,628	102,136	105,565	(11,157)
Per Common share					
Income (loss) from continuing operations	(2.64)	2.37	1.94	1.40	(.24)
Income (loss) before extraordinary item and cumulative effect of changes in accounting principles	(2.64)	2.37	1.94	1.93	(.28)
Net income (loss)	(2.64)	2.37	2.28	2.35	(.28)
Dividends	1.30	1.30	1.25	1.20	1.20
Percentage return on					
Average stockholders' equity	(9.3)	8.6	8.4	8.8	(1.1)
Average borrowed and invested capital	(7.9)	8.0	8.4	9.7	1.5
Average total assets	(5.1)	4.8	5.0	5.3	(.6)
CAPITAL EXPENDITURES FOR THE YEAR					
Exploration and production(2, 3)	$ 231,718	286,348	520,086	138,129	147,965
Refining, marketing, and transportation	53,602	94,697	86,885	68,073	63,143
Farm, timber, and real estate	9,133	11,403	9,674	6,017	2,858
Corporate and other	1,831	4,876	4,034	1,477	2,203
	$ 296,284	397,324	620,679	213,696	216,169
FINANCIAL CONDITION AT YEAR-END					
Current ratio	1.25	1.18	1.32	1.87	1.30
Working capital	$ 104,509	79,594	130,242	371,682	156,204
Net property(2)	1,487,232	1,670,934	1,510,281	1,048,744	1,121,106
Total assets	2,119,113	2,312,032	2,168,859	1,936,514	2,174,626
Long-term obligations(4)	193,935	172,452	109,218	24,929	193,152
Stockholders' equity	1,101,145	1,270,679	1,222,350	1,200,088	1,200,819
Per share	24.56	28.34	27.28	26.76	26.71
Long-term obligations(4) - percent of capital employed	15.0	11.9	8.2	2.0	13.9

1 Includes effects on income of unusual or infrequently occurring items in 1995, 1994, and 1993 that are detailed in Management's Discussion and Analysis, page 21. Also, unusual or infrequently occurring items in 1992 and 1991 resulted in an increase (decrease) to net income of $50,665, $1.13 a share, and $(67,333), $(1.71) a share, respectively.

2 Prior year amounts have been reclassified to conform to 1995 presentation.

3 Includes amounts expensed and cost of assets acquired by assuming directly related liabilities.

4 Includes nonrecourse debt at December 31, 1995, 1994, and 1993 of $171,499, $122,638 and $87,509, which was 13.2 percent, 8.5 percent, and 6.6 percent, respectively, of capital employed.

[GRAPH--INCOME EXCLUDING UNUSUAL ITEMS]

[GRAPH--NET CASH PROVIDED BY OPERATING ACTIVITIES]

[GRAPH--STOCKHOLDERS' EQUITY AT YEAR-END]

MANAGEMENT'S DISCUSSION AND ANALYSIS

RESULTS OF OPERATIONS

The Company reported a net loss in 1995 of $118.6 million, $2.64 a share, compared to net income in 1994 of $106.6 million, $2.37 a share. In 1993, the Company earned $102.1 million, $2.28 a share. The loss in 1995 included after-tax charges of $168.4 million, $3.75 a share, from an asset write-down under provisions of Statement of Financial Accounting Standards No. 121 (SFAS No. 121), which deals with impairment of the carrying value of long-lived assets, and $4.2 million, $.10 a share, related to reduction-in-force programs. Results of operations for the three years ended December 31, 1995 also included other unusual or infrequently occurring items that resulted in net gains of $20.6 million, $.46 a share, in 1995; $20.3 million, $.45 a share, in 1994; and $25.7 million, $.57 a share, in 1993. The 1993 net gain included $15.3 million, $.34 a share, from adoption of new accounting standards.

Income before unusual or infrequently occurring items totaled $33.4 million in 1995, a decrease of $52.9 million compared to 1994. Earnings from the Company's exploration and production operations declined $15.7 million, and income from the refining, marketing, and transportation function was down $28.2 million. Earnings from farm, timber, and real estate operations declined $8.5 million, and the cost of corporate activities increased $.5 million compared to 1994.

In 1994, income before unusual or infrequently occurring items was $86.3 million, an increase of $9.9 million compared to 1993. Earnings from exploration and production operations improved by $8.3 million, while income from refining, marketing, and transportation declined $1.3 million. Income from farm, timber, and real estate operations increased $4.4 million, and the cost of corporate functions increased $1.5 million compared to 1993.

In the following table, the Company's results of operations for the three years ended December 31, 1995 are presented by function. Unusual or infrequently occurring items, which can obscure underlying trends of operating results and affect comparability between years, are set out separately. A review of the information presented follows the table.

(Millions of dollars)	1995	1994	1993
Exploration and production			
United States	$ 4.8	18.1	32.7
Canada	21.7	15.1	6.3
United Kingdom	6.4	6.0	3.5
Other international	(3.4)	6.0	(5.6)
	29.5	45.2	36.9
Refining, marketing, and transportation			
United States	(3.8)	17.7	11.2
United Kingdom	.3	5.2	11.7
Canada	5.5	7.3	8.6
	2.0	30.2	31.5
Farm, timber, and real estate	9.0	17.5	13.1
Corporate and other	(7.1)	(6.6)	(5.1)
Income before unusual or infrequently occurring items	33.4	86.3	76.4
Refund and settlement of income tax matters	13.6	6.4	14.4
Impairment of long-lived assets	(168.4)	--	--
Provision for reduction-in-force	(4.2)	--	--
Adjustment of estimates for self-insured liabilities	7.0	--	--
Settlement of DOE matters	--	13.9	--
Provision for environmental remediation matters	--	--	(4.0)
Cumulative effect of changes in accounting principles	--	--	15.3
Net income (loss)	$ (118.6)	106.6	102.1

EXPLORATION AND PRODUCTION - Earnings from exploration and production operations before unusual or infrequently occurring items were $29.5 million in 1995, $45.2 million in 1994, and $36.9 million in 1993. The decrease in 1995 earnings was due to a three-percent reduction in natural gas sales in the U.S., a 14-percent decline in the average sales price for U.S. natural gas, and a 54-percent increase in exploration expenses. Partial offsets were an 11-percent increase in crude oil and liquids production and higher crude oil sales prices. A 50-percent increase in crude oil and liquids production and a seven-percent reduction in

[GRAPH--INCOME CONTRIBUTION BY OPERATING FUNCTION*]

[GRAPH--RANGE OF U.S. CRUDE OIL SALES PRICES]

[GRAPH--RANGE OF U.S. NATURAL GAS SALES PRICES]

exploration expenses contributed to the increase in 1994 earnings. These improvements were offset in part by lower average crude oil sales prices in most of the Company's producing areas and nine-percent reductions in natural gas sales volumes and prices in the U.S.

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 46 and 47. A summary of oil and gas revenues is presented in the following table.

(Millions of dollars)	1995	1994	1993
United States			
Crude oil	$ 82.2	73.7	81.7
Natural gas	112.8	136.1	165.8
Canada			
Crude oil	68.3	54.2	54.1
Natural gas	14.5	19.7	16.4
Synthetic oil	55.7	52.7	--
United Kingdom			
Crude oil	92.6	77.8	38.4
Natural gas	9.8	9.0	11.0
Ecuador - crude oil	25.9	7.9	--
Other	11.3	17.6	17.2
Total	$473.1	448.7	384.6

Daily production rates and weighted average sales prices are shown on page 48.

Worldwide crude oil and liquids production averaged 57,015 barrels a day in 1995, 51,328 in 1994, and 34,311 in 1993. Crude oil and liquids production in the U.S. increased three percent in 1995, with production from new drilling more than offsetting normal reservoir depletion. In 1994, U.S. production was down three percent compared to 1993. Canadian production increased seven percent in the current year following a 69-percent increase in 1994. Production of heavy oil in Canada increased 30 percent in 1995 as a result of the continuation of an accelerated program to develop the Company's heavy oil reserves. In 1994, the program was deferred early in the year in response to weak crude oil prices, and production was down eight percent compared to 1993. The Company's acquisition of a five-percent interest in a synthetic crude oil project near the end of 1993 contributed 9,065 barrels a day to the increase in Canadian production in 1994. Murphy's average production from the U.K. increased 11 percent in 1995 after more than doubling in 1994. Production from Block 16/17 ("T" Block) in the North Sea, which commenced in November 1993, averaged 8,172 barrels a day in 1995 compared to 5,566 in 1994. Production from the Ninian field in the North Sea declined 14 percent in 1995 following a 36-percent increase in 1994. The increase in 1994 was due to the acquisition of an additional 3.82-percent interest in the field at the beginning of the year. Production in Ecuador, which commenced in June 1994, averaged 5,274 barrels a day in 1995 compared to 1,967 in 1994.

Worldwide sales of natural gas averaged 251.7 million cubic feet a day in 1995, 256.3 million in 1994, and 274.9 million in 1993. The three-percent decline in U.S. sales, most of which occurred in the last half of the year, was due to reduced deliverability in certain of the Company's larger fields. Natural gas sales were at record levels in Canada, increasing eight percent, and were up five percent in the U.K. Natural gas sales in Spain declined 14 percent in 1995 as sales from the Gaviota field ceased after the field was converted to a storage facility for third-party natural gas in the first quarter of the year. As a partial offset, sales from the Albatros field commenced in the second quarter of 1995. In 1994, the nine-percent decline in U.S. natural gas sales was primarily due to voluntary production curtailments in response to low sales prices, as normal production declines were nearly offset by incremental production from new fields placed on stream during 1993 and 1994. Natural gas sales in 1994 increased three percent in Canada and 32 percent in Spain, but declined 22 percent in the U.K., primarily as a result of contractual restrictions on the deliverability of the field.

As previously indicated, worldwide crude oil prices strengthened during 1995. In the U.S., Murphy's 1995 average monthly sales prices for crude oil and condensate ranged from $15.42 a barrel to $18.06, and averaged $16.61 for the year, an eight-percent increase over 1994. In Canada, the average sales price for light oil was $16.45 a barrel in 1995, an increase of 13 percent. Heavy oil prices were strong for much of 1995, but weakened late in the year and averaged $12.10 a barrel, up 15 percent from a year ago. The average sales price for synthetic crude oil was $17.28, up nine percent. U.K. sales prices averaged $16.96 in 1995, an increase of eight percent from a year ago. In 1994, average crude oil prices declined seven percent in the U.S. and five percent in the U.K. In Canada, average sales prices were down three percent for light oil, but up seven percent for heavy oil compared to 1993.

Average monthly natural gas sales prices in the U.S. ranged from $1.39 an MCF to $2.45 during 1995. For the year, prices averaged $1.64 an MCF compared to $1.91 a year ago. The average sales price for natural gas in Canada declined 32 percent. Prices increased four percent in the U.K. and 13 percent in Spain. Average natural gas sales prices in 1994 were down nine percent in the U.S. and three percent in Spain. Prices in Canada and the U.K. increased 16 percent and five percent, respectively.

Based on 1995 volumes and deducting taxes at marginal rates, each $1 a barrel and $.10 an MCF fluctuation in price would have affected annual exploration and production earnings by

$11.6 million and $5.9 million, respectively. Consolidated net income could have been affected differently because of contrary or corollary effects on other business segments.

Production costs were $167.5 million in 1995, $162.1 million in 1994, and $113.9 million in 1993. These amounts are shown by major operating area on pages 46 and 47. Costs per equivalent barrel of production during the last three years were as follows.

(Dollars per equivalent barrel)	1995	1994	1993
United States	$ 3.24	3.31	3.21
Canada			
Excluding			
synthetic oil	3.55	3.56	3.70
Synthetic oil	12.17	12.09	--
United Kingdom	5.88	5.77*	6.66*
Ecuador	6.01	8.21	--
Worldwide - excluding			
synthetic oil	3.90	3.94*	3.90*

*Reclassified to conform to 1995 presentation.

The increase in the cost per barrel for Canadian synthetic oil in 1995 was due to lower production volumes. Higher per equivalent barrel cost in the U.K. in 1995 was due to repairs to a Ninian production platform, while both 1995 and 1994 were favorably affected by higher production from "T" Block. The per-barrel cost in Ecuador decreased in 1995 due to higher production volumes. The 1994 increase in the U.S. was due primarily to lower production volumes resulting from curtailment of natural gas sales. The 1994 reduction in Canada, excluding synthetic oil, was due to strengthening of the U.S. dollar in relation to the Canadian dollar.

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 46 and 47. Certain of the expenses are included in the capital expenditure totals for exploration and production activities.

(Millions of dollars)	1995	1994	1993
Included in capital expenditures			
Dry hole costs	$30.9	16.6	21.5
Geological and			
geophysical costs	16.2	9.5	7.6
Other costs	8.0	5.6	4.9
	55.1	31.7	34.0
Undeveloped lease			
amortization	10.7	11.0	12.1
Total	$65.8	42.7	46.1

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Dry hole costs in 1995 included $21.5 million for an unsuccessful well drilled on Mobile Block 908 in the Gulf of Mexico.

Depreciation, depletion, and amortization related to exploration and production operations totaled $182.7 million in 1995, $161.5 million in 1994, and $139.7 million in 1993. The increases in 1995 and 1994 were primarily due to higher production volumes. The write-down of assets under SFAS No. 121, which was adopted effective October 1, 1995, resulted in a reduction in depreciation, depletion, and amortization in 1995 of $2.4 million ($2 million after tax).

REFINING, MARKETING, AND TRANSPORTATION - Earnings from refining, marketing, and transportation operations before unusual or infrequently occurring items were $2 million in 1995, $30.2 million in 1994, and $31.5 million in 1993. Operations in the U.S. lost $3.8 million in 1995 compared to earning $17.7 million in 1994. The 1995 loss included an after-tax provision of $3.9 million for estimated losses under crude oil swap agreements. U.S. operations earned $11.2 million in 1993. Operations in the U.K. earned $.3 million in 1995 compared to $5.2 million in 1994. In 1995, asset write-downs under SFAS No. 121 resulted in a reduction in depreciation, depletion and amortization of $1.5 million ($1 million after tax). U.K. operations earned $11.7 million in 1993. Canadian operations contributed $5.5 million to 1995 earnings compared to $7.3 million in 1994 and $8.6 million in 1993.

Unit margins (sales realizations less crude and other feedstocks, refining, and costs to point of delivery) averaged $.46 a barrel in the U.S. in 1995, $1.07 in 1994, and $.82 in 1993. U.S. product sales were up eight percent in 1995 following a slight decline in 1994. Margins in the Company's southeastern marketing area were under pressure throughout 1995, and for the year the average unit margin was down 68 percent compared to 1994. While benefiting from a strong asphalt market during the summer months, margins in the upper-midwestern area were also lower during much of 1995, and the average unit margin was down 44 percent from a year ago. Margins in both areas continued to be depressed at the end of 1995, and in early 1996 the Company was experiencing losses in its U.S. downstream operations. Compared to 1993, unit margins in the southeastern area were generally higher throughout most of 1994, while unit margins in the upper-midwestern area were down slightly.

Margins in the U.K. averaged $2.26 a barrel in 1995, $2.17 in 1994, and $3.08 in 1993. Sales of petroleum products declined 22 percent following a 24-percent increase in 1994. Most of the increase in 1994 related to low-margin cargo sales. Margins on sales through the Company's branded outlets were under pressure during 1995, as competition with supermarkets intensified. Losses were also being incurred in the U.K. in early 1996.

[GRAPH--EXPLORATION EXPENSES]

[GRAPH--AVERAGE SAWMILL MARGIN]

Margins fluctuated widely in 1994, but were generally below levels in 1993.

Based on sales volumes for 1995 and deducting taxes at marginal rates, each $.42 a barrel ($.01 a gallon) fluctuation in unit margins would have affected annual refining and marketing profits by $15.7 million. Consolidated net income could have been affected differently because of contrary or corollary effects on other business segments.

The declines in earnings from purchasing, transporting, and reselling crude oil in Canada in both 1995 and 1994 were due to lower crude trading volumes and margins even though pipeline throughputs were higher.

FARM, TIMBER, AND REAL ESTATE - Earnings from farm, timber, and real estate operations were $9 million in 1995, $17.5 million in 1994, and $13.1 million in 1993. Timber operations earned $8.7 million in 1995, down from $14.7 million in 1994. Earnings from the sale of pine sawtimber harvested from Company lands increased slightly in 1995, as a nine-percent increase in the average sales price more than offset a 12-percent decline in board feet harvested. Earnings from the Company's sawmills declined to near break-even levels in 1995, with a 12-percent decline in the average sales price for finished lumber more than offsetting a 2-percent increase in sales. The earnings contribution from real estate operations totaled $.5 million, down $1.4 million. Lot sales declined 46 percent. Farming operations were also at break-even levels in 1995 compared to earning $1.1 million in 1994. The improvement in 1994 earnings compared to 1993 was primarily from timber operations, a $3.4 million increase, and farming operations, a $1.2 million increase. Earnings from real estate operations declined $.5 million. Timber earnings were up as a result of an increase in sales of pine sawtimber and lumber and higher sales prices for each. The farms enjoyed favorable weather in 1994 compared to 1993. The decline in earnings from real estate operations was due to a decrease in lot sales.

