NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Amerada Hess Corporation and Consolidated Subsidiaries

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business: Amerada Hess Corporation and subsidiaries (the "Corporation") engage in the exploration for and the production, purchase, transportation and sale of crude oil and natural gas. These activities are conducted primarily in the United States, United Kingdom, Norway, Denmark, Equatorial Guinea and Algeria. The Corporation also has oil and gas activities in Azerbaijan, Gabon, Indonesia, Malaysia, Thailand and other countries. In addition, the Corporation manufactures, purchases, transports, trades and markets refined petroleum and other energy products. The Corporation owns 50% of HOVENSA L.L.C., a refinery joint venture in the United States Virgin Islands. An additional refining facility, terminals and retail gasoline stations are located on the East Coast of the United States.

In preparing financial statements, management makes estimates and assumptions that affect the reported amounts of assets and liabilities in the balance sheet and revenues and expenses in the income statement. Actual results could differ from those estimates. Among the estimates made by management are: oil and gas reserves, asset valuations, depreciable lives, pension liabilities, environmental obligations, dismantlement costs and income taxes.

Certain information in the financial statements and notes has been reclassified to conform with current period presentation.

Principles of Consolidation: The consolidated financial statements include the accounts of Amerada Hess Corporation and entities in which the Corporation owns more than a 50% voting interest or entities that the Corporation controls. The Corporation's undivided interests in unincorporated oil and gas exploration and production ventures are proportionately consolidated.

Investments in affiliated companies, 20% to 50% owned, including HOVENSA but excluding a trading partnership, are stated at cost of acquisition plus the Corporation's equity in undistributed net income since acquisition. The change in the equity in net income of these companies is included in non-operating income in the income statement. The Corporation consolidates the trading partnership in which it owns a 50% voting interest and over which it exercises control.

Intercompany transactions and accounts are eliminated in consolidation.

Revenue Recognition: The Corporation recognizes revenues from the sale of crude oil, natural gas, petroleum products and other merchandise when title passes to the customer.

The Corporation recognizes revenues from the production of natural gas properties in which it has an interest based on sales to customers. Differences between natural gas volumes sold and the Corporation's share of natural gas production are not material.

Cash and Cash Equivalents: Cash equivalents consist of highly liquid investments, which are readily convertible into cash and have maturities of three months or less when acquired.

Inventories: Crude oil and refined product inventories are valued at the lower of average cost or market. For inventories valued at cost, the Corporation uses principally the last-in, first-out (LIFO) inventory method.

Inventories of materials and supplies are valued at the lower of average cost or market.

Exploration and Development Costs: Oil and gas exploration and production activities are accounted for using the successful efforts method. Costs of acquiring unproved and proved oil and gas leasehold acreage, including lease bonuses, brokers' fees and other related costs, are capitalized.

Annual lease rentals and exploration expenses, including geological and geophysical expenses and exploratory dry hole costs, are expensed as incurred.

Costs of drilling and equipping productive wells, including development dry holes, and related production facilities are capitalized.

The costs of exploratory wells that find oil and gas reserves are capitalized pending determination of whether proved reserves have been found. In an area requiring a major capital expenditure before production can begin, an exploration well is carried as an asset if sufficient reserves are discovered to justify its completion as a production well, and additional exploration drilling is underway or firmly planned. The Corporation does not capitalize the cost of other exploratory wells for more than one year unless proved reserves are found.

Depreciation, Depletion and Amortization: The Corporation calculates depletion expense for acquisition costs of proved properties using the units of production method over proved oil and gas reserves. Depreciation and depletion expense for oil and gas production equipment and wells is calculated using the units of production method over proved developed oil and gas reserves. Depreciation of all other plant and equipment is determined on the straight-line method based on estimated useful lives.

Provisions for impairment of undeveloped oil and gas leases are based on periodic evaluations and other factors.

Asset Retirement Obligations: The Corporation recognizes a liability for the fair value of legally required asset retirement obligations associated with long-lived assets in the period in which the retirement obligations are incurred. The Corporation capitalizes the associated asset retirement costs as part of the carrying amount of the long-lived assets.

Retirement of Property, Plant and Equipment: Costs of property, plant and equipment retired or otherwise disposed of, less accumulated reserves, are reflected in non-operating income.