CORPORATE - This segment includes interest income and expense and corporate overhead not allocated to operating functions. The increased loss in 1995 was due to higher interest expense. Lower interest income accounted for the increase in the loss in 1994 compared to 1993, which continued to benefit from interest earned on the investment of proceeds from sale of the Company's contract drilling business in 1992.

UNUSUAL OR INFREQUENTLY OCCURRING ITEMS - Net income for each of the three years ended December 31, 1995 included unusual or infrequently occurring items reviewed below. Where appropriate, pretax amounts are given, and if not separately stated therein, the affected components of the Consolidated Statements of Income are indicated. The information presented also indicates the quarter in which the item occurred. Certain other quarterly information is presented on page 28.

- Refund and settlement of income tax matters - A gain of $4.9 million for refund of U.S. income taxes was recorded in the third quarter of 1995. Gains of $3.2 million and $3.5 million were recorded in the third and fourth quarters, respectively, of 1995, for settlement of income tax matters in the U.K. A gain of $2 million for settlement of income tax matters in Gabon was recorded in the fourth quarter of 1995. A gain of $6.4 million for settlement of income tax matters in the U.K. was recorded in the second quarter of 1994. Gains of $11.3 million and $3.1 million were recorded in the first and fourth quarters, respectively, of 1993, for refund and settlement of income tax matters in the U.K.

- Impairment of long-lived assets - An after-tax provision of $168.4 million was recorded in the fourth quarter of 1995 for the write-down of assets determined to be impaired under provisions of SFAS No. 121 (see Note B to the consolidated financial statements).

- Provision for reduction-in-force - An after-tax provision of $4.2 million was recorded in the fourth quarter of 1995 for the cost of enhanced early retirement and severance programs.

- Adjustment of estimates for self-insured liabilities - An after-tax gain of $7 million was recorded in the first quarter of 1995 from an adjustment of amounts previously reserved relating to matters for which the Company is self-insured. The pretax amount of the gain, $11 million, was included in "Interest, Income from Equity Companies, and Other Nonoperating Revenues."

- Settlement of DOE matters - An after-tax gain of $13.9 million was recorded in the third quarter of 1994 upon settlement of a dispute with the U.S. Department of Energy (DOE) concerning the price at which the Company sold certain of its crude oil production under regulations in effect from September 1973 through January 1981. The pretax amount of the gain, $21 million, was included in "Interest, Income from Equity Companies, and Other Nonoperating Revenues" (see Note P to the consolidated financial statements).

- Provision for environmental remediation matters - An after-tax provision of $4 million was recorded in the fourth quarter of 1993 for environmental remediation matters. The pretax amount of $6.2 million was included in "Crude Oil, Products, and Related Operating Expenses."

- Cumulative effect of changes in accounting principles - The first quarter of 1993 included a net benefit of $15.3 million for the cumulative effect of accounting changes that were adopted effective January 1, 1993 (see Note B to the consolidated financial statements).

Excluding the cumulative effect of changes in accounting principles in 1993, the income (loss) effects of unusual or infrequently occurring items are summarized by segment in the following table for the three years ended December 31, 1995.

(Millions of dollars)	1995*	1994	1993
Exploration and production			
United States	$ (1.1)	--	--
United Kingdom	(18.4)	6.4	14.4
Other international	(100.6)	--	--
	(120.1)	6.4	14.4
Refining, marketing, and transportation			
United States	--	--	(3.9)
United Kingdom	(35.6)	--	(.1)
	(35.6)	--	(4.0)
Corporate	3.7	13.9	--
Total	$ (152.0)	20.3	10.4

* Includes after-tax effect of asset write-down under SFAS No. 121 as follows: exploration and production - U.S., $6; U.K., $24.2; other international, $102.6; refining, marketing, and transportation - U.K., $35.6.

Certain of the unusual or infrequently occurring items had a significant effect on the Company's consolidated effective income tax rates (see Note F to the consolidated financial statements).

CAPITAL EXPENDITURES

As shown in the selected financial information on page 20, capital expenditures were $296.3 million in 1995 compared to $397.3 million in 1994 and $620.7 million in 1993. These amounts included $55.1 million, $31.7 million, and $34 million of exploration expenditures that were expensed. Also included were $7.2 million in 1995, $26.6 million in 1994, and $259.7 million in 1993 for acquisition of proved oil and gas properties. Capital expenditures for exploration and production activities totaled $231.7 million in 1995, 78 percent of the Company's total capital expenditures for the year. Excluding acquisition of proved properties, exploration and production activities accounted for 76 percent of 1995 capital expenditures and totaled $224.5 million--$10.3 million for acquisition of undeveloped leases, $65.3 million for exploration activities, and $148.9 million for development projects. Development expenditures included $53.9 million for the Hibernia oil field, offshore Newfoundland, and $17.6 million for oil fields in Ecuador. The expenditures for acquisition of proved properties in 1995 included $4.2 million for heavy oil properties in Canada. Exploration and production capital expenditures are shown by major operating area on pages 46 and 47. Amounts shown under "Other" in 1995 include $4 million for exploration costs in China, including an unsuccessful well drilled on Block 04/36 in Bohai Bay; $2.2 million for exploration costs in Pakistan; and $2.1 million in Spain, primarily for development of the Albatros field.

Refining, marketing, and transportation expenditures, detailed in the following table, were $53.6 million in 1995, or 18 percent of total capital expenditures, compared to $94.7 million in 1994 and $86.9 million in 1993.

(Millions of dollars)	1995	1994	1993
Refining			
United States	$22.9	72.4	64.3
United Kingdom	17.9	2.1	2.1
Total refining	40.8	74.5	66.4
Marketing			
United States	4.6	6.8	6.9
United Kingdom	4.6	10.1	9.9
Canada	--	.1	.1
Total marketing	9.2	17.0	16.9

Transportation			
United States	.1	1.0	.2
Canada	3.5	2.2	3.4
Total transportation	3.6	3.2	3.6
Total	$53.6	94.7	86.9

Refining expenditures in the U.S. included $12.7 million for environmental projects, including wastewater treatment facilities at both of the Company's U.S. refineries and a new sulfur recovery unit at the Meraux, Louisiana, refinery, and $4.7 million for improved heavy, sour crude oil processing facilities at Meraux. Refining expenditures in the U.K. included $16.4 million for a distillate desulfurization unit under construction at year-end. Marketing expenditures included the costs of sites and new service stations and improvements and normal replacements at existing stations and terminals.

Capital expenditures for farm, timber, and real estate operations totaled $9.1 million in 1995 compared to $11.4 million in 1994 and $9.7 million in 1993. Expenditures in 1995 included $2.7 million for timber operations, primarily related to expansion of the Waldo sawmill, and $4.6 million for real estate operations.

[GRAPH--CAPITAL EXPENDITURES IN 1995]

CASH FLOWS

Cash provided by operating activities was $322.9 million in 1995, $337.3 million in 1994, and $363 million in 1993. Such amounts included cash provided from unusual or infrequently occurring items of $14.7 million in 1995, $5.3 million in 1994, and $11.8 million in 1993. Changes in operating working capital other than cash and cash equivalents required cash of $36.8 million in 1995 and $16.2 million in 1994. In 1993, those changes provided $.4 million of cash. Cash provided by operating activities was reduced by expenditures for refinery turnarounds and abandonment of oil and gas properties totaling $13.8 million in 1995, $55.3 million in 1994, and $13.4 million in 1993. Additional borrowings under nonrecourse debt arrangements provided $59.5 million of cash in 1995, $42.8 million in 1994, and $27.7 million in 1993. Other long-term borrowings also provided $28.2 million of cash in 1994.

Capital expenditures required $296.3 million of cash in 1995, $397.3 million in 1994, and $553.3 million in 1993. The 1993 amount excludes $67.4 million of noncash, seller-financed capital expenditures. Other significant cash outlays during the three years included $35.7 million in 1995 and $11.1 million in 1994 for reductions of debt. Cash used for dividends to stockholders was $58.3 million in 1995, $58.2 million in 1994, and $55.9 million in 1993. The Company also repurchased 48,400 shares of its Common Stock in 1993 for a cost of $1.6 million.

FINANCIAL CONDITION

Year-end working capital totaled $104.5 million in 1995, $79.6 million in 1994, and $130.2 million in 1993. The current level of working capital does not fully reflect the Company's liquidity position, as the relatively low historical costs assigned to inventories under LIFO accounting were $70 million below current costs at December 31, 1995. Cash and equivalents at the end of 1995 totaled $62.3 million compared to $71.1 million a year ago and $141.2 million at year-end 1993.

Long-term obligations increased $21.4 million and were $193.9 million at year-end, 15 percent of total capital employed, and included $171.5 million of nonrecourse debt incurred in connection with acquisition and development of proved properties. Long-term obligations totaled $172.5 million at the end of 1994 compared to $109.2 million at year-end 1993. Stockholders' equity was $1.1 billion at the end of 1995 compared to $1.3 billion a year ago and $1.2 billion at the end of 1993. The decrease in 1995 was primarily attributable to the asset write-down upon adoption of SFAS No. 121. A summary of transactions in the equity accounts is presented on page 33.

The primary sources of the Company's liquidity are internally generated funds, access to outside financing, and working capital. The Company 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. Current financing arrangements are set forth in Note D to the consolidated financial statements. The Company also had a shelf registration on file with the SEC that would permit the offer and sale of $250 million of debt securities. The Company does not anticipate any problem in meeting future requirements for funds.

The Company had commitments of $268 million for capital projects in progress at December 31, 1995.

ENVIRONMENTAL

The Company's worldwide operations are subject to numerous laws and regulations designed to protect the environment and/or impose remedial obligations. In addition, the Company may be involved in personal injury claims, allegedly caused by exposure to materials manufactured or used in the Company's operations. The Company operates or has previously operated certain sites or 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, liabilities for environmentally related obligations are recorded when such obligations are probable and the cost can be reasonably estimated. In instances where there is a range of reasonably estimated costs, the Company will record the most likely amount, or if no amount is most likely, the minimum of the range. Amounts recorded as liabilities are reviewed quarterly and adjusted as needed. Actual cash expenditures often occur a number of years after recognition of the liabilities.

The Company's reserve for remedial obligations, which is included in "Deferred Credits and Other Liabilities" in the Consolidated Balance Sheets, contains certain amounts that are based on anticipated regulatory approval of proposed remediation of sites that were formerly used for refinery waste. If regulatory authorities require more costly alternatives than the proposed processes, future expenditures could increase by up to an estimated $6 million above the amount reserved.

The Company has received notices from the U.S. Environmental Protection Agency that it is a Potentially Responsible Party (PRP) at five Superfund sites and has been assigned responsibility by defendants at another Superfund site. The potential total cost to all parties to perform necessary remedial work at these sites is substantial; however, based on information currently available, the Company

is a de minimis party, with assigned or potentially assigned responsibility of less than two percent at all but one of the sites. At that site, the Company has not determined either its potentially assigned responsibility percentage or its potential total remedial cost. The Company has recorded a reserve totaling $.1 million for Superfund sites, and due to currently available information on one site and the minor percentages involved on the other sites, the Company does not expect that its related remedial costs will be material to its financial condition. Additional information may become known in the future that would alter this assessment, including any requirement to bear a pro rata share of costs attributable to nonparticipating PRP's or indications of additional responsibility by the Company.

Although the Company is not aware of any environmental matters that might have a material effect on the Company's financial condition, there is the possibility that additional expenditures could be required at currently unidentified sites, and new or revised regulatory requirements could necessitate additional expenditures at known sites. Such expenditures could have a material impact on the results of operations in a future period.

The Company believes that certain liabilities for environmentally related obligations and prior environmental expenditures are either covered by insurance or will be recovered from other sources. The outcome of potential insurance recoveries is the subject of ongoing litigation, including the appeal of a judgment awarded the Company in 1995. Since no assurance can be given that the judgment will be upheld upon appeal or that recoveries from other sources will occur, the Company has not recognized a benefit for these potential recoveries at December 31, 1995.

The Company's refineries also incur costs to handle and dispose of hazardous wastes and other chemical substances on a recurring basis. These costs are generally expensed as incurred and amounted to $2.6 million in 1995.

In addition to remediation and other recurring expenditures, Murphy commits a significant amount of its capital expenditure program for compliance with environmental laws and regulations. Such capital expenditures were approximately $45 million in 1995 and are expected to be $35 million in 1996.

OTHER MATTERS

- Impact of Inflation - General inflation was moderate during the last three years in most countries where the Company operates; however, Murphy's revenues and costs do not necessarily correlate to changes in the general inflation rate. The Company's 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/demand balance in the near future. Natural gas prices are affected by supply and demand (which to a significant extent is weather-related) and by the fact that delivery of supplies is generally restricted to specific geographical areas. Lumber and farm commodities reflect the balance between supply and demand, while real estate sales respond to changes in the general economy and interest rates.

- Other - The effects of exchange rate fluctuations on net income and the Company's use of derivative financial instruments are reviewed in Notes G and L, respectively, to the consolidated financial statements.

  The Financial Accounting Standards Board issued Statement No. 123, Accounting for Stock-Based Compensation, in October 1995. The statement recommends use of a fair value method of accounting for stock-based employee compensation plans but allows for continued use of the Company's present accounting method established by Accounting Principles Board Opinion No. 25. The Company expects to continue its present method of accounting for such compensation but will be required by the new standard to make additional disclosures in future years of pro forma net income and earnings per share as if the new standard had been applied. The Company has not determined the pro forma effect for 1995.

OUTLOOK

In planning for 1996, prices for the Company's products remain uncertain. U.S. natural gas prices rose in late 1995 and early 1996; however, crude oil prices have retreated in early 1996, and would be under further pressure if an agreement were reached to remove the embargo on Iraqi crude oil sales. In addition, the Company's three downstream systems were incurring losses subsequent to year-end. In such an environment, constant reassessment of spending plans is required. The Company's capital expenditure budget for 1996 was prepared during the fall of 1995 and provides for expenditures of $416 million. A major portion of this amount, $324 million or 78 percent, is allocated for exploration and production. Geographically, about 33 percent of the exploration and production budget is designated for the U.S.; 30 percent for Canada, including $54 million for further development of the Hibernia oil field; 29 percent for the U.K., including development costs related to

the "T" Block, Schiehallion, and Mungo and Monan oil fields; four percent for further development of oil fields in Ecuador; and the remaining four percent for other overseas operations. Refining, marketing, and transportation capital expenditures for 1996 are budgeted at $76 million. Such amount includes $51 million for refining operations and $19 million for marketing facilities. Other budgeted expenditures include $14 million for farm, timber, and real estate, primarily related to real estate and the sawmills, and $2 million for miscellaneous items. Capital and other expenditures are under constant review, and these budgeted amounts may be adjusted to reflect changes in estimated cash flow.

QUARTERLY INFORMATION

(Millions of dollars except per share amounts)	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	YEAR
1995(1)					
Sales and other operating revenues(2)	$404.0	444.0	417.5	425.7	1,691.2
Income (loss)before income taxes	25.6	37.6	1.3	(198.5)	(134.0)
Net income (loss)	16.0	20.6	7.6	(162.8)	(118.6)
Per Common share					
Net income (loss)	.36	.46	.17	(3.63)	(2.64)
Dividends	.325	.325	.325	.325	1.30
Market Price					
High	45 3/8	44 3/8	42 3/8	42 1/2	45 3/8
Low	40 3/8	40 7/8	38 3/8	37 1/2	37 1/2
1994(1)					
Sales and other operating revenues(2)	$398.3	421.5	442.5	406.5	1,668.8
Income before income taxes	41.1	33.7	57.9	24.2	156.9
Net income	23.7	27.5	37.3	18.1	106.6
Per Common share					
Net income	.53	.61	.83	.40	2.37
Dividends	.325	.325	.325	.325	1.30
Market Price					
High	44 3/4	46	47 3/8	49 1/8	49 1/8
Low	37 7/8	40	42 1/8	40 1/2	37 7/8

1 The effects of unusual or infrequently occurring gains (losses) on quarterly net income are reviewed in Management's Discussion and Analysis. Quarterly totals, in millions of dollars, and the effect per Common share of these unusual or infrequently occurring items are reported in the following table.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
1995					
Quarterly totals	$7.0	--	8.1	(167.1)	(152.0)
Per Common share	.16	--	.18	(3.73)	(3.39)
1994					
Quarterly totals	$ --	6.4	13.9	--	20.3
Per Common share	--	.14	.31	--	.45

2 Each quarterly period in 1994 and the first three quarters of 1995 have been reclassified to conform to 1995 presentation.

Market prices of Common Stock are as quoted on the New York Stock Exchange. There were 4,873 stockholders of record at December 31, 1995.

REPORT OF MANAGEMENT

Preparation and integrity of the accompanying consolidated financial statements and other financial data are the responsibility of management. The statements were prepared in conformity with generally accepted 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 assurance (but not absolute) 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. Effectiveness of the controls is monitored by the Company's audit staff, which independently and systematically evaluates and formally reports on the adequacy and effectiveness of components of the system.

Our independent auditors, KPMG Peat Marwick LLP, have audited the consolidated financial statements. Their audit was conducted in accordance with generally accepted auditing standards and provides an independent opinion about the fair presentation of the consolidated financial statements. When performing their audit, KPMG Peat Marwick 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.

Annually the Board of Directors appoints an Audit Committee to perform an oversight role for the financial statements. 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 the Company's internal controls, the quality of its financial reporting, and the scope and results of audits. The independent auditors and the Company's audit staff have unrestricted access to the Committee, without management's presence, to discuss audit findings and other financial matters.

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Stockholders
Murphy Oil Corporation:

We have audited the accompanying consolidated balance sheets of Murphy Oil Corporation and Consolidated Subsidiaries as of December 31, 1995 and 1994, and the related consolidated statements of income, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 1995. 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 generally accepted auditing standards. 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, 1995 and 1994, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 1995, in conformity with generally accepted accounting principles.

As discussed in Note B to the consolidated financial statements, in 1995 the Company adopted the provisions of Financial Accounting Standards Board's Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of. In addition, in 1993 the Company adopted the provisions of Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, and Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes.

KPMG PEAT MARWICK LLP

Shreveport, Louisiana
March 1, 1996

CONSOLIDATED STATEMENTS OF INCOME

(Thousands of dollars except per share amounts)

Years Ended December 31	1995	1994*	1993*
REVENUES			
Sales	$1,646,053	1,620,847	1,572,849
Other operating revenues	45,189	47,975	52,813

Interest, income from equity companies, and other nonoperating revenues	19,971	30,341	16,514
Total revenues	1,711,213	1,699,163	1,642,176
COSTS AND EXPENSES			
Crude oil, products, and related operating expenses	1,274,780	1,231,497	1,220,397
Exploration expenses, including undeveloped lease amortization	65,755	42,741	46,071
Selling and general expenses	67,461	66,579	65,195
Depreciation, depletion, and amortization	225,924	198,885	174,686
Impairment of long-lived assets	198,988	--	--
Provision for reduction-in-force	6,610	--	--
Interest expense	14,737	12,403	7,614
Interest capitalized	(9,015)	(9,842)	(5,414)
Total costs and expenses	1,845,240	1,542,263	1,508,549
Income (loss) before income taxes	(134,027)	156,900	133,627
Federal and state income taxes (benefits)	(839)	37,536	40,383
Foreign income taxes (benefits)	(14,576)	12,736	6,446
Income (loss) before cumulative effect of changes in accounting principles	(118,612)	106,628	86,798
Cumulative effect of changes in accounting principles	--	--	15,338
NET INCOME (LOSS)	$ (118,612)	106,628	102,136
PER COMMON SHARE			
Income (loss) before cumulative effect of changes in accounting principles	$ (2.64)	2.37	1.94
Cumulative effect of changes in accounting principles	--	--	.34
Net income (loss)	$ (2.64)	2.37	2.28
Average Common shares outstanding	44,866,699	44,882,182	44,856,635

* Reclassified to conform to 1995 presentation.

See notes to consolidated financial statements, page 34.

CONSOLIDATED BALANCE SHEETS

(Thousands of dollars) December 31	1995	1994*
ASSETS		
Current assets		
Cash and cash equivalents	$ 62,284	71,144
Accounts receivable, less allowance for doubtful accounts of $5,863 in 1995 and $5,554 in 1994	234,816	244,241
Inventories		
Crude oil and raw materials	70,567	71,541
Finished products	64,996	44,890
Materials and supplies	40,239	36,000
Prepaid expenses	29,703	36,357
Deferred income taxes	17,514	14,939
Total current assets	520,119	519,112
Investments and noncurrent receivables	31,735	28,592
Property, plant, and equipment, at cost less accumulated depreciation, depletion, and amortization of $2,702,485 in 1995 and $2,342,421 in 1994	1,487,232	1,670,934
Deferred charges and other assets	80,027	93,394
	$ 2,119,113	2,312,032
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term obligations	$ 10,640	7,615
Accounts payable	299,189	309,795
Withholdings and collections due governmental agencies	35,603	35,090
Accrued insurance obligations	15,272	23,105
Other accrued liabilities	33,599	35,563
Income taxes	21,307	28,350
Total current liabilities	415,610	439,518
Notes payable and capitalized lease obligations	22,436	49,814
Nonrecourse debt of a subsidiary	171,499	122,638
Deferred income taxes	105,015	140,610
Reserve for dismantlement costs	144,893	138,894
Reserve for major repairs	11,417	3,244
Deferred credits and other liabilities	147,098	146,635
Stockholders' equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued	--	--
Common Stock, par $1.00, authorized 80,000,000 shares, issued 48,775,314 shares	48,775	48,775
Capital in excess of par value	507,758	507,797
Retained earnings	643,699	820,568
Currency translation adjustments	4,568	(2,403)
Unamortized restricted stock awards	(592)	(993)
Treasury stock	(103,063)	(103,065)

Total stockholders' equity	1,101,145	1,270,679
	$ 2,119,113	2,312,032

*Reclassified to conform to 1995 presentation.

See notes to consolidated financial statements, page 34.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of dollars) Years Ended December 31	1995	1994*	1993*
OPERATING ACTIVITIES			
Income (loss) before cumulative effect of changes in accounting principles	$(118,612)	106,628	86,798
Adjustments to reconcile above income (loss) to net cash provided by operating activities			
Depreciation, depletion, and amortization	225,924	198,885	174,686
Impairment of long-lived assets	198,988	--	--
Provisions for major repairs	25,375	22,571	17,679
Expenditures for major repairs and dismantlement costs	(13,820)	(55,284)	(13,391)
Exploratory expenditures charged against income	55,055	31,696	33,945
Amortization of undeveloped leases	10,700	11,045	12,126
Deferred and noncurrent income tax charges (credits)	(47,167)	21,328	36,970
Gains from disposition of assets	(3,140)	(1,575)	(1,474)
Other - net	18,257	1,102	16,270
(Increase) decrease in operating working capital other than cash and cash equivalents	(36,800)	(16,189)	418
Cumulative effect of accounting changes on working capital	--	--	25,437
Net recoveries (expenditures) on insurance claim to repair hurricane damage	7,619	14,673	(18,172)
Other adjustments related to operating activities	560	2,403	(8,319)
Net cash provided by operating activities	322,939	337,283	362,973
INVESTING ACTIVITIES			
Capital expenditures requiring cash	(296,284)	(397,324)	(553,309)
Proceeds from sale of property, plant, and equipment	8,408	5,506	5,721
Other - net	(10,375)	(17,546)	(14,396)
Net cash required by investing activities	(298,251)	(409,364)	(561,984)
FINANCING ACTIVITIES			
Additions to notes payable and capitalized lease obligations	751	28,248	161
Reductions of notes payable and capitalized lease obligations	(28,128)	(3,437)	(3,738)
Additions to nonrecourse debt of a subsidiary	59,489	42,793	27,693
Reduction of nonrecourse debt of a subsidiary	(7,604)	(7,614)	--
Decrease in short-term notes payable	--	--	(2,795)
Dividends paid	(58,257)	(58,232)	(55,945)
Purchase of Common Stock for treasury	--	--	(1,636)
Net cash provided (required) by financing activities	(33,749)	1,758	(36,260)
Effect of exchange rate changes on cash and cash equivalents	201	242	(1,349)
Net decrease in cash and cash equivalents	(8,860)	(70,081)	(236,620)
Cash and cash equivalents at January 1	71,144	141,225	377,845
CASH AND CASH EQUIVALENTS AT DECEMBER 31	$ 62,284	71,144	141,225

* Reclassified to conform to 1995 presentation.

See notes to consolidated financial statements, page 34.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(Thousands of dollars) Years Ended December 31	1995	1994	1993
CUMULATIVE PREFERRED STOCK - par $100, authorized 400,000 shares, none issued	$ --	--	--
COMMON STOCK - par $1.00, authorized 80,000,000 shares, issued 48,775,314 shares at beginning and end of year	48,775	48,775	48,775
CAPITAL IN EXCESS OF PAR VALUE			
Balance at beginning of year	507,797	507,292	506,962
Exercise and surrender of stock options	40	226	224

Restricted stock transactions	(79)	279	106
Capital in excess of par value at end of year	507,758	507,797	507,292
RETAINED EARNINGS			
Balance at beginning of year	820,568	772,172	725,981
Net income (loss) for the year	(118,612)	106,628	102,136
Cash dividends - $1.30 a share in 1995 and 1994 and $1.25 a share in 1993	(58,257)	(58,232)	(55,945)
Retained earnings at end of year	643,699	820,568	772,172
CURRENCY TRANSLATION ADJUSTMENTS			
Balance at beginning of year	(2,403)	(1,514)	21,595
Translation gains (losses) during the year	6,971	(889)	(23,109)
Currency translation adjustments at end of year	4,568	(2,403)	(1,514)
UNAMORTIZED RESTRICTED STOCK AWARDS			
Balance at beginning of year	(993)	(660)	(835)
Stock awards	--	(800)	--
Amortization, forfeitures, and changes in price of Common Stock	401	467	175
Unamortized restricted stock awards at end of year	(592)	(993)	(660)
TREASURY STOCK			
Balance at beginning of year	(103,065)	(103,715)	(102,390)
Cost of shares purchased	--	--	(1,636)
Exercise and surrender of stock options	67	308	360
Awarded restricted stock, net of forfeitures	(65)	342	(49)
Treasury stock at end of year - 3,942,800 shares of Common Stock in 1995, 3,942,868 shares in 1994, and 3,967,631 shares in 1993, at cost	(103,063)	(103,065)	(103,715)
TOTAL STOCKHOLDERS' EQUITY	$ 1,101,145	1,270,679	1,222,350

See notes to consolidated financial statements, page 34.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE A - SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation - The consolidated financial statements include the accounts of Murphy Oil Corporation and all majority-owned subsidiaries. Investments in 20- to 50-percent owned companies are accounted for by the equity method. Other investments are generally carried at cost. All significant intercompany accounts and transactions have been eliminated.

Cash Equivalents - Short-term investments (which include government securities or other securities with government securities as collateral) that have a maturity of three months or less from the date of purchase are classified as cash equivalents.

Inventories - Inventories of crude oil and refined products are generally valued at cost applied on a last-in, first-out (LIFO) basis, which in the aggregate is lower than market. Raw materials and lumber are stated at the lower of average cost or market. Materials and supplies are valued at the lower of average cost or estimated value.

Property, Plant, and Equipment - The Company uses the successful efforts method of accounting for exploration and development expenditures. Leasehold acquisition costs are capitalized. When proved reserves are found on an undeveloped property, leasehold cost is reclassified to proved properties. Significant undeveloped leases are reviewed periodically, and a valuation allowance is provided for any estimated decline in value. Cost of all other undeveloped leases is amortized over the estimated average holding period of the leases. Costs of exploratory drilling are initially capitalized, but if proved reserves are not found, the costs are subsequently expensed. All other exploratory costs are charged to expense as incurred. Development costs are capitalized, including the cost of unsuccessful development wells.

Effective October 1, 1995, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of. Under SFAS No. 121, oil and gas properties are evaluated by field for potential impairment; other long-lived assets are evaluated on a specific asset basis or in groups of similar assets, as applicable. An impairment is recognized when the undiscounted estimated future net cash flows of an evaluated asset are less than the carrying value of the asset. Previously, worldwide undiscounted future net cash flows for oil and gas properties were compared annually to net capitalized cost of proved properties to determine if an impairment had occurred. As warranted by events, significant, high-cost properties were assessed for permanent impairment based on discounted future net cash flows.

Depreciation and depletion of producing oil and gas properties are provided under the unit-of-production method. Developed reserves are used to compute unit rates for unamortized development costs, and proved reserves are used for unamortized leasehold costs. Estimated dismantlement, abandonment, and site restoration costs, net of salvage value, are considered in determining depreciation and depletion. Depreciation of refining and marketing facilities is calculated using the composite straight-line method. Depletion of timber is based on board feet cut. Other properties are depreciated by individual unit based 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. Costs of dismantling oil and gas production facilities and site restoration are charged against the related reserve. All other dispositions, retirements, or abandonments are reflected in accumulated depreciation, depletion, and amortization.

Provisions are made for refinery turnarounds by monthly charges to expense. Costs incurred are charged against the reserve. All other maintenance and repair costs are charged to expense. Renewals and betterments are capitalized.

Environmental Liabilities - A provision for environmentally related obligations is recorded by a charge to expense when it is determined that 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 reserve. Environmental expenditures that have future economic benefit are capitalized.

Income Taxes - The Company uses the asset and liability method of accounting for income taxes. Under this method, the provision for income taxes includes amounts currently payable and 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 and measured using the enacted tax rates that are assumed will be in effect when the differences reverse. Provision for petroleum revenue taxes payable to the U.K. government is based on the estimated effective tax rate over the life of certain U.K. properties.

Foreign Currency Translation - Local currency is the "functional currency" used for recording operations in Canada and Spain and the majority of activities in the U.K. and Gabon. The U.S. dollar is the functional currency used to record all other operations. Gains or losses that result from translating accounts from foreign functional currencies into U.S. dollars are included in "Currency Translation Adjustments" in stockholders' equity. Gains or losses that result from specific transactions in a currency other than the functional currency are included in income.

Derivatives - Unrealized gains and losses under oil swap and buy/sell agreements are deferred unless the projected cost of future crude oil purchases, including settlement costs, exceeds the projected realizable value of related finished products. Realized gains and losses are included in "Other Operating Revenues." Unrealized gains and losses related to foreign currency contracts are deferred and recognized in income or as adjustments to the carrying amounts when the hedged transactions occur.

Excise Taxes on Refined Products - Taxes collected on the sales of refined products and remitted to governmental agencies are not included in revenues or costs and expenses.

Net Income per Common Share - This amount is computed by dividing net income for each reporting period by the weighted average number of Common and Common equivalent (stock options when dilutive) shares outstanding during the period.

Use of Estimates - In the preparation of financial statements of the Company in conformity with generally accepted accounting principles, management has made a number of estimates and assumptions related to the reporting of assets and liabilities and the disclosure of contingent assets and liabilities. Actual results may differ from the estimates.

NOTE B - ACCOUNTING CHANGES - Effective October 1, 1995, the Company adopted SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of. The effects of this accounting change were a reduction in the carrying value of property, plant, and equipment by $198,988,000 and a $168,367,000, $3.75 a share, reduction of income after associated income tax benefit. The asset impairments resulted from management's expectation of a continuation into the foreseeable future of the low-price environment for crude oil, natural gas, and petroleum products that has confronted the oil and gas industry throughout most of 1995. The carrying values for assets determined to be impaired were adjusted to fair values based on estimated future net cash flows for such assets, discounted at a market rate of interest. Properties determined to be impaired were certain oil and gas assets (Ecuadoran fields; two fields in the U.K. North Sea; four U.S. fields, primarily in the Gulf of Mexico; and a property in Spain) and U.K. refining and marketing assets.

Effective January 1, 1993, the Company elected the immediate recognition basis for implementing SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions. This accounting standard requires that these costs (supplemental health care and life insurance) be accrued over the service lives of employees. The cumulative effect upon adoption was a charge against income of $16,502,000, $.37 a share, after an income tax effect of $8,500,000. Excluding the cumulative effect, adoption of the standard did not significantly affect 1993 net income.

Effective January 1, 1993, the Company also adopted SFAS No. 109, Accounting for Income Taxes, without restating prior years' results. The cumulative effect of the change on 1993 net income was a benefit of $31,840,000, $.71 a share. In addition, net property, plant, and equipment was increased $82,092,000, and a corresponding increase was recorded in deferred income tax liability, representing the tax effect of prior business combinations originally recorded net of tax. As a result of adopting SFAS No. 109, 1993 income before income taxes was reduced $10,916,000. This reduction was primarily due to increased depreciation, depletion, and amortization expense caused by the adjustment for prior business combinations. The increased expense was essentially offset by additional deferred tax benefits.

NOTE C - PROPERTY, PLANT, AND EQUIPMENT

(Thousands of dollars)	INVESTMENT DECEMBER 31, 1995		Investment December 31, 1994	
	COST	NET(1)	Cost	Net
Exploration and production	$3,163,843	975,801(3)	3,035,153(2)	1,123,954(2,3)
Refining	601,869	257,497	562,101	278,629
Marketing	160,234	92,734	156,501	104,832
Transportation	67,258	34,315	63,013	33,296
Farm, timber, and real estate	165,119	109,778	166,061	112,217
Corporate and other	31,394	17,107	30,526	18,006
	$4,189,717	1,487,232	4,013,355	1,670,934

1 As a result of adopting SFAS No. 121 effective October 1, 1995, net investment was reduced $150,301 for exploration and production, $37,085 for refining, and $11,602 for marketing.
2 Reclassified to conform to 1995 presentation.
3 Includes $17,239 in 1995 and $17,277 in 1994 related to administrative assets and support equipment.