Impairment of Long-Lived Assets: The Corporation reviews long-lived assets, including oil and gas properties at a field level, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts are not expected to be recovered by undiscounted future cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is based on the estimated fair value of the assets determined by discounting anticipated future net cash flows. In the case of oil and gas fields, the net present value of future cash flows is based on management's best estimate of future prices, which is determined with reference to recent historical prices and published forward prices, applied to projected production volumes of individual fields and discounted at a rate commensurate with the risks involved. The projected production volumes represent reserves, including probable reserves, expected to be produced based on a stipulated amount of capital expenditures. The production volumes, prices and timing of production are consistent with internal projections and other externally reported information. Oil and gas prices used for determining asset impairments will generally differ from those used at year-end in the standardized measure of discounted future net cash flows.

Impairment of Equity Investees: The Corporation reviews equity method investments for impairment whenever events or changes in circumstances indicate that an other than temporary decline in value has occurred. The amount of the impairment is based on quoted market prices, where available, or other valuation techniques, including discounted cash flows.

Impairment of Goodwill: In accordance with FAS No. 142, *Goodwill and Other Intangible Assets*, goodwill cannot be amortized; however, it must be tested annually for impairment. This impairment test is calculated at the reporting unit level, which is the exploration and production segment for the Corporation's goodwill. The Corporation identifies potential impairments by comparing the fair value of the reporting unit to its book value, including goodwill. If the fair value of the reporting unit exceeds the carrying amount, goodwill is not impaired. If the carrying value exceeds the fair value, the Corporation calculates the possible impairment loss by comparing the implied fair value of goodwill with the carrying amount. If the implied fair value of goodwill is less than the carrying amount, an impairment would be recorded.

Maintenance and Repairs: The estimated costs of major maintenance, including turnarounds at the Port Reading refining facility, are accrued. Other expenditures for maintenance and repairs are charged against income as incurred. Renewals and improvements are treated as additions to property, plant and equipment, and items replaced are treated as retirements.

Environmental Expenditures: The Corporation capitalizes environmental expenditures that increase the life or efficiency of property or that reduce or prevent environmental contamination. The Corporation accrues for environmental expenses resulting from existing conditions related to past operations when the future costs are probable and reasonably estimable.

Employee Stock Options and Nonvested Common Stock (Restricted Stock) Awards: The Corporation uses the intrinsic value method to account for employee stock options. Because the exercise prices of employee stock options equal or exceed the market price of the stock on the date of grant, the Corporation does not recognize compensation expense. The following pro forma financial information presents the effect on net income and earnings per share as if the Corporation used the fair value method. The Corporation records compensation expense for non-vested common stock awards ratably over the vesting period.

Millions of dollars, except per share data	**2003**	2002	2001
Net income (loss)	**$ 643**	$ (218)	$ 914
Add stock-based employee compensation expense included in net income, net of taxes	**7**	5	8
Less total stock-based employee compensation expense determined using the fair value method, net of taxes	**(8)**	(19)	(22)
Pro forma net income (loss)	**$ 642**	$ (232)	$ 900
Net income (loss) per share as reported			
Basic	**$7.19**	$(2.48)	$10.38
Diluted	**7.11**	(2.48)	10.25
Pro forma net income (loss) per share			
Basic	**$7.19**	$(2.63)	$10.23
Diluted	**7.11**	(2.63)	10.10

Foreign Currency Translation: The U.S. dollar is the functional currency (primary currency in which business is conducted) for most foreign operations. For these operations, adjustments resulting from translating foreign currency assets and liabilities into U.S. dollars are recorded in income. For operations that use the local currency as the functional currency, adjustments resulting from translating foreign functional currency assets and liabilities into U.S. dollars are recorded in a separate component of stockholders' equity entitled accumulated other comprehensive income. Gains or losses resulting from transactions in other than the functional currency are reflected in net income.

Hedging: The Corporation uses futures, forwards, options and swaps, individually or in combination, to reduce the effects of fluctuations in crude oil, natural gas and refined product selling prices. The Corporation also uses derivatives in its energy marketing activities to fix the purchase prices of commodities to be sold under fixed-price contracts. Related hedge gains or losses are an integral part of the selling or purchase prices. Generally, these derivatives are designated as hedges of expected future cash flows or forecasted transactions (cash flow hedges), and the changes in fair value are recorded in accumulated other comprehensive income. These transactions meet the requirements for hedge accounting, including correlation. The Corporation reclassifies hedging gains and losses included in accumulated other comprehensive income to earnings at the time the hedged transactions are recognized. The ineffective portion of hedges is included in current earnings. The Corporation's remaining derivatives, including foreign currency contracts, are not designated as hedges and the change in fair value is included in income currently.

Trading: Derivatives (futures, forwards, options and swaps) used in energy trading activities are marked to market, with net gains and losses recorded in operating revenue. Gains or losses from the sale of physical products are recorded at the time of sale.