The Company leases land, service stations, and other facilities under operating leases. Future minimum rental commitments under noncancelable operating leases are not material. Commitments for capital expenditures were approximately $268,000,000 at December 31, 1995.

NOTE D - FINANCING ARRANGEMENTS - At December 31, 1995, the Company had three committed credit facilities with major banks totaling an equivalent US $313,526,000 for a combination of U.S. dollar and Canadian dollar borrowings. Depending upon the credit facility, borrowings bear interest at prime or various cost of funds options. Facility fees are due at varying rates on certain of the commitments. The facilities expire at dates ranging from 1996 through 1999. At December 31, 1995, U.S. dollar and Canadian dollar commercial paper totaling an equivalent US $110,296,000, classified as long-term nonrecourse debt, was outstanding under one credit facility. At December 31, 1994, outstanding debt supported by two facilities totaled US $97,862,000, of which $69,862,000 was classified as long-term nonrecourse debt of a subsidiary and $28,000,000 as long-term notes payable. In addition, the Company had lines of credit with banks totaling an equivalent US $160,521,000 for a combination of U.S. dollar and Canadian dollar borrowings. These lines could be withdrawn at any time, and no amounts were outstanding at December 31, 1995.

At year-end 1995, the Company had a shelf registration on file with the Securities and Exchange Commission that would permit the offer and sale of $250,000,000 in debt securities. No securities had been issued as of December 31, 1995.

NOTE E - LONG-TERM OBLIGATIONS

(Thousands of dollars)

December 31	1995	1994
Notes payable		
Note payable to bank, 10.1%, due 2004	$ 20,000	20,000
Notes payable to bank, 6.3125%* to 6.75%*, due 1999	--	28,000
Other notes due 1996-2000	797	170
Subtotal	20,797	48,170
Capitalized lease obligations due 1996-2022; 6%, 8%	1,651	1,655
Nonrecourse debt of a subsidiary		
Guaranteed credit facility with bank		
Commercial paper, 5.655% to 5.855%, $40,896 payable in Canadian dollars, supported by credit facility, due 1997	110,296	--
Credit facility drawdown from bank, 6.1875% to 7.455%, due 1996	--	69,862
Loan payable to Canadian government, interest free, due 1999-2008, payable in Canadian dollars	19,055	--
Promissory note, 6.25%, due 1996-1998, payable in Canadian dollars	52,776	60,380
Subtotal	182,127	130,242
Total	204,575	180,067
Current maturities	(10,640)	(7,615)
Total long-term obligations	$ 193,935	172,452

* Interest rates fluctuate in relation to bank's cost of funds.

Amounts becoming due for the four years after 1996 are: 1997, $13,644,000; 1998, $28,530,000; 1999, $2,670,000; and 2000, $1,921,000.

The nonrecourse guaranteed credit facility was arranged to finance expenditures for the Hibernia oil field, in which the Company owns a 6.5-percent interest. Subject to certain conditions and limitations, the Canadian government has provided an unconditional guarantee of repayment of amounts drawn under/supported by the credit facility to lenders that possess qualifying Participation Certificates. The Company's maximum eligible borrowing available under the guarantee is Cdn $154,900,000 (US $113,526,000 at December 31, 1995 currency exchange rate). The Company also received other commitments from the Canadian government, including grants and additional guarantees and interest-free loans. The amount guaranteed declines quarterly beginning the earlier of January 1, 2000 or two years after cumulative production reaches 25 million barrels; no guaranteed financing is available after January 1, 2016. A guarantee fee of .5 percent is payable annually in arrears to the Canadian government. Since the Company intends to refinance outstanding debt under the guaranteed credit facility, the debt is not reflected as becoming due in 1997.

The 6.25-percent promissory note of Cdn $69,970,000 (US $52,776,000 at a hedged exchange rate) is payable to the province of Alberta and is secured by a debenture, which mortgages the Company's five-percent interest in the Syncrude project and its share of production therefrom. The province's right to recover the principal and interest on the note is limited to the mortgaged property and funds available from that production.

NOTE F - INCOME TAXES - The Company adopted SFAS No. 109, Accounting for Income Taxes, effective January 1, 1993 without restating prior years. Total income tax expense of $38,329,000 for 1993 included $46,829,000 allocated to income before income taxes, partially offset by a benefit of $8,500,000 allocated to the cumulative effect of a change in accounting for postretirement benefits.

The components of income (loss) before income taxes and income tax expense (benefit) were as follows.

(Thousands of dollars)	1995	1994	1993
Income (loss) before income taxes			
United States	$ 9,127	105,695	84,563
Foreign	(143,154)	51,205	49,064
	$(134,027)	156,900	133,627
Income tax expense (benefit)			
Federal - Current*	$ 10,248	6,010	29,941
Deferred	(21,030)	23,682	97
Noncurrent	9,008	3,708	4,977
	(1,774)	33,400	35,015
State - Current	935	4,136	5,368
Foreign - Current	22,929	15,398	(32,029)
Deferred	(19,580)	183	28,154
Noncurrent	(17,925)	(2,845)	10,321
	(14,576)	12,736	6,446
	$ (15,415)	50,272	46,829

* Net of benefits of $4,273 in 1995, $1,923 in 1994, and $5,757 in 1993 for alternative minimum tax credit and $8,079 in 1993 for net operating loss carryforward.

Noncurrent taxes relate to petroleum revenue taxes payable to the U.K. government ($6,330,000 and $24,461,000 at December 31, 1995 and 1994 and classified in the Consolidated Balance Sheet as "Deferred Credits and Other Liabilities") and to matters not resolved with various taxing authorities. The significant components of deferred income tax expense (benefit) attributable to income (loss) before income taxes for the years ended December 31, 1995, 1994, and 1993 were as follows.

(Thousands of dollars)	1995	1994	1993
Deferred tax expense (exclusive of the effects of components listed below on deferred tax assets and liabilities at the beginning of each year)	$(36,283)	23,883	18,270
Adjustments for enacted changes in tax laws and rates	--	--	190
Estimated net operating loss and tax credit carryforward (increase) decrease	(4,327)	(18)	9,791
Total deferred tax expense (benefit)	$(40,610)	23,865	28,251

Following is a reconciliation of the U.S. statutory income tax rate to the Company's effective rates on income (loss) before income taxes.

	1995	1994	1993
U.S. statutory income tax rate	(35)%	35%	35%
Foreign asset impairment with no tax benefit	27	--	--
Foreign income subject to foreign taxes at greater than U.S. statutory rate	7	2	7
Refund and settlement of foreign tax matters	(6)	(4)	(11)
Refund and settlement of U.S. tax matters	(6)	(2)	--
State income taxes	1	2	3
Other, net	--	(1)	1
Effective income tax rates	(12)%	32%	35%

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 1995 and 1994 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	1995	1994
Deferred tax assets		
Property and leasehold costs	$ 60,540	64,700
Reserves for dismantlement costs and major repairs	52,766	47,372
Federal alternative minimum tax credit carryforward*	8,243	3,916
Postretirement and other employee benefits	18,686	16,902
Other deferred tax assets	30,413	34,237
Total gross deferred tax assets	170,648	167,127
Less valuation allowance	(34,597)	(39,315)
Net deferred tax assets	136,051	127,812
Deferred tax liabilities		
Property, plant, and equipment	(49,071)	(56,689)
Accumulated depreciation, depletion, and amortization	(149,503)	(167,388)
Other deferred tax liabilities	(25,391)	(29,685)
Total gross deferred tax liabilities	(223,965)	(253,762)
Net deferred tax liabilities	$ (87,914)	(125,950)

* Available to reduce future U.S. federal income taxes over an indefinite period.

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 decreased $4,718,000 in 1995 after increasing

$6,235,000 in 1994; the change in each year offset the change in certain deferred tax assets. Any subsequent reductions of the valuation allowance will be reported as reductions of income tax expense assuming no offsetting change in the deferred tax asset.

The Company has not recorded a deferred tax liability of $7,809,000 related to undistributed earnings of certain foreign subsidiaries at December 31, 1995, because the earnings are considered permanently invested.

Income tax returns are subject to audit by the Internal Revenue Service and tax authorities of other countries. In 1995, 1994, and 1993, the Company recorded benefits to income of $13,603,000, $6,365,000, and $14,409,000, respectively, from settlement of various U.S. and foreign tax issues related to prior years. The Company believes that adequate accruals have been made for unsettled issues.

NOTE G - CURRENCY TRANSLATION - Cumulative translation gains and losses are included as a separate component of stockholders' equity. At December 31, 1995, components of the net cumulative gain of $4,568,000 were gains of $22,381,000 for pounds sterling, $1,470,000 for Spanish pesetas, and $314,000 for Gabonese francs, partially offset by a loss of $19,597,000 for Canadian dollars. Most of the amounts translated into U.S. dollars are from transactions denominated in pounds sterling or Canadian dollars. Comparability of net income was not significantly affected in 1995, 1994, or 1993 by exchange rate fluctuations.

NOTE H - STOCKHOLDER RIGHTS PLAN - The Company has a Stockholder Rights Plan, which 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 December 6, 1999, unless earlier redeemed or exchanged. The Rights will detach from the Common Stock and become exercisable following a specified period of time, subject to extension, after the date of 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 percent 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 between the Company and Harris Trust Company of New York, as Rights Agent.

NOTE I - INCENTIVE PLANS - At December 31, 1995, the Company had a Stock Incentive Plan, approved by the stockholders in 1992, that permits annual awards of shares of the Company's Common Stock to executives and other key employees. Under the Plan, the Executive Compensation Committee (the Committee) is authorized to grant: (1) stock options (nonqualified or incentive), (2) stock appreciation rights (SAR), and (3) restricted stock awards. Options for 94,855 shares were outstanding at December 31, 1995 under two prior plans that have expired.

Changes in options outstanding under the Company's plans, excluding restricted stock awards, were as follows.

	Number of Shares	Average Price
Outstanding January 1, 1993	341,036	$35.87
Granted	81,000	36.31
Surrendered	(45,019)	29.58
Outstanding December 31, 1993	377,017	36.72
Granted	69,500	39.94
Surrendered	(54,950)	34.86
Expired	(51,837)	41.18
Outstanding December 31, 1994	339,730	37.00
Granted	142,000	43.94
Surrendered	(33,250)	35.86
Expired	(23,250)	39.20
Outstanding December 31, 1995	425,230	39.28
Exercisable December 31, 1994	147,480	$36.32
Exercisable December 31, 1995	198,355	36.31

Cost of options reported in the preceding table is accrued over the vesting periods and adjusted for subsequent changes in fair market value of the shares. Charges against (credits to) income were $(163,000) in 1995, $1,024,000 in 1994, and $1,190,000 in 1993.

Through December 31, 1995, 52,000 restricted shares have been awarded and 13,989 shares have been forfeited, leaving 38,011 shares outstanding. Costs of restricted stock charged against income were $385,000 in 1995, $433,000 in 1994, and $347,000 in 1993.

In addition to the above plans, the Company has an Incentive Compensation Plan that provides for annual cash awards to officers, directors, and key employees based on actual results for a year compared to measurable financial performance objectives established at the beginning of that year. The Plan is administered by the Committee. Provisions of $400,000, $1,200,000, and $1,732,000 were recorded in 1995, 1994, and 1993, respectively, in anticipation of future awards.

NOTE J - EMPLOYEE AND RETIREE BENEFITS

Retirement Plans - The Company has defined benefit retirement plans that cover substantially all employees. Benefits are based on years of service and final-pay or career-average-pay formulas as defined by the plans. All plans are noncontributory. The Company also has a nonqualified supplemental plan for directors and supplemental plans that provide benefits to employees whose defined benefits under their retirement plan formula cannot be fully funded because of statutory limitations on the amount of benefits that may be paid from qualified plans. As part of a reduction-in-force

program, special termination benefits were offered certain U.S. employees in 1995; a curtailment gain resulted from a reduction in future service cost for employees accepting the offer.

Retirement expense (expense reduction) and its components for 1995, 1994, and 1993 are shown in the following tables.

U.S. Plans

(Thousands of dollars)	1995	1994	1993
Service cost - benefits earned during the year	$ 3,266	3,736	3,780
Interest accrued on benefits earned in prior years	10,984	10,465	10,295
Actual return on plan assets	(32,876)	(3,761)	(8,564)
Net amortization and deferral	18,456	(10,900)	(6,402)
Retirement expense reduction*	(170)	(460)	(891)
Special termination benefits	7,005	-	1,316
Curtailment gain	(2,494)	-	-
Net retirement expense (expense reduction)	$ 4,341	(460)	425

* Major assumptions were discount rates of 7.50% for 1995 and 6.75% for 1994 and 1993; assumed long-term rate of return on plan assets was 8.50% for 1995, 1994, and 1993.

Non-U.S. Plans

(Thousands of dollars)	1995	1994	1993
Service cost - benefits earned during the year	$ 1,482	1,537	1,478
Interest accrued on benefits earned in prior years	2,173	2,404	2,326
Actual return on plan assets	(3,652)	(894)	(4,466)
Net amortization and deferral	811	(2,323)	1,463
Retirement expense*	$ 814	724	801

* Major assumptions were discount rates of 7.50%-9.50% in 1995, 6.50%-7.50% in 1994, and 7.50%-8.50% in 1993; assumed long-term rates of return on plan assets were 7.50%-9.50% in 1995, 6.50%-7.50% in 1994, and 7.50%-8.50% in 1993.

Amounts contributed to U.S. funded plans are actuarially determined and are at least the minimum required by the Employee Retirement Income Security Act of 1974. Amounts contributed to non-U.S. plans are based on local laws. The supplemental plans are unfunded, and accumulated benefits exceeded assets in one funded plan in 1995 and 1994. Accumulated benefits in excess of assets in these plans were $5,906,000 in 1995 and $5,916,000 in 1994; these amounts have been netted in the following table, which sets forth the combined funded status of plans and amounts recognized in the Consolidated Balance Sheets.

	U.S. Plans		Non-U.S. Plans	
(Thousands of dollars)	1995	1994	1995	1994
Present value of accumulated benefits based on years of service, applicable pay formula, and present pay levels				
Vested	$ 142,238	124,154	24,060	26,104
Nonvested	7,023	4,890	188	164
Accumulated benefit obligation(1)	149,261	129,044	24,248	26,268
Provision for future pay increases	17,514	19,569	6,645	5,677

Projected benefit obligation(1)	166,775	148,613	30,893	31,945
Plan assets - at market value(2)	181,791	158,540	38,574	34,495
Plan assets in excess of projected benefit obligation	15,016	9,927	7,681	2,550
Unrecognized net asset from transition to SFAS No. 87(3)	(15,667)	(17,668)	(2,268)	(2,521)
Unrecognized net loss (gain) from unfavorable (favorable) actuarial experience	7,302	18,908	(11,417)	(5,102)
Unrecognized prior service cost	1,861	2,152	2,655	2,864
Additional minimum liability	(474)	(1,658)	--	--
Prepaid (accrued) retirement cost	$ 8,038	11,661	(3,349)	(2,209)

1 Major assumptions for U.S. plans were discount rates of 7.00% for 1995 and 7.50% for 1994 and future pay rate increases of 4.60% for 1995 and 5.00% for 1994. Major assumptions for non-U.S. plans were discount rates of 7.50%-9.50% for 1995 and 6.50%-9.50% for 1994 and future pay rate increases of 6.00%-7.00% for 1995 and 1994.

2 Primarily includes listed stocks and bonds, government securities, U.S. agency bonds, corporate bonds, and group annuity contracts.

3 Being amortized over periods of 14 to 19.2 years.

Thrift Plans - Most employees of the Company in the U.S. and Canada may participate in thrift 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 length of participation in the plans. Company contributions to these plans were $2,952,000 in 1995, $2,707,000 in 1994, and $2,631,000 in 1993.

Postretirement Benefits - In the U.S., the Company sponsors plans that provide comprehensive health care benefits (supplementing Medicare benefits for those eligible) and life insurance benefits for most retired employees. Costs are accrued for these plans during the service lives of covered employees. Retirees contribute the same amounts to the self-funded cost of health care benefits as do active employees; the Company contributes the remainder. The Company pays

premiums for life insurance coverage, arranged through an insurance company. The health care plan is funded on a pay-as-you-go basis. The Company has the right to modify the benefits and/or cost-sharing provisions.

Based on actuarial computations, postretirement expense and its components for 1995, 1994, and 1993 are shown below.

(Thousands of dollars)	1995	1994	1993
Service cost	$ 548	895	604
Amortization of net actuarial loss	476	347	--
Interest cost	2,706	2,733	2,250
Postretirement expense	$3,730	3,975	2,854

A summary follows of the postretirement benefit obligations recorded in the Consolidated Balance Sheets at December 31, 1995 and 1994, classified as "Deferred Credits and Other Liabilities." Calculation of the amount of accumulated unfunded postretirement benefit obligations (APBO) was based on discount rates of 7.00 percent and 7.75 percent in 1995 and 1994.