2. ITEMS AFFECTING INCOME FROM CONTINUING OPERATIONS

2003: The Corporation recorded a pre-tax charge of $58 million for premiums paid on the repurchase of bonds. This amount included premiums on bonds repurchased with proceeds of the fourth quarter preferred stock offering. The repurchased bonds included notes due in 2005 and 2007 assumed from Triton Energy at the time of the acquisition. This charge is reflected in non-operating income (expense) in the income statement.

The Corporation recorded expense of $53 million, before income taxes, for accrued severance and London office lease costs in exploration and production operations. Of this amount, $32 million relates to leased office space and the remainder relates to severance for positions that were eliminated in London, Aberdeen and Houston. Over 700 employee and contractor positions have been or will be eliminated or transferred to other operators. Approximately 240 employees are receiving severance, $15 million of which has been paid. The remainder is expected to be paid in 2004. The estimated annual savings from this cost reduction initiative is approximately $50 million before income taxes. The Corporation anticipates realizing approximately sixty percent of the savings in 2004 and the full amount in 2005 and beyond. The 2003 expense is reflected principally in general and administrative expense in the income statement.

Exploration and production earnings in 2003 include income tax benefits of $30 million reflecting the recognition of certain prior year foreign exploration expenses for United States income tax purposes. In addition, the Corporation recorded a pre-tax gain of $47 million from the sale of its 1.5% interest in the Trans-Alaska Pipeline System. A pre-tax loss of $9 million was recorded in refining and marketing earnings as a result of the sale of a shipping joint venture. Gains and losses on asset sales are reflected in non-operating income (expense) in the income statement.

2002: The Corporation recorded a pre-tax impairment charge of $706 million relating to the Ceiba field in Equatorial Guinea. The charge resulted from a reduction in probable reserves of approximately 12% of total field reserves, as well as the additional development costs of producing these reserves over a longer field life. Fair value was determined by discounting anticipated future net cash flows. Discounted cash flows were less than the book value of the field, which included allocated purchase price from the Triton acquisition. The Corporation also recorded a pre-tax impairment charge of $318 million to reduce the carrying value of oil and gas properties located primarily in the Main Pass/Breton Sound area of the Gulf of Mexico. Most of these properties were obtained in the 2001 LLOG acquisition and consisted of producing oil and gas fields with proved and probable reserves and exploration acreage. This charge principally reflects reduced reserve estimates on these fields resulting from unfavorable production performance. The fair values of producing properties were determined by using discounted cash flows. Exploration properties were evaluated by using results of drilling and production data from nearby fields and seismic data for these and other properties in the area. The pre-tax amounts of these charges were recorded in the caption asset impairments in the income statement.

During 2002, the Corporation completed the sale of six United States flag vessels for $161 million in cash and a note for $29 million. The sale resulted in a pre-tax gain of $102 million. The Corporation has agreed to support the buyer's charter rate for these vessels for up to five years. A pre-tax gain of $50 million was deferred as part of the sale transaction to reflect potential obligations of the support agreement. The support agreement requires that, if the actual contracted rate for the charter of a vessel is less than the stipulated charter rate in the agreement, the Corporation pays to the buyer the difference between the contracted rate and the stipulated rate. If the actual contracted rate exceeds the stipulated rate, the buyer must apply such amount to reimburse the Corporation for any payments made by the Corporation up to that date. At January 1, 2003, the charter support reserve was $48 million. During 2003, the Corporation paid $5 million of charter support. Based on contractual long-term charter rates and estimates of future charter rates, the Corporation lowered the estimated charter support reserve by $11 million. While the Corporation's eventual obligations under the support agreement could exceed the amount of the deferred gain, based on current estimates, the remaining amount recorded at December 31, 2003, $32 million, is appropriate.

Pre-tax net gains of $41 million were recorded during 2002 from sales of oil and gas producing properties in the United States, United Kingdom and Azerbaijan and the Corporation's energy marketing business in the United Kingdom.

The sale of the six United States flag vessels related to the refining and marketing segment and the remaining 2002 asset sales related to exploration and production activities. The pre-tax amounts of these asset sales are recorded in non-operating income in the income statement.

The United Kingdom government enacted a 10% supplementary tax on profits from oil and gas production in 2002. As a result of this tax law change, the Corporation recorded a one-time provision for deferred taxes of $43 million to increase the deferred tax liability on its balance sheet.

In 2002, the Corporation recorded a pre-tax charge of $22 million for the write-off of intangible assets in its U.S. energy marketing business. In addition, accrued severance of $13 million was recorded for cost reduction initiatives in refining and marketing, principally in energy marketing. Approximately 165 positions were eliminated and an office was closed. The estimated annual savings from the staff reduction is $15 million before tax. The accrued severance was paid prior to December 31, 2003.

2001: The Corporation recorded a pre-tax charge of $29 million for estimated losses due to the bankruptcy of certain subsidiaries of Enron Corporation. The charge reflected losses on less than 10% of the Corporation's crude oil and natural gas hedges.

The Corporation recorded a pre-tax charge of $18 million for severance expenses resulting from cost reduction initiatives, all of which has been paid. The cost reduction program reflected the elimination of approximately 150 positions, principally in exploration and production operations. Substantially all of the pre-tax cost of these items are reflected in general and administrative expense in the income statement.

3. DISCONTINUED OPERATIONS

In 2003, the Corporation took initiatives to reshape its portfolio of exploration and production assets to reduce costs, lengthen reserve lives, provide capital for investment and reduce debt.

In the first quarter of 2003, the Corporation exchanged its crude oil producing properties in Colombia (acquired in 2001 as part of the Triton acquisition), plus $10 million in cash, for an additional 25% interest in natural gas reserves in the joint development area of Malaysia and Thailand. The exchange resulted in a charge to income of $51 million before income taxes, which the Corporation reported as a loss from discontinued operations in the first quarter of 2003. The loss on this exchange included a $43 million pre-tax adjustment of the book value of the Colombian assets to fair value resulting primarily from a revision in crude oil reserves. The loss also included a $26 million charge from the recognition in earnings of the value of related hedge contracts at the time of the exchange. These items were partially offset by pre-tax earnings of $18 million in Colombia prior to the exchange.

In this exchange transaction, the Corporation acquired the 50% interest in a corporate joint venture that it did not already own. Prior to the exchange, the Corporation accounted for its 50% interest in the corporate joint venture using the equity method. Because of the exchange, the joint venture became a wholly owned subsidiary. Consequently, the Corporation has consolidated this subsidiary, which holds a 50% interest in a production sharing contract with natural gas reserves in the joint development area of Malaysia and Thailand. At the time of the exchange, the exploration and production segment included the net book value of fixed assets in Colombia of $670 million ($685 million at December 31, 2002) and a related deferred income tax liability of $142 million ($145 million at December 31, 2002).

In the second quarter of 2003, the Corporation sold producing properties in the Gulf of Mexico shelf, the Jabung Field in Indonesia and several small United Kingdom fields. The aggregate proceeds from these sales were $445 million and the pre-tax gain from disposition was $248 million. With respect to the assets sold in the second quarter of 2003, the net book value of fixed assets at the time of sale was approximately $295 million ($275 million at December 31, 2002) and the related dismantlement and deferred tax liabilities were approximately $160 million ($170 million at December 31, 2002).

Sales and other operating revenues (net of intercompany sales) from discontinued operations were $97 million in 2003, $381 million in 2002 and $361 million in 2001. Pretax operating profit for the same periods was $82 million, $14 million and $120 million, respectively. Income tax expense (benefit) was $29 million, $(13) million and $22 million for the same periods. The net production from fields accounted for as discontinued operations in 2003 at the time of disposition was approximately 45,000 barrels of oil equivalent per day.

4. ACCOUNTING CHANGE

On January 1, 2003, the Corporation changed its method of accounting for asset retirement obligations as required by FAS No. 143, *Accounting for Asset Retirement Obligations.* Previously, the Corporation had accrued the estimated costs of dismantlement, restoration and abandonment, less estimated salvage values, of offshore oil and gas production platforms and pipelines using the units-of-production method. This cost was reported as a component of depreciation expense and accumulated depreciation. Using the new accounting method required by FAS No. 143, the Corporation now recognizes a liability for the fair value of legally required asset retirement obligations associated with long-lived assets in the period in which the retirement obligations are incurred. The Corporation capitalizes the associated asset retirement costs as part of the carrying amount of the long-lived assets.

The cumulative effect of this change on prior years resulted in a credit to income of $7 million or $.07 per share, basic and diluted. The cumulative effect is included in income for the year ended December 31, 2003. The effect of the change on the year 2003 was to increase income before the cumulative effect of the accounting change by $3 million, after-tax ($.03 per share diluted). Assuming the accounting change had been applied retroactively to January 1, 2001 (rather than January 1, 2003), there would not have been a material change in income from continuing operations and net income in 2002 and 2001.

The following table describes changes to the Corporation's asset retirement obligations:

Millions of dollars	**2003**
Asset retirement obligations at	
January 1	**$ 556**
Liabilities incurred	**15**
Liabilities settled or disposed of	**(173)**
Accretion expense	**28**
Revisions	**25**
Foreign currency translation	**11**
Asset retirement obligations at	
December 31	**$ 462**

If FAS No. 143 had been applied beginning January 1, 2002 (rather than at January 1, 2003), the pro forma liability for asset retirement obligations at that date would have been $537 million.