(Thousands of dollars)	1995	1994
APBO		
Retirees	$ 27,595	26,173
Fully eligible active participants	2,443	2,790
Other active participants	8,622	10,904
Total unfunded APBO	38,660	39,867
Unrecognized net actuarial loss	(7,765)	(11,229)
Accrued APBO obligations	$ 30,895	28,638

In determining the APBO at December 31, 1995, health care inflation cost was assumed to increase at an annual rate of 8.5 percent, gradually decreasing to 4.5 percent in 2002 and thereafter. An increase of one percent in the assumed health care cost trend would increase both the 1995 postretirement benefit expense and the APBO at December 31, 1995 by 13.9 percent.

NOTE K - SUPPLEMENTAL CASH FLOWS DISCLOSURES - Cash income taxes paid, net of refunds, were $24,638,000, $29,999,000, and $14,802,000 in 1995, 1994, and 1993. Interest paid, net of amounts capitalized, was $5,434,000, $1,873,000, and $1,575,000 in 1995, 1994, and 1993. A noncash investing and financing activity excluded from the Consolidated Statements of Cash Flows was the assumption of $67,370,000 of nonrecourse debt in 1993 upon acquisition of a five-percent interest in the Syncrude project.

(Increases) decreases in noncash operating working capital for each of the three years ended December 31, 1995 were:

(Thousands of dollars)	1995	1994	1993
Accounts receivable	$ 9,425	(48,027)	45,183
Inventories	(23,371)	(408)	(15,166)
Prepaid expenses	6,654	(1,315)	7,467
Deferred income tax assets	(2,575)	3,558	(18,497)
Accounts payable and accrued liabilities ...	(19,890)	30,947	(5,922)
Current income tax liabilities	(7,043)	(944)	(12,647)
	$(36,800)	(16,189)	418

NOTE L - DERIVATIVE FINANCIAL INSTRUMENTS - The Company utilizes derivative transactions on a limited basis to manage well-defined risks related to commodity prices and foreign currency exchange rates. The Company does not hold any derivatives for trading purposes.

Occasionally the Company uses derivative agreements to reduce the financial exposure of its U.S. refinery operations to unfavorable market movements related to crude oil inventories and/or anticipated crude oil purchases. Under each agreement, the Company receives or pays a cash settlement at maturity based on the differential between the agreement price and an agreed future crude oil price. At December 31, 1995, the Company had swap agreements for 4,000,000 barrels. Maturity dates of these agreements range from the third quarter of 1996 to the third quarter of 1997. Estimated settlement costs under the agreements using December 31, 1995 oil prices exceeded projected revenues by $7,965,000, which is fully reserved in the 1995 Consolidated Balance Sheet.

The Company has foreign exchange contracts to manage certain foreign exchange risks. At December 31, 1995, the Company had hedging contracts to buy Cdn $69,970,000, fixing the U.S. dollar costs for certain Canadian dollar nonrecourse debt. The Company also had a hedging contract to sell US $7,600,000, fixing the Canadian dollar revenues from the sale of Canadian crude in U.S. dollars.

NOTE M - FAIR VALUE OF FINANCIAL INSTRUMENTS - The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 1995 and 1994. 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, trade accounts payable, and accrued expenses, all of which had fair values approximating carrying values.

	1995		1994	
(Thousands of dollars)	Carrying or Notional Amount	Estimated Fair Value	Carrying or Notional Amount	Estimated Fair Value
Financial assets				
Investments and noncurrent receivables	$ 10,575	10,575	10,625	10,625
Financial liabilities				
Long-term obligations including current maturities	(204,575)	(200,127)	(180,067)	(178,355)
Payables (derivatives) ..	(9,142)	(7,965)	(1,368)	(4,828)

Off-balance-sheet exposures				
Financial guarantees and letters of credit	(41,681)	(41,681)	(45,164)	(45,164)

The carrying amounts of financial assets and financial liabilities shown in the preceding table are included in the Consolidated Balance Sheets under the indicated captions. The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value.

- Investments and noncurrent receivables - Investments in real estate held for sale and investments carried on an equity basis are excluded from the table. The carrying value of the remainder approximates fair value.

- Long-term obligations including current maturities - The fair value is estimated based on current rates offered the Company for debt of the same maturities.

- Payables (derivatives) - The amounts relate to the Company's oil swap and buy/sell agreements. The negative fair value is an estimate of the amount, which is based on quotes from brokers, that the Company would be required to pay at the reporting date to cancel the agreements.

- Financial guarantees and letters of credit - The fair value is based on the estimated cost to settle these obligations.

NOTE N - CONCENTRATION OF CREDIT RISKS - The Company's primary credit risk is from trade accounts receivable. These receivables arise mainly from sales of crude oil, natural gas, and petroleum products to a large number of customers in the U.S., Canada, and the U.K. The credit history and financial condition of potential customers are reviewed before credit is extended, security may be obtained then or later, routine follow-up evaluations are made, and an allowance for doubtful accounts is maintained, generally based upon a risk evaluation of specific customers. The Company also has certain off-balance-sheet financial instruments (see Note M to the consolidated financial statements); the Company controls the credit risks on these instruments through credit approvals and monitoring procedures and believes such risks are minimal. Historically, the Company has not incurred any significant credit-related losses, and at December 31, 1995, the Company had no significant concentration of credit risk outside the oil and gas industry.

NOTE O - OTHER FINANCIAL INFORMATION - Inventories valued at cost under the LIFO method totaled $94,779,000 and $90,515,000 at December 31, 1995 and 1994, respectively. These amounts were $70,040,000 and $57,389,000, respectively, less than such inventories would have been valued using the FIFO method. Net gains from foreign currency transactions were $82,000 in 1995, $51,000 in 1994, and $10,000 in 1993.

NOTE P - CONTINGENCIES - The Company's operations and earnings have been and may be affected by various forms of governmental action both in the U.S. and throughout the world. Examples of such governmental action include, but are by no means limited to: tax increases and retroactive tax claims; restrictions on production; 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 issuance of oil and gas or mineral leases; laws and regulations intended for the protection and/or remediation of the environment; promotion of safety; 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.

DOE Matters - In 1994 the Company and the U.S. Department of Energy (DOE) entered into a Consent Order that settled the last remaining issues related to DOE regulations that were in effect from 1973 through 1981. The settlement resulted in a $21,034,000 benefit ($13,871,000 after tax), which was recorded in "Interest, Income from Equity Companies, and Other Nonoperating Revenues" in the Consolidated Statement of Income for 1994.

Environmental Matters - The Company's environmental contingencies are reviewed in Management's Discussion and Analysis under the section entitled "Environmental" on page 26.

Other Matters - The Company and its subsidiaries are engaged in a number of other legal proceedings, all of which the Company considers routine and incidental to its business and none of which is material as defined. In the normal course of its business activities, the Company is required under certain contracts with various governmental authorities and others to provide letters of credit that may be drawn upon if the Company fails to perform under those contracts. At December 31, 1995, the Company had contingent liabilities of $23,992,000 on outstanding letters of credit. Contingent liabilities under certain guaranty agreements totaled $17,689,000 at December 31, 1995.

NOTE Q - BUSINESS SEGMENTS - Information about business segments and geographic operations is summarized in the following tables. Excise taxes on petroleum products of $521,250,000, $524,464,000, and $391,177,000 for the years 1995, 1994, and 1993 were excluded from revenues and costs and expenses. Intracompany and affiliated company transfers are at market prices. Companies accounted for by the equity method are primarily engaged in the transportation of crude oil and petroleum products.

(Thousands of dollars)	1995	1994*	1993*
REVENUES FOR THE YEAR			
Petroleum			
Exploration and production			
United States	$ 205,604	215,533	253,257
Canada	139,133	127,122	71,447
United Kingdom	110,789	90,312	51,590
Other international	37,981	24,765	16,606
	493,507	457,732	392,900
Refining, marketing, and transportation			
United States	1,010,967	908,705	950,907
Canada	22,589	26,885	29,601
United Kingdom	254,746	306,297	274,898
	1,288,302	1,241,887	1,255,406
	1,781,809	1,699,619	1,648,306
Intrasegment transfers elimination	(169,309)	(118,657)	(92,025)
Total petroleum	1,612,500	1,580,962	1,556,281
Farm, timber, and real estate - United States	78,742	87,860	69,381
Corporate and other	19,971	30,341	16,514
	$1,711,213	1,699,163	1,642,176

*Reclassified to conform to 1995 presentation.

(Thousands of dollars)	1995(1)	1994	1993(2)
OPERATING INCOME (LOSS) FOR THE YEAR			
Petroleum			
Exploration and production	$ (97,583)	68,386	68,637
Refining, marketing, and transportation	(42,670)	50,642	45,539
Total petroleum	(140,253)	119,028	114,176
Farm, timber, and real estate	14,387	28,710	21,170
Operating income (loss)	(125,866)	147,738	135,346
Nonoperating (charges) credits			
Income of equity companies	1,348	1,129	973
Income taxes	15,415	(50,272)	(46,829)
Corporate and other revenues (expenses) - net	(9,509)	8,033	(2,692)
Cumulative effect of accounting			

changes	--	--	15,338
Net income (loss)	$ (118,612)	106,628	102,136
NET INCOME (LOSS) FOR THE YEAR			
Petroleum			
Exploration and production			
United States	$ 3,755	18,128	32,701
Canada	21,669	15,097	6,304
United Kingdom	(11,934)	12,409	17,931
Other international	(104,075)	5,984	(5,666)
	(90,585)	51,618	51,270
Refining, marketing, and transportation			
United States	(3,767)	17,674	7,246
Canada	5,544	7,298	8,628
United Kingdom	(35,294)	5,231	11,625
	(33,517)	30,203	27,499
Total petroleum	(124,102)	81,821	78,769
Farm, timber, and real estate - United States	9,005	17,470	13,154
Corporate and other	(3,515)	7,337	(5,125)
Income (loss) before cumulative effect of accounting changes	(118,612)	106,628	86,798
Cumulative effect of accounting changes	--	--	15,338
	$ (118,612)	106,628	102,136
ASSETS AT YEAR-END			
Petroleum			
Exploration and production			
United States	$ 317,422	386,830	461,087
Canada	502,830	415,318	343,880
United Kingdom	248,493	320,143	306,248
Other international	80,688	170,111	111,903
	1,149,433	1,292,402	1,223,118
Refining, marketing, and transportation			
United States	494,577	500,467	378,405
Canada	56,786	55,578	63,353
United Kingdom	128,952	156,884	147,444
	680,315	712,929	589,202
Total petroleum	1,829,748	2,005,331	1,812,320
Farm, timber, and real estate - United States	163,834	155,583	150,261
Corporate and other	125,531	151,118	206,278
	$ 2,119,113	2,312,032	2,168,859
ADDITIONS TO PROPERTY, PLANT, AND EQUIPMENT FOR THE YEAR(3)			
Petroleum			
Exploration and production			
United States	$ 36,064	59,847	71,883
Canada	93,612	105,355	172,838
United Kingdom	27,527	29,063	173,392
Other international	19,460	60,387	68,028
	176,663	254,652	486,141
Refining, marketing, and transportation			
United States	27,565	80,272	71,363
Canada	3,561	2,234	3,474
United Kingdom	22,476	12,191	12,048
	53,602	94,697	86,885
Total petroleum	230,265	349,349	573,026
Farm, timber, and real estate - United States	9,133	11,403	9,674
Corporate and other	1,831	4,876	4,034
	$ 241,229	365,628	586,734
DEPRECIATION, DEPLETION, AND AMORTIZATION EXPENSE FOR THE YEAR(3)			
Petroleum			
Exploration and production			
United States	$ 89,669	93,057	97,196
Canada	26,707	25,088	21,062
United Kingdom	50,426	38,601	16,749
Other international	15,923	4,754	4,651
	182,725	161,500	139,658
Refining, marketing, and transportation			
United States	25,862	19,928	20,144
Canada	1,549	1,573	1,466
United Kingdom	9,062	9,589	8,562
	36,473	31,090	30,172
Total petroleum	219,198	192,590	169,830
Farm, timber, and real estate - United States	4,053	3,886	3,488
Corporate and other	2,673	2,409	1,368

	$ 225,924	198,885	174,686

1 As set forth in Note B to the consolidated financial statements, the effects from adoption of SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of, were:
Operating income (loss) - a loss of $198,988, $150,301 related to the exploration and production segment and $48,687 to refining, marketing, and transportation.
Net income (loss) - a loss of $168,367, $132,798 related to the exploration and production segment ($5,986 United States, $24,197 United Kingdom, and $102,615 other international) and $35,569 related to refining, marketing, and transportation - United Kingdom.

2 As set forth in Note B to the consolidated financial statements, the effect on operating income for the exploration and production segment from adoption of SFAS No. 109, Accounting for Income Taxes, was a reduction of $10,916.

3 Amounts for 1994 and 1993 were reclassified to conform to 1995 presentation.

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

The following schedules are presented in accordance with Statement of Financial Accounting Standards No. 69 (SFAS No. 69), Disclosures about Oil and Gas Producing Activities. The schedules 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 GAS RESERVES

Reserves of crude oil, condensate, and natural gas liquids and natural gas are estimated by Company engineers and 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. Quantities reported are considered reasonable, but they are subject to future revisions, some of which may be substantial, as additional information becomes available. Such additional knowledge may be gained as the result of: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes, and other economic factors.

Regulations published by the Securities and Exchange Commission define proved reserves as those volumes of crude oil, condensate, and 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 those volumes expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are those volumes expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.

Production quantities shown are net volumes withdrawn from reservoirs. These generally differ from quantities sold 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. Such differences were insignificant for crude oil and liquids. For natural gas, they amounted to approximately .5 billion cubic feet in 1995, .7 billion cubic feet in 1994, and .9 billion cubic feet in 1993. Crude oil and natural gas liquids reserves reported under the heading "Other" were located in Spain and Gabon.

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

Reserves of synthetic crude oil in Canada are attributable to the Syncrude project and are based on an estimated average gross production rate through the year 2025 of 195,300 barrels a day less estimated net profit royalty. Proved reserves will change if the future average production rate varies from the current estimated rate, which is based on the actual rate in 1995, or the operating permit is extended beyond 2025.

SCHEDULE 4 - 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-percent annual discount factor and year-end (1995 and 1994) 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 calculated 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 a broad range of judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts. Average crude oil prices at year-end 1995 used for this calculation were $18.04 a barrel for the United States, $16.48 for Canadian light, $9.66 for Canadian heavy, $17.59 for Hibernia, $18.85 for the United Kingdom, and $13.24 for Ecuador. Average natural gas prices were $2.51 an MCF for the United States, $1.02 for Canada, $2.21 for the United Kingdom, and $2.70 for Spain.

Schedule 4 also presents a summary of the principal reasons for change in the standardized measure of discounted future net cash flows for each of the three years ended December 31, 1995.

SCHEDULE 6 - RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES
Results of operations from exploration and production activities by geographic area are reported on this schedule as if these activities were a separate corporate entity rather than part of an integrated operation that will ultimately refine crude oil and sell refined products. Results of oil and gas producing activities include certain unusual or infrequently occurring items that are reviewed in Management's Discussion and Analysis (see page 24), and should be considered in conjunction with the Company's overall performance.

SCHEDULE 1 - ESTIMATED NET PROVED OIL RESERVES

	Crude Oil, Condensate, and Natural Gas Liquids							
(Millions of barrels)	United States	Canada*	United Kingdom	Ecuador	Other	Total	Synthetic Oil - Canada	Total
PROVED								
JANUARY 1, 1993	23.2	22.3	13.1	35.6	1.8	96.0	--	96.0
Revisions of previous estimates	.3	.8	(.5)	(2.0)	.7	(.7)	--	(.7)
Purchases of minerals in place	--	14.8	16.5	--	--	31.3	83.8	115.1
Extensions, discoveries, and other additions	1.5	3.2	--	--	--	4.7	--	4.7
Production	(5.0)	(4.6)	(2.4)	--	(.6)	(12.6)	--	(12.6)
Sales of minerals in place	--	(.1)	--	--	--	(.1)	--	(.1)
DECEMBER 31, 1993	20.0	36.4	26.7	33.6	1.9	118.6	83.8	202.4
Revisions of previous estimates	4.3	2.8	(2.5)	2.1	(1.5)	5.2	18.3	23.5
Purchases of minerals in place	--	.5	5.2	--	--	5.7	--	5.7
Extensions, discoveries, and other additions	5.1	2.7	--	--	--	7.8	--	7.8
Production	(4.9)	(4.5)	(4.9)	(.7)	(.4)	(15.4)	(3.3)	(18.7)
Sales of minerals in place	--	(.4)	--	--	--	(.4)	--	(.4)
DECEMBER 31, 1994	24.5	37.5	24.5	35.0	--	121.5	98.8	220.3
REVISIONS OF PREVIOUS ESTIMATES	3.9	--	.7	(3.5)	--	1.1	.7	1.8
PURCHASES OF MINERALS IN PLACE	.2	2.0	--	--	--	2.2	--	2.2
EXTENSIONS, DISCOVERIES, AND OTHER ADDITIONS	1.0	3.6	20.3	--	--	24.9	--	24.9
PRODUCTION	(5.0)	(5.1)	(5.5)	(1.9)	--	(17.5)	(3.3)	(20.8)
SALES OF MINERALS IN PLACE	--	(1.7)	--	--	--	(1.7)	--	(1.7)
DECEMBER 31, 1995	24.6	36.3	40.0	29.6	--	130.5	96.2	226.7
PROVED DEVELOPED								
January 1, 1993	16.3	22.2	11.7	--	1.8	52.0	--	52.0
December 31, 1993	13.2	22.4	20.8	--	1.9	58.3	83.8	142.1
December 31, 1994	15.2	23.6	19.2	3.8	--	61.8	80.5	142.3
DECEMBER 31, 1995	21.3	22.4	19.5	7.8	--	71.0	69.9	140.9

*Excludes 24.7 million barrels of crude oil to be added to proved reserves subsequent to start-up of production from the Hibernia oil field.

[GRAPH--ESTIMATED NET PROVED OIL RESERVES]

[GRAPH--ESTIMATED NET PROVED GAS RESERVES]

[GRAPH--ESTIMATED NET PROVED HYDROCARBON RESERVES]

SCHEDULE 2 - ESTIMATED NET PROVED NATURAL GAS RESERVES

(Billions of cubic feet)	United States	Canada	United Kingdom	Spain	Total
PROVED					
JANUARY 1, 1993	445.4	200.4	35.4	4.1	685.3
Revisions of previous estimates	48.0	(10.5)	.6	4.1	42.2
Purchases of minerals in place	.3	.9	--	--	1.2
Extensions, discoveries, and other additions	14.8	5.5	--	5.9	26.2
Production	(79.5)	(13.4)	(4.8)	(3.5)	(101.2)
Sales of minerals in place	--	(.2)	--	--	(.2)
DECEMBER 31, 1993	429.0	182.7	31.2	10.6	653.5
Revisions of previous estimates	20.2	(2.9)	2.1	1.2	20.6
Purchases of minerals in place	--	.5	--	--	.5
Extensions, discoveries, and other additions	53.2	11.0	--	--	64.2
Production	(72.1)	(13.8)	(3.7)	(4.6)	(94.2)
Sales of minerals in place	(.2)	(.8)	--	--	(1.0)
DECEMBER 31, 1994	430.1	176.7	29.6	7.2	643.6
REVISIONS OF PREVIOUS ESTIMATES	3.8	(5.2)	1.9	.6	1.1
PURCHASES OF MINERALS IN PLACE	2.8	5.8	--	--	8.6
EXTENSIONS, DISCOVERIES, AND OTHER ADDITIONS	64.1	2.0	19.8	--	85.9
PRODUCTION	(69.3)	(15.2)	(3.9)	(4.0)	(92.4)
SALES OF MINERALS IN PLACE	--	(4.0)	--	--	(4.0)
DECEMBER 31, 1995	431.5	160.1	47.4	3.8	642.8
PROVED DEVELOPED					
January 1, 1993	217.0	164.0	32.3	4.1	417.4
December 31, 1993	239.1	158.0	28.1	10.6	435.8
December 31, 1994	221.6	165.0	29.6	7.2	423.4
DECEMBER 31, 1995	229.0	150.0	27.6	3.8	410.4

SCHEDULE 3 - CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES

(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Other	Subtotal	Synthetic Oil - Canada	Total
DECEMBER 31, 1995								
UNPROVED OIL AND GAS PROPERTIES	$ 88.5	28.8	7.9	--	4.0	129.2	--	129.2
PROVED OIL AND GAS PROPERTIES	1,405.9	599.5(1)	582.4	167.1	122.9	2,877.8	119.3	2,997.1
GROSS CAPITALIZED COSTS	1,494.4	628.3	590.3	167.1	126.9	3,007.0	119.3	3,126.3
ACCUMULATED DEPRECIATION, DEPLETION, AND AMORTIZATION								
UNPROVED OIL AND GAS PROPERTIES	(55.3)	(15.7)	(.8)	--	(3.8)	(75.6)	--	(75.6)
PROVED OIL AND GAS PROPERTIES(2)	(1,186.2)	(254.0)	(412.5)	(114.5)	(116.2)	(2,083.4)	(8.8)	(2,092.2)
NET CAPITALIZED COSTS	$ 252.9	358.6	177.0	52.6	6.9	848.0	110.5	958.5
December 31, 1994(3)								
Unproved oil and gas properties	$ 109.2	27.5	21.0	--	9.8	167.5	--	167.5
Proved oil and gas properties	1,397.7	517.6(1)	548.2	149.6	109.9	2,723.0	108.9	2,831.9
Gross capitalized costs	1,506.9	545.1	569.2	149.6	119.7	2,890.5	108.9	2,999.4
Accumulated depreciation, depletion, and amortization								
Unproved oil and gas properties	(55.0)	(15.3)	(.8)	--	(5.9)	(77.0)	--	(77.0)
Proved oil and gas properties(2)	(1,136.1)	(239.5)	(331.5)	(3.8)	(100.4)	(1,811.3)	(4.4)	(1,815.7)
Net capitalized costs	$ 315.8	290.3	236.9	145.8	13.4	1,002.2	104.5	1,106.7

1 Includes costs of $166.2 in 1995 and $107.5 in 1994 related to oil fields under development offshore Newfoundland.
2 Does not include reserve for dismantlement costs of $144.9 in 1995 and $138.9 in 1994.
3 Reclassified to conform to 1995 presentation.

SCHEDULE 4 - STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES(1)

(Millions of dollars)	United States	Canada(2)	United Kingdom	Ecuador	Other	Total
DECEMBER 31, 1995						
FUTURE CASH INFLOWS	$1,525.3	691.2	824.3	391.2	10.4	3,442.4
FUTURE DEVELOPMENT COSTS	(191.5)	(156.2)	(112.1)	(57.3)	--	(517.1)
FUTURE PRODUCTION AND ABANDONMENT COSTS	(402.9)	(281.3)	(303.0)	(139.0)	(2.3)	(1,128.5)
FUTURE INCOME TAXES	(281.4)	(43.1)	(100.5)	(13.9)	(1.0)	(439.9)
FUTURE NET CASH FLOWS	649.5	210.6	308.7	181.0	7.1	1,356.9
10% ANNUAL DISCOUNT FOR ESTIMATED TIMING OF CASH FLOWS	(222.0)	(100.7)	(91.1)	(89.7)	.2	(503.3)
STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS	$ 427.5	109.9	217.6	91.3	7.3	853.6

December 31, 1994						
Future cash inflows	$1,071.3	714.4	453.5	387.2	21.1	2,647.5
Future development costs	(160.2)	(204.1)	(25.8)	(68.7)	(1.8)	(460.6)
Future production and abandonment costs	(358.7)	(301.5)	(233.9)	(118.2)	(1.8)	(1,014.1)
Future income taxes	(147.0)	(50.1)	11.8	(18.0)	(3.6)	(206.9)
Future net cash flows	405.4	158.7	205.6	182.3	13.9	965.9
10% annual discount for estimated timing of cash flows	(139.1)	(98.6)	(29.8)	(85.7)	(1.1)	(354.3)
Standardized measure of discounted future net cash flows	$ 266.3	60.1	175.8	96.6	12.8	611.6

1 Excludes future net cash flows from synthetic oil.
2 Excludes future net cash flows attributable to 24.7 million barrels of crude oil to be added to proved reserves subsequent to start-up of production from the Hibernia oil field.

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

(Millions of dollars)	1995	1994	1993
Net changes in prices, production costs, and development costs	$ 81.3	(225.7)	(282.6)
Sales and transfers of oil and gas produced, net of production costs	(226.2)	(161.1)	(167.0)
Net change due to extensions, discoveries, and improved recovery	298.1	86.1	47.8
Net change due to purchases and sales of minerals in place	7.5	35.9	26.5
Development costs incurred during the period	132.8	173.9	150.6
Accretion of discount	76.1	73.3	82.2
Revisions of previous quantity estimates	25.4	46.3	53.4
Net change in income taxes	(153.0)	53.6	53.8
Net increase (decrease)	242.0	82.3	(35.3)
Standardized measure at January 1	611.6	529.3	564.6
Standardized measure at December 31	$ 853.6	611.6	529.3

SCHEDULE 5 - COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION, AND DEVELOPMENT ACTIVITIES

	1995							
(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Other	Subtotal	Synthetic Oil - Canada	Total
Property acquisition costs								
Unproved	$ 7.0	3.0	.1	--	.2	10.3	--	10.3
Proved	2.5	4.7	--	--	--	7.2	--	7.2
Total acquisition costs	9.5	7.7	.1	--	.2	17.5	--	17.5
Exploration costs	41.7	7.5	6.8	--	9.3	65.3	--	65.3
Development costs	20.0	76.8	25.6	17.6	1.6	141.6	7.3	148.9
Total capital expenditures	71.2	92.0	32.5	17.6	11.1	224.4	7.3	231.7
Charged to expense								
Dry hole expense	25.9	2.9	.7	--	1.4	30.9	--	30.9
Geophysical and other costs	9.2	2.9	4.3	--	7.8	24.2	--	24.2
Total charged to expense	35.1	5.8	5.0	--	9.2	55.1	--	55.1
Expenditures capitalized	$36.1	86.2	27.5	17.6	1.9	169.3	7.3	176.6

SCHEDULE 6 - RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

	1995							
(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Other	Subtotal	Synthetic Oil - Canada	Total
Revenues								
Crude oil and natural gas liquids								
Transfers to consolidated operations	$67.8	45.7	20.9	--	--	134.4	34.9	169.3
Sales to unaffiliated enterprises	14.4	22.6	71.7	25.9	--	134.6	20.8	155.4
Natural gas	112.8	14.5	9.8	--	11.3	148.4	--	148.4
Total oil and gas revenues	195.0	82.8	102.4	25.9	11.3	417.4	55.7	473.1
Other operating	10.6	--	8.4	.2	.6	19.8	.6	20.4

	United States	Canada	United Kingdom	Ecuador	Other	Subtotal	Synthetic Oil - Canada	Total
Total revenues	205.6	82.8	110.8	26.1	11.9	437.2	56.3	493.5
Costs and deductions								
Production costs	53.5	27.0	36.1	11.6	.1	128.3	39.2	167.5
Exploration expenses	35.1	5.8	5.0	--	9.2	55.1	--	55.1
Undeveloped lease amortization	6.9	2.3	--	--	1.5	10.7	--	10.7
Depreciation, depletion, and amortization.	89.7	21.9	50.4	10.7	5.3	178.0	4.7	182.7
Impairment of long-lived assets	9.2	--	38.5	100.0	2.6	150.3	--	150.3
Selling and general expenses	14.1	5.6	3.5	.1	1.4	24.7	.1	24.8
Total costs and deductions	208.5	62.6	133.5	122.4	20.1	547.1	44.0	591.1
	(2.9)	20.2	(22.7)	(96.3)	(8.2)	(109.9)	12.3	(97.6)
Income tax provisions (benefits)	(6.6)	6.3	(10.8)	1.0	(1.4)	(11.5)	4.5	(7.0)
Results of operations*	$ 3.7	13.9	(11.9)	(97.3)	(6.8)	(98.4)	7.8	(90.6)

*Excludes corporate overhead and interest.

SCHEDULE 5 - COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION, AND DEVELOPMENT ACTIVITIES (Continued)

1994*								
(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Other	Subtotal	Synthetic Oil - Canada	Total
Property acquisition costs								
Unproved	6.8	2.5	--	--	--	9.3	--	9.3
Proved	--	22.2	4.4	--	--	26.6	--	26.6
Total acquisition costs	6.8	24.7	4.4	--	--	35.9	--	35.9
Exploration costs	49.2	11.7	11.6	--	4.4	76.9	--	76.9
Development costs	23.4	68.7	18.2	52.8	5.1	168.2	5.3	173.5
Total capital expenditures	79.4	105.1	34.2	52.8	9.5	281.0	5.3	286.3
Charged to expense								
Dry hole expense	11.4	2.4	2.8	--	--	16.6	--	16.6
Geophysical and other costs	8.2	2.6	2.4	--	1.9	15.1	--	15.1
Total charged to expense	19.6	5.0	5.2	--	1.9	31.7	--	31.7
Expenditures capitalized	59.8	100.1	29.0	52.8	7.6	249.3	5.3	254.6

1993*								
(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Other	Subtotal	Synthetic Oil - Canada	Total
Property acquisition costs								
Unproved	2.2	1.9	--	--	.3	4.4	--	4.4
Proved	1.4	5.0	144.3	--	--	150.7	109.0	259.7
Total acquisition costs	3.6	6.9	144.3	--	.3	155.1	109.0	264.1
Exploration costs	39.9	9.2	5.0	--	6.1	60.2	--	60.2
Development costs	49.4	52.7	26.0	67.7	--	195.8	--	195.8
Total capital expenditures	92.9	68.8	175.3	67.7	6.4	411.1	109.0	520.1
Charged to expense								
Dry hole expense	15.2	2.4	(.5)	--	4.4	21.5	--	21.5
Geophysical and other costs	5.8	2.6	2.5	--	1.6	12.5	--	12.5
Total charged to expense	21.0	5.0	2.0	--	6.0	34.0	--	34.0
Expenditures capitalized	71.9	63.8	173.3	67.7	.4	377.1	109.0	486.1

*Reclassified to conform to 1995 presentation.

SCHEDULE 6 - RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES (Continued)

1994(1)								
(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Other	Subtotal	Synthetic Oil - Canada	Total
Revenues								

Crude oil and natural gas liquids								
Transfers to consolidated operations ..	60.3	27.7	--	--	--	88.0	30.6	118.6
Sales to unaffiliated enterprises	13.4	26.5	77.8	7.9	5.9	131.5	22.1	153.6
Natural gas	136.1	19.7	9.0	--	11.7	176.5	--	176.5
Total oil and gas revenues	209.8	73.9	86.8	7.9	17.6	396.0	52.7	448.7
Other operating	5.7	.5	3.5	--	(.7)	9.0	--	9.0
Total revenues	215.5	74.4	90.3	7.9	16.9	405.0	52.7	457.7
Costs and deductions								
Production costs	55.5	24.3	32.1	5.9	4.3	122.1	40.0	162.1
Exploration expenses	19.6	5.0	5.2	--	1.9	31.7	--	31.7
Undeveloped lease amortization	8.2	2.8	--	--	--	11.0	--	11.0
Depreciation, depletion, and amortization	93.1	19.9	38.5	3.8	1.0	156.3	5.2	161.5
Impairment of long-lived assets	--	--	--	--	--	--	--	--
Selling and general expenses	13.8	4.6	3.1	.1	1.3	22.9	.1	23.0
Total costs and deductions	190.2	56.6	78.9	9.8	8.5	344.0	45.3	389.3
	25.3	17.8	11.4	(1.9)	8.4	61.0	7.4	68.4
Income tax provisions (benefits)	7.2	7.8	(1.0)	.5	--	14.5	2.3	16.8
Results of operations(2)	18.1	10.0	12.4	(2.4)	8.4	46.5	5.1	51.6

(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Other	Subtotal	Synthetic Oil-Canada	Total
	1993(1)							
Revenues								
Crude oil and natural gas liquids								
Transfers to consolidated operations ..	65.1	27.0	--	--	--	92.1	--	92.1
Sales to unaffiliated enterprises	16.6	27.1	38.4	--	8.0	90.1	--	90.1
Natural gas	165.8	16.4	11.0	--	9.2	202.4	--	202.4
Total oil and gas revenues	247.5	70.5	49.4	--	17.2	384.6	--	384.6
Other operating	5.8	.9	2.2	--	(.6)	8.3	--	8.3
Total revenues	253.3	71.4	51.6	--	16.6	392.9	--	392.9
Costs and deductions								
Production costs	58.1	25.4	20.7	--	9.7	113.9	--	113.9
Exploration expenses	21.0	5.0	2.0	--	6.0	34.0	--	34.0
Undeveloped lease amortization	8.9	2.5	--	--	.7	12.1	--	12.1
Depreciation, depletion, and amortization	97.2	21.1	16.8	--	4.6	139.7	--	139.7
Impairment of long-lived assets	--	--	--	--	--	--	--	--
Selling and general expenses	14.3	5.7	3.3	.1	1.1	24.5	--	24.5
Total costs and deductions	199.5	59.7	42.8	.1	22.1	324.2	--	324.2
	53.8	11.7	8.8	(.1)	(5.5)	68.7	--	68.7
Income tax provisions (benefits)	21.1	5.4	(9.1)	--	--	17.4	--	17.4
Results of operations(2)	32.7	6.3	17.9	(.1)	(5.5)	51.3	--	51.3