The Corporation has adopted Emerging Issues Task Force abstract 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.* In accordance with EITF 02-3, the Corporation began accounting for trading inventory purchased after October 25, 2002 at the lower of cost or market. Inventory purchased prior to this date was marked-to-market with changes reflected in income currently. Beginning January 1, 2003, the Corporation accounted for all trading inventory at the lower of cost or market. This accounting change did not have a material effect on the Corporation's income or financial position.

The oil and gas industry is currently discussing the appropriate balance sheet classification of oil and gas mineral rights held by lease or contract. The Corporation classifies these assets as property, plant and equipment in accordance with its interpretation of FAS No. 19 and common industry practice. There is also a view that these mineral rights are intangible assets as defined in FAS No. 141, *Business Combinations*, and, therefore, should be classified separately on the balance sheet as intangible assets. If the accounting for mineral rights held by lease or contract is ultimately changed, the Corporation believes that any such reclassification of mineral rights could amount to approximately $2.3 billion at December 31, 2003, and $2.2 billion at December 31, 2002, if the Corporation is required to include the purchase price allocated to hydrocarbon reserves obtained in acquisitions of oil and gas properties. The determination of this amount is based on the Corporation's current understanding of this evolving issue and how the provisions of FAS No. 141 might be applied to oil and gas mineral rights. If mineral rights are reclassified to intangible assets, FAS No. 142, *Goodwill and Other Intangible Assets,* will require additional disclosures in the financial statement footnotes. This potential balance sheet reclassification would not affect results of operations or cash flows.

5. ACQUISITION OF TRITON ENERGY LIMITED

In 2001, the Corporation acquired 100% of the outstanding ordinary shares of Triton Energy Limited, an international oil and gas exploration and production company. The Corporation's consolidated financial statements include Triton's results of operations from August 14, 2001. The purchase price resulted in the recognition of goodwill of $977 million. Factors contributing to the recognition of goodwill included the strategic value of expanding global operations to access new growth areas outside of the United States and the North Sea, obtaining critical mass in Africa and Southeast Asia, and synergies, including cost savings, improved processes and portfolio high grading opportunities. The goodwill is assigned to the exploration and production reporting unit and is not deductible for income tax purposes.

The following 2001 pro forma results of operations present information as if the Triton acquisition occurred at the beginning of 2001:

Millions of dollars, except per share data	
Pro forma revenue	$13,936
Pro forma income	$ 914
Pro forma earnings per share	
Basic	$ 10.38
Diluted	$ 10.25

6. INVENTORIES

Inventories at December 31 are as follows:

Millions of dollars	**2003**	2002
Crude oil and other charge stocks	**$ 138**	$ 99
Refined and other finished products	**567**	497
Less: LIFO adjustment	**(293)**	(261)
	412	335
Materials and supplies	**167**	157
Total	**$ 579**	$ 492

7. REFINING JOINT VENTURE

The Corporation has an investment in HOVENSA L.L.C., a 50% joint venture with Petroleos de Venezuela, S.A. (PDVSA). HOVENSA owns and operates a refinery in the Virgin Islands, previously wholly-owned by the Corporation.

The Corporation accounts for its investment in HOVENSA using the equity method. Summarized financial information for HOVENSA as of December 31, 2003, 2002 and 2001 and for the years then ended follows:

Millions of dollars	**2003**	2002	2001
Summarized Balance Sheet At December 31			
Cash and cash equivalents	**$ 341**	$ 11	$ 25
Other current assets	**541**	509	466
Net fixed assets	**1,818**	1,895	1,846
Other assets	**37**	40	35
Current liabilities	**(441)**	(335)	(294)
Long-term debt	**(392)**	(467)	(365)
Deferred liabilities and credits	**(56)**	(45)	(23)
Partners' equity	**$1,848**	$ 1,608	$ 1,690
Summarized Income Statement For the years ended December 31			
Total revenues	**$5,451**	$ 3,783	$ 4,209
Costs and expenses	**(5,212)**	(3,872)	(4,089)
Net income (loss)*	**$ 239**	$ (89)	$ 120

**The Corporation's share of HOVENSA's income was $117 million in 2003 and $58 million in 2001. The Corporation's share of the 2002 loss was $47 million. The Corporation's share of HOVENSA's undistributed income aggregated $240 million at December 31, 2003.*

The Corporation has agreed to purchase 50% of HOVENSA's production of refined products at market prices, after sales by HOVENSA to unaffiliated parties. Such purchases amounted to approximately $2,040 million during 2003, $1,280 million during 2002 and $1,500 million during 2001. The Corporation sold crude oil to HOVENSA for approximately $410 million during 2003, $80 million during 2002 and $110 million during 2001. In addition, the Corporation billed HOVENSA freight charter costs of $59 million during 2003, $20 million during 2002 and $55 million during 2001.