1 Reclassified to conform to 1995 presentation.
2 Excludes corporate overhead and interest.

STATISTICAL SUMMARY

	1995	1994	1993	1992	1991
EXPLORATION AND PRODUCTION					
Net crude oil and condensate production - barrels a day					
United States..	12,772	12,503	12,864	12,586	12,565
Canada - light oil...	4,417	4,775	4,546	3,972	4,305
heavy oil..	8,864	6,840	7,449	5,366	4,744
synthetic oil..	8,832	9,065	-	-	-
United Kingdom...	14,588	13,389	6,342	5,931	7,607
Ecuador..	5,274	1,967	-	-	-
Other international..	117	1,038	1,550	1,350	2,985
Net natural gas liquids production - barrels a day					
United States..	964	852	863	768	761
Canada...	740	748	697	847	368
United Kingdom...	447	151	-	-	160
Total	57,015	51,328	34,311	30,820	33,495
Net natural gas sold - thousands of cubic feet a day					
United States..	189,250	195,555	215,471	188,068	151,157
Canada...	40,907	37,945	36,792	30,328	25,679
United Kingdom...	10,671	10,138	13,074	12,802	9,354
Spain..	10,898	12,620	9,571	19,402	22,207
Total	251,726	256,258	274,908	250,600	208,397

Total hydrocarbons produced - equivalent barrels(1) a day	98,969	94,038	80,129	72,587	68,228
Estimated net hydrocarbon reserves - million equivalent barrels(1, 2)	333.8	327.6	311.3	210.2	202.8
Weighted average sales prices(3)					
Crude oil and condensate - dollars a barrel					
United States	$16.61	15.36	16.60	18.85	19.80
Canada(4) - light oil	16.45	14.61	15.01	16.69	17.47
heavy oil	12.10	10.56	9.84	11.02	9.09
synthetic oil	17.28	15.92	-	-	-
United Kingdom	16.96	15.77	16.63	18.86	19.86
Ecuador	13.03	12.07	-	-	-
Other international	15.12	14.80	14.14	18.85	16.57
Natural gas liquids - dollars a barrel					
United States	12.62	12.19	13.36	14.71	15.65
Canada(4)	9.70	9.21	9.59	9.74	13.91
United Kingdom	13.99	12.16	-	-	15.35
Natural gas - dollars a thousand cubic feet					
United States	1.64	1.91	2.10	1.75	1.62
Canada(4)	.97	1.42	1.22	1.01	1.12
United Kingdom(4)	2.53	2.43	2.31	2.86	3.00
Spain(4)	2.88	2.55	2.64	2.58	2.87
Net wells completed					
Oil wells - United States	3.0	2.6	3.0	4.9	5.7
Canada	29.6	20.7	24.3	19.1	10.0
Other	3.7	2.7	2.0	.3	.4
Gas wells - United States	3.6	4.0	8.5	5.1	9.4
Canada	2.3	14.5	4.1	2.4	1.4
Other	.2	.4	-	.5	.5
Dry holes - United States	1.9	4.1	6.5	5.2	5.9
Canada	5.9	6.5	6.9	2.6	6.9
Other	.6	.5	.6	2.0	1.4
Total	50.8	56.0	55.9	42.1	41.6
Net undeveloped acreage - thousands of acres(2)	13,107	12,218	9,306	8,389	10,114

1 Natural gas converted on an energy equivalent basis of 6:1.
2 At December 31.
3 Includes intracompany and affiliated company transfers at market prices.
4 U.S. dollar equivalent.

	1995	1994	1993	1992	1991
REFINING					
Crude capacity* of refineries - barrels per stream day	167,400	167,400	167,400	167,400	167,400
Inputs/yields at refineries - barrels a day					
Crude - Meraux, Louisiana	91,940	78,252	78,732	80,842	75,059
Superior, Wisconsin	33,217	30,592	30,358	26,207	26,916
Milford Haven, Wales	30,346	32,038	27,991	24,245	25,969
Other feedstocks	8,280	8,731	10,350	12,857	11,310
Total inputs	163,783	149,613	147,431	144,151	139,254
Gasoline	73,964	67,746	66,460	67,710	60,491
Kerosine	15,113	16,989	16,024	13,338	15,662
Diesel and home heating oils	39,351	35,553	34,356	32,848	32,055
Residuals	19,641	15,444	16,441	18,474	17,237
Asphalt, LPG, and other	10,158	10,077	9,627	7,133	9,838
Fuel and loss	5,556	3,804	4,523	4,648	3,971
Total yields	163,783	149,613	147,431	144,151	139,254
Average cost of crude inputs to refineries - dollars a barrel					
United States	$17.34	15.81	16.81	18.93	19.72
United Kingdom	17.59	16.32	17.44	19.84	20.74
MARKETING					
Products sold - barrels a day					
United States - Gasoline	63,364	60,327	61,577	59,128	50,075
Kerosine	9,945	11,911	11,682	10,855	12,156
Diesel and home heating oils	33,495	30,172	29,252	26,446	24,626
Residuals	14,775	10,454	11,812	12,339	11,926
Asphalt, LPG, and other	8,815	7,754	6,519	5,611	5,228
	130,394	120,618	120,842	114,379	104,011
United Kingdom - Gasoline	14,277	16,601	13,270	13,549	13,030
Kerosine	4,387	6,044	4,660	2,724	3,147
Diesel and home heating oils	6,647	9,200	7,525	7,112	7,593
Residuals	4,993	5,157	5,068	6,245	5,383
LPG and other	930	3,264	1,996	1,861	4,213
	31,234	40,266	32,519	31,491	33,366
Canada	283	246	234	172	129
Total products sold	161,911	161,130	153,595	146,042	137,506
Average gross margin on products sold - dollars a barrel					
United States	$ .46	1.07	.82	.48	1.59

United Kingdom	2.26	2.17	3.08	2.67	3.52
Branded retail outlets*					
United States	514	588	606	643	622
United Kingdom	465	470	428	391	370
Canada	7	8	8	7	6
TRANSPORTATION					
Pipeline throughputs of crude oil - barrels a day - Canada	173,720	159,517	151,722	118,050	90,660

* At December 31.

	1995	1994	1993	1992	1991
FARM, TIMBER, AND REAL ESTATE					
Acres owned(1) - Farmland	36,000	36,000	36,000	36,000	36,000
Timberland	341,000	341,000	341,000	342,000	341,000
Real estate	9,000	10,000	10,000	10,000	10,000
Acres harvested					
Cotton	4,263	3,972	4,839	4,518	4,099
Soybeans	14,695	14,318	14,863	12,798	15,584
Wheat	2,787	1,405	1,482	1,209	6,391
Corn	5,340	5,567	3,717	4,586	4,162
Rice	502	491	330	622	1,019
Yields per acre					
Cotton - pounds	749	883	661	831	969
Soybeans - bushels	27	40	24	39	30
Wheat - bushels	41	59	40	59	21
Corn - bushels	86	113	70	118	87
Rice - bushels	91	124	107	107	112
Estimated standing pine timber inventories(1)					
Sawtimber - MBF-DS (thousand board feet - Doyle scale)	765,000	812,000	810,000	805,000	766,000
Pulpwood - cords	1,180,000	991,000	963,000	940,000	989,000
Company-owned pine timber harvested					
Average sawtimber price(2) - dollars an MBF-DS	$ 406	372	310	274	202
Sawtimber - MBF-DS	35,736	40,616	37,635	30,177	32,956
Pulpwood - cords	12,799	12,988	12,536	8,767	15,038
Sawmills					
Production					
Finished lumber - MBF (thousand board feet)	140,555	136,713	112,365	101,203	92,846
Pine chips - tons	224,148	227,506	193,618	236,180	229,105
Annual capacity(1) - MBF	165,000	165,000	122,600	100,100	100,100
Sales of finished lumber					
MBF	140,549	138,377	115,136	105,619	95,024
Average price - dollars an MBF	$ 318	363	335	259	215
Average margin - dollars an MBF	12	87	82	34	13
Real estate					
Residential lots sold	53	99	147	120	98
Average price - dollars a lot	$46,200	60,400	48,200	53,200	49,700
Commercial acres sold	--	--	--	--	17
Average price - dollars an acre	$ --	--	--	--	32,700
STOCKHOLDER AND EMPLOYEE DATA					
Common shares outstanding(1) (thousands)	44,833	44,832	44,808	44,844	44,966
Number of stockholders of record(1)	4,873	4,778	5,265	6,522	5,826
Number of employees(1)	1,794	1,767	1,803	1,787	3,991
Average number of employees	1,786	1,778	1,787	1,857	4,001
Salaries, wages, and benefits (thousands)	$96,035	93,216	90,734	92,486	166,883

1 At December 31.
2 Includes intracompany transfers at market prices.

MURPHY OIL CORPORATION - CIK 0000717423

Appendix to Electronically Filed Exhibit 13
(1995 Annual Report to Security Holders, Which is Incorporated in This Form 10-K)
Providing a Narrative of Graphic and Image Material Appearing on Pages 4 Through 50 of Paper Format

Exhibit 13
Page No. Map Narrative

- ---------- -------------

5 Gulf of Mexico - The locations and areal extent of acreage under lease by the Company in the Gulf of Mexico (offshore Texas, Louisiana, Mississippi, Alabama, and Florida) are shown. Additionally, each lease is categorized as either: (1) producing or producible; (2) discovery--commerciality to be determined/facilities to be installed; (3) unexplored, dry hole(s), or noncommercial shows; or (4) unexplored--acquired in 1995.

7 Canada - The locations and areal extent of acreage under lease by the Company in British Columbia, Alberta, Saskatchewan, and Manitoba are shown. Additionally, specific areas of production are identified along with the types of production--natural gas, light oil, heavy oil, and oil sands.

8 Offshore Eastern Canada - Depicted are the locations in the North Atlantic Ocean east of Newfoundland of the Hibernia and Terra Nova oil fields, in which the Company holds interests, and the location where the production platform for the Hibernia field is being constructed. Also depicted is an exploration license that the Company acquired in 1995 in the Jeanne d'Arc Basin, midway between the Hibernia and Terra Nova fields.

9 North Sea - The locations and areal extent of producing and nonproducing acreage under license by the Company, primarily in the U.K. sector of the North Sea, are shown. Blocks on which the Company has significant oil and/or natural gas production, or significant ongoing development projects, are specifically identified.

12 Pakistan - The location and areal extent of two separate exploration concessions located in Pakistan are shown. One concession, acquired in 1995 in the Middle Indus Basin, includes three blocks covering 4.4 million acres. Operations in the 6.7-million-acre Kharan concession in western Pakistan remain suspended under force majeure.

15 United States - The locations of the Company's refineries in Superior, Wisconsin, and Meraux, Louisiana, are shown along with a depiction of the predominant routes and means of moving crude oil to the refineries, the routes and means of moving finished products from the refineries into marketing areas, the terminal facilities used to store and/or distribute products to wholesalers and consumers, and the areal extent of the Company's marketing territories in 11 states in the Southeast and four states in the upper-Midwest.

Exhibit 13
Page No.   Map Narrative (Continued)
- ---------- -------------

16 United Kingdom - The Company's jointly owned refinery in Milford Haven, Wales, is shown along with a depiction of the normal route and means of moving crude oil to the refinery, the routes and means of moving finished products from the refinery into U.K. marketing areas, locations of the terminal facilities used to store and/or distribute products to wholesalers and consumers, and the areal extent of the Company's marketing territory, which covers most of England and southern Wales.

17 Western Crude Oil Pipeline Systems - The locations are shown in southern Alberta and Saskatchewan of major Canadian crude oil pipelines and two pipeline systems that are partially owned and operated by the Company and deliver heavy oil into one of the major pipelines. In addition, the locations are shown of two pipelines owned by the Company that transport crude oil to the U.S. border for further movement to refining centers in Montana, Wyoming, and Colorado through pipelines owned by others and a pipeline system in

Montana and Wyoming in which the Company has an ownership.

Picture/Schematic Narrative

6 An aerial view is shown of a semi-submersible drilling barge in the Gulf of Mexico on location at Viosca Knoll Block 783, where the Company holds a 30-percent interest in the Tahoe field. After a lengthy performance evaluation of the first well in the field and interpretation of additional 3-D seismic information, the Company is now engaged in a drilling program to bring additional production from the field on stream by the fourth quarter of 1996.

8 A view is shown at Bull Arm, Newfoundland, depicting topside modules for the Hibernia oil field being assembled on a pier. After assembly is completed in the spring of 1997, the modules are to be mounted on a concrete and steel Gravity Base Structure, which is being constructed nearby. The completed 735-feet tall, 650,000-ton structure will be towed at mid-year 1997 to the field, which is approximately 200 miles east of St. John's, Newfoundland.

10 A schematic drawing depicts a recently approved production plan for seven fields in the U.K. North Sea; the fields are known collectively as the Eastern Trough Area Project. The drawing is a cut-away view from the ocean surface, through the ocean floor, and into the subsurface hydrocarbon formations of the fields. Murphy has a 12.7-percent ownership interest in two of the fields--Mungo and Monan, which are expected to reach peak gross production of 65,000 barrels of oil a day in 1999.

Exhibit 13 Page No.	Picture/Schematic Narrative (Continued)
11	A schematic drawing depicts the proposed development of the Schiehallion field on Blocks 204/20 and 204/25, located west of the Shetland Islands. The drawing is a cut-away view from the ocean surface, through the ocean floor, and into the subsurface hydrocarbon formation. Development of Schiehallion, in which the Company owns a 5.9-percent interest, is expected to begin in the second quarter of 1996, with first production in late 1997 or early 1998.
14	A view at dusk is shown from the eastern edge of the Company's 100,000-barrel-a-day refinery at Meraux, Louisiana; the refinery established a new record of 91,940 barrels of crude processed per day during 1995.
15	An outside view of a U.S. convenience store is shown as an example of the Company's newly introduced retail service station design.
16	A view is shown of the installation of the reactor vessel for a high-pressure distillate hydrotreater unit being built at the 30-percent owned Milford Haven, Wales, refinery. The hydrotreater unit is expected to be commissioned in late 1996 and will enable the refinery to make low-sulfur diesel fuel.
17	Company-owned trucking equipment is shown in front of several crude oil storage tanks at the Milk River, Alberta, terminal operated by the Company. The terminal serves as a crude handling location for the Milk River Pipeline, one of two Company-operated pipelines that carry Canadian crude oil to the U.S. border, from which it moves by other pipelines to Rocky Mountain area refineries.
18	Two Deltic Farm & Timber employees are shown taking growth rate measurements in a Company-owned pine forest. These measurements are used to make growth rate predictions for similar pine forest tracts.

19 An aerial view is shown of the highly rated golf course and certain surrounding single-family residences within the Chenal Valley development in western Little Rock, Arkansas.

Graph Narrative

4 INCOME CONTRIBUTION* - EXPLORATION AND PRODUCTION
Scale - 0 to 50 (millions of dollars).

	1991	1992	1993	1994	1995
Income*	23.4	35.9	36.9	45.2	29.5

*Before unusual or infrequently occurring items.

This is a vertical bar graph with each year's value printed above the appropriate bar.

Exhibit 13 Page No. — Graph Narrative (Continued)

4 CAPITAL EXPENDITURES - EXPLORATION AND PRODUCTION
Scale - 0 to 600 (millions of dollars).

	1991	1992	1993	1994	1995
Proved Property Acquisitions (top)	.3	13.9	259.7	26.6	7.2
Development Costs	45.7	36.8	195.8	173.5	148.9
Exploration Costs (bottom)	102.0	87.4	64.6	86.2	75.6
Totals	148.0	138.1	520.1	286.3	231.7

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

4 NET HYDROCARBONS PRODUCTION
Scale 0 to 120 (thousands of barrels a day on an energy equivalent basis).

	1991	1992	1993	1994	1995
Other International (top)	6.7	4.6	3.2	5.1	7.2
United Kingdom	9.3	8.1	8.5	15.2	16.8
Canada	13.7	15.2	18.8	27.8	29.7
United States (bottom)	38.5	44.7	49.6	45.9	45.3
Totals	68.2	72.6	80.1	94.0	99.0

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

6 CRUDE OIL AND NGL PRODUCTION
Scale 0 to 70 (thousands of barrels a day).

1991	1992	1993	1994	1995

Other International (top)	3.0	1.3	1.6	3.0	5.4
United Kingdom	7.8	5.9	6.3	13.5	15.0
Canada - Synthetic Oil	-	-	-	9.1	8.9
Canada - Other Oil	9.4	10.2	12.7	12.4	14.0
United States (bottom)	13.3	13.4	13.7	13.3	13.7
Totals	33.5	30.8	34.3	51.3	57.0

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

6 NATURAL GAS SALES
Scale 0 to 320 (millions of cubic feet a day).

	1991	1992	1993	1994	1995
Spain (top)	22.2	19.4	9.5	12.6	10.9
United Kingdom	9.3	12.8	13.1	10.1	10.7
Canada	25.7	30.3	36.8	38.0	40.9
United States (bottom)	151.2	188.1	215.5	195.6	189.2
Totals	208.4	250.6	274.9	256.3	251.7

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

Exhibit 13 Page No.	Graph Narrative (Continued)
13	INCOME CONTRIBUTION* - REFINING, MARKETING, AND TRANSPORTATION Scale 0 to 50 (millions of dollars).

	1991	1992	1993	1994	1995
Income*	43.3	8.0	31.5	30.2	2.0

*Before unusual or infrequently occurring items.
This is a vertical bar graph with each year's value printed above the appropriate bar.

13 CAPITAL EXPENDITURES - REFINING, MARKETING, AND TRANSPORTATION
Scale 0 to 120 (millions of dollars).

	1991	1992	1993	1994	1995
Transportation (top)	3.3	6.0	3.6	3.2	3.5
Marketing	15.2	14.1	16.9	17.0	9.2
Refining (bottom)	44.6	48.0	66.4	74.5	40.9
Totals	63.1	68.1	86.9	94.7	53.6

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

13 REFINED PRODUCTS SOLD
Scale 0 to 200 (thousands of barrels a day).

	1991	1992	1993	1994	1995
United Kingdom (top)	33.4	31.5	32.5	40.3	31.2
United States (bottom)	104.1	114.5	121.1	120.8	130.7
Totals	137.5	146.0	153.6	161.1	161.9

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

17 CANADIAN PIPELINE THROUGHPUTS
Scale 0 to 200 (thousands of barrels a day).

	1991	1992	1993	1994	1995
Throughputs	90.7	118.1	151.7	159.5	173.7

This is a vertical bar graph with each year's value printed above the appropriate bar.

18 INCOME CONTRIBUTION - FARM, TIMBER, AND REAL ESTATE
Scale 0 to 20 (millions of dollars).

	1991	1992	1993	1994	1995
Income	4.8	8.4	13.1	17.5	9.0

This is a vertical bar graph with each year's value printed above the appropriate bar.

Exhibit 13 Page No.	Graph Narrative (Continued)

18 CAPITAL EXPENDITURES - FARM, TIMBER, AND REAL ESTATE
Scale 0 to 14 (millions of dollars).

	1991	1992	1993	1994	1995
Capital Expenditures	2.9	6.0	9.7	11.4	9.1

This is a vertical bar graph with each year's value printed above the appropriate bar.

18 SALES OF FINISHED LUMBER

Scale 0 to 160 (millions of board feet).

	1991	1992	1993	1994	1995
Lumber Sales	95.0	105.6	115.1	138.4	140.5

This is a vertical bar graph with each year's value printed above the appropriate bar.

20 INCOME EXCLUDING UNUSUAL ITEMS
Scale 0 to 100 (millions of dollars).

	1991	1992	1993	1994	1995
Income Excluding Unusual Items	57.7	54.9	76.4	86.3	33.4

This is a vertical bar graph with each year's value printed above the appropriate bar.

20 NET CASH PROVIDED BY OPERATING ACTIVITIES
Scale 0 to 420 (millions of dollars).

	1991	1992	1993	1994	1995
Cash Provided	213.6	284.2	363.0	337.3	322.9

This is a vertical bar graph with each year's value printed above the appropriate bar.

20 STOCKHOLDERS' EQUITY AT YEAR-END
Scale 0 to 1,500 (millions of dollars).

	1991	1992	1993	1994	1995
Stockholders' Equity	1,201	1,200	1,222	1,271	1,101

This is a vertical bar graph with each year's value printed above the appropriate bar.

21 INCOME CONTRIBUTION BY OPERATING FUNCTION*
Scale 0 to 120 (millions of dollars).

	1993	1994	1995
Farm, Timber, and Real Estate (top)	13.1	17.5	9.0
Refining, Marketing, and Transportation	31.5	30.2	2.0
Exploration and Production (bottom)	36.9	45.2	29.5
Totals	81.5	92.9	40.5

*Excludes Corporate and unusual or infrequently occurring items.

This is a stacked vertical bar graph with the value for each element printed within or beside the element.

Exhibit 13 Page No.	Graph Narrative (Continued)
22	RANGE OF U.S. CRUDE OIL SALES PRICES Scale 10 to 20 (dollars a barrel).

	1993	1994	1995
High Monthly Crude Oil Price (top of bar)	18.42	17.58	18.06
Average Crude Oil Price (colored line)	16.60	15.36	16.61
Low Monthly Crude Oil Price (bottom of bar)	12.52	12.71	15.42

This is a floating vertical bar graph with a contrasting-color line between the top and bottom each year and highs printed above bars, averages printed above colored lines, and lows printed below bars.

22 RANGE OF U.S. NATURAL GAS SALES PRICES
Scale 1.25 to 2.75 (dollars a thousand cubic feet).

	1993	1994	1995
High Monthly Natural Gas Price (top of bar)	2.51	2.40	2.45
Average Natural Gas Price (colored line)	2.10	1.91	1.64
Low Monthly Natural Gas Price (bottom of bar)	1.63	1.42	1.39

This is a floating vertical bar graph with a contrasting-color line between the top and bottom each year and highs printed above bars, averages printed above colored lines, and lows printed below bars.

23 EXPLORATION EXPENSES
Scale 0 to 75 (millions of dollars).

	1993	1994	1995
Undeveloped Lease Amortization (top)	12.1	11.0	10.7
Geological, Geophysical, and Other Costs	12.5	15.1	24.2
Dry Hole Costs (bottom)	21.5	16.6	30.9
Totals	46.1	42.7	65.8

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

24 AVERAGE SAWMILL MARGIN
Scale 0 to 100 (dollars a thousand board feet).

	1993	1994	1995
Average Margin	82	87	12

This is a vertical bar graph with each year's value printed above the appropriate bar.

Appendix to Electronically Filed Exhibit 13 (Contd.)

Exhibit 13 Page No.	Graph Narrative (Continued)
25	CAPITAL EXPENDITURES IN 1995 Scale 0 to 350 (millions of dollars).

	Percent
Other - $1.9 (top)	1
Farm, Timber, and Real Estate - $9.1	3
Refining, Marketing, and Transportation - $53.6	18
Exploration and Production - $231.7 (bottom)	78

This is a stacked vertical bar graph with a line from each component to its respective percentage and "Total - $296.3" printed below graph.

43 ESTIMATED NET PROVED OIL RESERVES
Scale 0 to 250 (millions of barrels).

	1991	1992	1993	1994	1995
Other International (top)	.2	1.8	1.9	-	-
Ecuador	33.5	35.6	33.6	35.0	29.6
United Kingdom	14.7	13.1	26.7	24.5	40.0
Canada	21.8	22.3	120.2	136.3	132.5
United States (bottom)	22.8	23.2	20.0	24.5	24.6
Totals	93.0	96.0	202.4	220.3	226.7

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

43 ESTIMATED NET PROVED GAS RESERVES
Scale 0 to 800 (billions of cubic feet).

	1991	1992	1993	1994	1995
Spain (top)	16.6	4.1	10.6	7.2	3.8
United Kingdom	41.1	35.4	31.2	29.6	47.4
Canada	204.9	200.4	182.7	176.7	160.1
United States (bottom)	396.2	445.4	429.0	430.1	431.5
Totals	658.8	685.3	653.5	643.6	642.8

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

43 ESTIMATED NET PROVED HYDROCARBON RESERVES
Scale 0 to 400 (millions of barrels on an energy equivalent basis).

	1991	1992	1993	1994	1995
Other International (top)	36.5	38.1	37.2	36.2	30.2
United Kingdom	21.5	19.0	31.9	29.4	47.9
Canada	56.0	55.7	150.7	165.8	159.2
United States (bottom)	88.8	97.4	91.5	96.2	96.5
Totals	202.8	210.2	311.3	327.6	333.8

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

EXHIBIT 21

MURPHY OIL CORPORATION

PARENTS AND SUBSIDIARIES AS OF DECEMBER 31, 1995

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
MURPHY OIL CORPORATION (REGISTRANT)		
A. Deltic Farm & Timber Co., Inc.	Arkansas	100.0
1. Chenal Properties, Inc.	Arkansas	100.0
2. Deltic Timber Purchasers, Inc.	Arkansas	100.0
B. El Dorado Engineering Inc.	Delaware	100.0
1. El Dorado Contractors Inc.	Delaware	100.0
C. Murphy Eastern Oil Company	Delaware	100.0
D. Murphy Exploration & Production Company (formerly Ocean Drilling & Exploration Company)	Delaware	100.0
1. Canam Offshore A. G. (Switzerland)	Switzerland	100.0
2. Canam Offshore Limited	Bahamas	100.0
a. Odeco Drilling Limited	Bahamas	100.0
b. Rimrock Offshore Limited	Bahamas	100.0
3. El Dorado Exploration, S.A.	Delaware	100.0
4. Mentor Holding Corporation	Delaware	100.0
a. Mentor Excess and Surplus Lines Insurance Company	Delaware	100.0
b. Mentor Insurance and Reinsurance Company	Louisiana	100.0
c. Mentor Insurance Limited	Bermuda	99.993
(1) Mentor Insurance Company (U.K.) Limited	England	100.0
(2) Mentor Underwriting Agents (U.K.) Limited	England	100.0
5. MEPCO Venezuela, Ltd.	Bahamas	100.0
6. Murphy Building Corporation	Delaware	100.0
7. Murphy Denmark Oil Company	Delaware	100.0
8. Murphy Ecuador Oil Company Ltd.	Bermuda	100.0
9. Murphy Equatorial Guinea Oil Company	Delaware	100.0
10. Murphy France Oil Company	Delaware	100.0
11. Murphy Indus Energy Ltd.	Bahamas	100.0
12. Murphy Ireland Oil Company	Delaware	100.0
13. Murphy Italy Oil Company	Delaware	100.0
14. Murphy New Zealand Oil Company	Delaware	100.0
15. Murphy Overseas Ventures Inc.	Delaware	100.0
16. Murphy Pacific Rim, Ltd.	Bahamas	100.0
17. Murphy Pakistan Oil Company	Delaware	100.0
18. Murphy Peru Oil Company, S.A.	Panama	100.0
19. Murphy Somali Oil Company	Delaware	100.0
20. Murphy-Spain Oil Company	Delaware	100.0
21. Murphy Western Oil Company	Delaware	100.0
22. Murphy Yemen Oil Company	Delaware	100.0
23. Norske Murphy Oil Company	Delaware	100.0
24. Norske Ocean Exploration Company	Delaware	100.0
25. Ocean Exploration Company	Delaware	100.0
26. Ocean France Oil Company	Delaware	100.0
27. Ocean Gabon Oil Company	Delaware	100.0
28. Ocean International Finance Corporation	Delaware	100.0
29. Ocean Spain Oil Company	Delaware	100.0

EXHIBIT 21 (CONTD.)

MURPHY OIL CORPORATION

PARENTS AND SUBSIDIARIES AS OF DECEMBER 31, 1995 (CONTD.)

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
MURPHY OIL CORPORATION (REGISTRANT) - Contd.		
D. Murphy Exploration & Production Company - Contd.		
30. Odeco Gabon Oil Company	Delaware	100.0
31. Odeco International Corporation	Panama	100.0
32. Odeco Italy Oil Company	Delaware	100.0
33. Sub Sea Offshore (M) Sdn. Bhd.	Malaysia	60.0
E. Murphy Oil Company, Ltd.	Canada	100.0
1. 340236 Alberta Ltd.	Canada	100.0
2. Manito Pipelines Ltd.	Canada	52.5
3. Murphy Atlantic Offshore Oil Company Ltd.	Canada	100.0
4. Wascana Pipe Line Ltd.	Canada	100.0
F. Murphy Oil USA, Inc.	Delaware	100.0
1. Arkansas Oil Company	Delaware	100.0
2. Murphy Gas Gathering Inc.	Delaware	100.0
3. Murphy Latin America Refining & Marketing, Inc.	Delaware	100.0
4. Murphy LOOP, Inc.	Delaware	100.0
5. Murphy Oil Trading Company (Eastern)	Delaware	100.0
6. Spur Oil Corporation	Delaware	100.0
G. Murphy Ventures Corporation	Delaware	100.0
H. New Murphy Oil (UK) Corporation	Delaware	100.0
1. Murphy Petroleum Limited	England	100.0
a. Murco Petroleum Limited	England	100.0
(1) Alnery No. 166 Ltd.	England	100.0
(2) European Petroleum Distributors Ltd.	England	100.0
(3) H. Hartley (Doncaster) Ltd.	England	100.0
(4) Murco Petroleum (Ireland) Ltd.	Ireland	100.0

EXHIBIT 23

INDEPENDENT AUDITORS' CONSENT

The Board of Directors
Murphy Oil Corporation:

We consent to incorporation by reference in the Registration Statements (Nos. 2-82818, 2-86749, and 2-86760) on Form S-8 and (No. 33-55161) on Form S-3 of Murphy Oil Corporation of our report dated March 1, 1996, relating to the consolidated balance sheets of Murphy Oil Corporation and Consolidated Subsidiaries as of December 31, 1995 and 1994, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 1995, which report is included in the December 31, 1995, annual report on Form 10-K of Murphy Oil Corporation. Our report refers to changes in 1995 in the method of accounting for the impairment of long-lived assets and for long-lived assets to be disposed of and to changes in 1993 in the methods of accounting for income taxes and postretirement benefits other than pensions.

KPMG PEAT MARWICK LLP

Shreveport, Louisiana
March 26, 1996

<ARTICLE> 5
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THIS FINANCIAL DATA SCHEDULE CONTAINS SUMMARY FINANCIAL INFORMATION EXTRACTED
FROM THE AUDITED CONSOLIDATED BALANCE SHEET AT DECEMBER 31, 1995, AND THE
AUDITED CONSOLIDATED STATEMENT OF INCOME FOR THE YEAR ENDED DECEMBER 31, 1995,
OF MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES AND IS QUALIFIED IN ITS
ENTIRETY BY REFERENCE TO SUCH FINANCIAL STATEMENTS.
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THIS RESTATED FINANCIAL DATA SCHEDULE CONTAINS SUMMARY FINANCIAL INFORMATION EXTRACTED FROM THE AUDITED CONSOLIDATED BALANCE SHEET AT DECEMBER 31, 1994, AND THE AUDITED CONSOLIDATED STATEMENT OF INCOME FOR THE YEAR THEN ENDED OF MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES AND IS QUALIFIED IN ITS ENTIRETY BY REFERENCE TO SUCH STATEMENTS AS RESTATED AT DECEMBER 31, 1995.
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<F1>AMOUNTS HAVE BEEN RECLASSIFIED TO CONFORM TO 1995 PRESENTATION.
</FN>

EXHIBIT 99.1

UNDERTAKINGS

To be incorporated by reference into Form S-8 Registration Statements No. 2-82818, 2-86749 and 2-86760, and Form S-3 Registration Statement No. 33-55161.

The undersigned registrant hereby undertakes:

(1) To file, during any period in which offers or sales are being made, a post-effective amendment to this registration statement:

(i) To include any prospectus required by section 10(a)(3) of the Securities Act of 1933;

(ii) To reflect in the prospectus any facts or events arising after the effective date of the registration statement (or the most recent post-effective amendment thereof) which, individually or in the aggregate, represents a fundamental change in the information set forth in the registration statement;

(iii) To include any material information with respect to the plan of distribution not previously disclosed in the registration statement or any material change to such information in the registration statement;

(2) That, for the purpose of determining any liability under the Securities Act of 1933, each such post-effective amendment shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

(3) To remove from registration by means of a post-effective amendment any of the securities being registered which remain unsold at the termination of the offering.

The undersigned registrant hereby undertakes that, for purposes of determining any liability under the Securities Act of 1933, each filing of the registrant's annual report pursuant to section 13(a) or section 15(d) of the Securities Exchange Act of 1934 (and, where applicable, each filing of an employee benefit plan's annual report pursuant to section 15(d) of the Securities Exchange Act of 1934) that is incorporated by reference in the registration statement shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

The undersigned registrant hereby undertakes:

(1) To deliver or cause to be delivered with the prospectus to each employee to whom the prospectus is sent or given a copy of the registrant's annual report to stockholders for its last fiscal year, unless such employee otherwise has received a copy of such report, in

which case the registrant shall state in the prospectus that it will promptly furnish, without charge, a copy of such report on written request of the employee. If the last fiscal year of the registrant has ended within 120 days prior to the use of the prospectus, the annual report of the registrant for the preceding fiscal year may be so delivered, but within such 120 day period the annual report for the last fiscal year will be furnished to each such employee.

(2) To transmit or cause to be transmitted to all employees participating in the plan who do not otherwise receive such material as stockholders of the registrant, at the time and in the manner such material is sent to its stockholders, copies of all reports, proxy statements and other communications distributed to its stockholders generally.

Where interests in a plan are registered herewith, the undersigned registrant and plan hereby undertake to transmit or cause to be transmitted promptly, without charge, to any participant in the plan who makes a written request, a copy of the then latest annual report of the plan filed pursuant to section 15(d) of the Securities Exchange Act of 1934 (Form 11-K). If such report is filed separately on Form 11-K, such form shall be delivered upon written request. If such report is filed as a part of the registrant's annual report on Form 10-K, that entire report (excluding exhibits) shall be delivered upon written request. If such report is filed as a part of the registrant's annual report to stockholders delivered pursuant to paragraph (1) or (2) of this undertaking, additional delivery shall not be required.

Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, or otherwise, the registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.