The Corporation guarantees the payment of up to 50% of the value of HOVENSA's crude oil purchases from suppliers other than PDVSA. At December 31, 2003, this amount was $134 million. This amount fluctuates based on the volume of crude oil purchased and the related crude oil prices. In addition, the Corporation has agreed to provide funding to the extent HOVENSA does not have funds to meet its senior debt obligations up to a maximum of $40 million.

At formation of the joint venture, PDVSA V.I., a wholly-owned subsidiary of PDVSA, purchased a 50% interest in the fixed assets of the Corporation's Virgin Islands refinery for $62.5 million in cash and a 10-year note from PDVSA V.I. for $562.5 million bearing interest at 8.46% per annum and requiring principal payments over its term. At December 31, 2003 and December 31, 2002, the principal balance of the note was $334 million and $395 million, respectively.

8. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment at December 31 consists of the following:

Millions of dollars	**2003**	2002
Exploration and production		
Unproved properties	**$ 950**	$ 1,020
Proved properties	**2,634**	2,843
Wells, equipment and related facilities	**11,030**	10,836
Refining and marketing	**1,486**	1,450
Total — at cost	**16,100**	16,149
Less reserves for depreciation, depletion, amortization and lease impairment	**8,122**	9,117
Property, plant and equipment, net	**$ 7,978**	$ 7,032

During 2003, the Corporation recorded non-cash additions to fixed assets of $1,340 million. Of this total, $485 million related to assets that were previously accounted for as an equity investment in a company that holds natural gas reserves in Malaysia and Thailand. The remaining $855 million resulted from asset exchanges. The Corporation also recorded deferred income tax liabilities of $105 million related to the asset exchanges. The assets and liabilities relinquished in these exchanges included fixed assets of approximately $770 million, an additional equity investment of $145 million and deferred income tax liabilities of $145 million.

9. SHORT-TERM NOTES AND RELATED LINES OF CREDIT

The Corporation has no short-term notes at December 31, 2003. Short-term notes payable to banks at December 31, 2002 amounted to $2 million, bearing interest at a weighted average rate of 1.4%. At December 31, 2003, the Corporation has uncommitted arrangements with banks for unused lines of credit aggregating $206 million.

10. LONG-TERM DEBT

Long-term debt at December 31 consists of the following:

Millions of dollars	**2003**	2002
Fixed rate debentures, weighted average rate 7.2%, due through 2033	**$3,222**	$4,237
Pollution Control Revenue Bonds, weighted average rate 6.5%, due through 2032	**53**	53
Fixed rate notes, payable principally to insurance companies, weighted average rate 8.4%, due through 2014	**450**	450
Project lease financing, weighted average rate 5.1%, due through 2014	**164**	169
Capitalized lease obligations, weighted average rate 6.4%, due through 2009	**48**	56
6.1% Marine Terminal Revenue Bonds—Series 1994—City of Valdez, Alaska	**—**	20
Other loans, weighted average rate 9.3%, due through 2019	**4**	5
	3,941	4,990
Less amount included in current maturities	**73**	14
Total	**$3,868**	$4,976

The aggregate long-term debt maturing during the next five years is as follows (in millions): 2004—$73 (included in current liabilities); 2005—$60; 2006—$88; 2007—$212 and 2008—$129.

The Corporation's long-term debt agreements contain restrictions on the amount of total borrowings and cash dividends allowed. At December 31, 2003, the Corporation is permitted to borrow an additional $5 billion for the construction or acquisition of assets. At year-end, the amount that can be borrowed for the payment of dividends is $1.9 billion.

During 2003, the Corporation repurchased $1,015 million of fixed rate debentures consisting of most of the Corporation's 5.3% and 5.9% notes due in 2004 and 2006, respectively, as well as notes due in 2005 and 2007 assumed from Triton at the time of the acquisition. At December 31, 2003, the Corporation's public fixed rate debentures have a face value of $3,237 million ($3,222 million net of unamortized discount). Borrowings are due commencing in 2004 and extend through 2033. Interest rates on the debentures range from 5.3% to 7.9% and have a weighted average rate of 7.2%.

In connection with the sale of the Corporation's interest in the Trans Alaska Pipeline in January 2003, $20 million of Marine Terminal Revenue Bonds were assumed by the purchaser.

The Corporation has a $1.5 billion revolving credit agreement, which was unutilized at December 31, 2003 and expires in January 2006. Because of a credit downgrade in February 2004, borrowings under the facility currently would bear interest at 1.125% above the London Interbank Offered Rate. A facility fee of .375% per annum is currently payable on the amount of the credit line. At December 31, 2003, the interest rate was .725% above the London Interbank Offered Rate and the facility fee was .15%.

In 2003, 2002 and 2001, the Corporation capitalized interest of $41 million, $101 million and $44 million, respectively, on major development projects. The total amount of interest paid (net of amounts capitalized), principally on short-term and long-term debt, in 2003, 2002 and 2001 was $313 million, $274 million and $121 million, respectively.

11. STOCK BASED COMPENSATION PLANS

The Corporation has outstanding stock options and nonvested common stock (restricted stock) under its Amended and Restated 1995 Long-Term Incentive Plan. Generally, stock options vest one year from the date of grant and the exercise price equals or exceeds the market price on the date of grant. Outstanding nonvested common stock generally vests five years from the date of grant.

The Corporation's stock option activity in 2003, 2002 and 2001 consisted of the following:

	Options (thousands)	Weighted-average exercise price per share
Outstanding at January 1, 2001	4,295	$57.47
Granted	1,674	60.91
Exercised	(1,053)	56.28
Forfeited	(42)	61.79
Outstanding at December 31, 2001	4,874	58.87
Granted	46	66.45
Exercised	(492)	57.81
Forfeited	(53)	59.79
Outstanding at December 31, 2002	**4,375**	**59.06**
Granted	**65**	**47.07**
Forfeited	**(283)**	**64.08**
Outstanding at December 31, 2003	**4,157**	**$58.54**
Exercisable at December 31, 2001	3,216	$57.85
Exercisable at December 31, 2002	4,329	58.99
Exercisable at December 31, 2003	**4,092**	**58.72**

Exercise prices for employee stock options at December 31, 2003 ranged from $45.76 to $84.61 per share. The weighted-average remaining contractual life of employee stock options is 6 years.

The Corporation uses the Black-Scholes model to estimate the fair value of employee stock options for pro forma disclosure of the effects on net income and earnings per share. The Corporation used the following weighted-average assumptions in the Black-Scholes model for 2003, 2002 and 2001, respectively: risk-free interest rates of 3.6%, 4.2% and 4.1%; expected stock price volatility of .288, .262 and .244; dividend yield of 2.6%, 1.9% and 2.0%; and an expected life of seven years. The Corporation's net income would have been reduced by approximately $1 million in 2003 and $14 million in 2002 and 2001 if option expenses were recorded using the fair value method.

The weighted-average fair value per share of options granted for which the exercise price equaled the market price on the date of grant were $12.60 in 2003, $19.63 in 2002 and $16.20 in 2001.

Total compensation expense for nonvested common stock was $11 million in 2003, $7 million in 2002 and $12 million in 2001. Awards of nonvested common stock were as follows:

	Shares of nonvested common stock awarded (thousands)	Weighted-average price on date of grant
Granted in 2001	108	$ 67.25
Granted in 2002	21	66.29
Granted in 2003	**765**	**46.73**

At December 31, 2003, the number of common shares reserved for issuance under the 1995 Long-Term Incentive Plan is as follows (in thousands):

Future awards	479
Stock options outstanding	4,157
Stock appreciation rights	4
Total	4,640

12. FOREIGN CURRENCY TRANSLATION

Foreign currency gains (losses) from continuing operations before income taxes amounted to $(6) million in 2003, $26 million in 2002 and $(22) million in 2001.

The balances in accumulated other comprehensive income related to foreign currency translation were reductions in stockholders' equity of $94 million at December 31, 2003 and $107 million at December 31, 2002.

13. PENSION PLANS

The Corporation has funded noncontributory defined benefit pension plans for substantially all of its employees. In addition, the Corporation has an unfunded supplemental pension plan covering certain employees. The unfunded supplemental pension plan provides for incremental pension payments from the Corporation's funds so that total pension payments equal amounts that would have been payable from the Corporation's principal pension plans, were it not for limitations imposed by income tax regulations. The plans provide defined benefits based on years of service and final average salary. The Corporation uses December 31 as the measurement date for its plans.

The following table reconciles the projected benefit obligation and the fair value of plan assets and shows the funded status of the pension plans:

	Funded Pension Benefits		*Unfunded Pension Benefits*	
Millions of dollars	**2003**	2002	**2003**	2002
Reconciliation of projected benefit obligation				
Balance at January 1	**$ 721**	$ 623	**$ 61**	$ 59
Service cost	**24**	23	**3**	2
Interest cost	**47**	44	**4**	4
Amendments	**—**	—	**—**	4
Actuarial loss	**57**	60	**3**	1
Benefit payments	**(32)**	(29)	**(6)**	(9)
Balance at December 31	**817**	721	**65**	61
Reconciliation of fair value of plan assets				
Balance at January 1	**487**	495	**—**	—
Actual return on plan assets	**104**	(42)	**—**	—
Employer contributions	**67**	63	**6**	9
Benefit payments	**(32)**	(29)	**(6)**	(9)
Balance at December 31	**626**	487	**—**	—
Funded status (plan assets less than benefit obligations)	**(191)**	(234)	**(65)***	(61)*
Unrecognized net actuarial loss	**190**	214	**18**	15
Unrecognized prior service cost	**3**	5	**3**	3
Net amount recognized	**$ 2**	$ (15)	**$(44)**	$(43)

**The trust established by the Corporation to fund the supplemental plan held assets valued at $40 million at December 31, 2003 and $26 million at December 31, 2002.*

Amounts recognized in the consolidated balance sheet at December 31 consist of the following:

	Funded Pension Benefits		*Unfunded Pension Benefits*	
Millions of dollars	**2003**	2002	**2003**	2002
Accrued benefit liability	**$(106)**	$(130)	**$(53)**	$(44)
Intangible assets	**3**	5	**3**	1
Accumulated other comprehensive income*	**105**	110	**6**	—
Net amount recognized	**$ 2**	$ (15)	**$(44)**	$(43)

**Amount included in other comprehensive income after income taxes was $73 million at December 31, 2003 and $72 million at December 31, 2002.*

The accumulated benefit obligation for the funded defined benefit pension plans was $733 million at December 31, 2003 and $639 million at December 31, 2002. The accumulated benefit obligation for the unfunded defined benefit pension plan was $53 million at December 31, 2003 and $44 million at December 31, 2002.

All pension plans had accumulated benefit obligations in excess of plan assets at December 31, 2003 and 2002.

Components of funded and unfunded pension expense consisted of the following:

Millions of dollars	**2003**	2002	2001
Service cost	**$ 27**	$ 25	$ 21
Interest cost	**51**	49	45
Expected return on plan assets	**(44)**	(44)	(48)
Amortization of prior service cost	**2**	2	3
Amortization of net loss	**19**	5	1
Net periodic benefit cost	**$ 55**	$ 37	$ 22
Increase in minimum liability included in other comprehensive income	**$ 1**	$110	$ —

Prior service costs and gains and losses in excess of 10% of the greater of the benefit obligation or the market value of assets are amortized over the average remaining service period of active employees.

The weighted-average actuarial assumptions used by the Corporation's funded and unfunded pension plans were as follows:

	2003	2002	2001
Weighted-average assumptions used to determine benefit obligations at December 31			
Discount rate	**6.2%**	6.6%	7.0%
Rate of compensation increase	**4.5**	4.4	4.5
Weighted-average assumptions used to determine net cost for years ended December 31			
Discount rate	**6.6%**	7.0%	7.0%
Expected return on plan assets	**8.5**	9.0	9.0
Rate of compensation increase	**4.4**	4.5	4.5

The assumed long-term rate of return on assets is based on historical, long-term returns of the plan, adjusted downward to reflect lower prevailing interest rates. The assumed long-term rate of return is less than the actual return for the year ended December 31, 2003.

The Corporation's funded pension plan assets by asset category are as follows:

	At December 31	
Asset Category	**2003**	2002
Equity securities	**57%**	57%
Debt securities	**43**	43
Total	**100%**	100%

The target investment allocations for the plan assets are 55% equity securities and 45% debt securities. Asset allocations are rebalanced on a regular basis throughout the year to bring assets to within a 2—3% range of target levels. Target allocations take into account analyses performed to optimize long term risk and return relationships. All assets are highly liquid and can be readily adjusted to provide liquidity for current benefit payment requirements.

The Corporation has budgeted contributions of $82 million to its funded pension plans in 2004. The Corporation also has budgeted contributions of $20 million to the trust established for the unfunded plan.

Estimated future pension benefit payments for the funded and unfunded plans, which reflect expected future service, are as follows:

Millions of dollars	
2004	$ 43
2005	38
2006	39
2007	41
2008	43
Years 2009 to 2013	258

14. PROVISION FOR INCOME TAXES

The provision for income taxes on income from continuing operations consisted of:

Millions of dollars	**2003**	2002	2001
United States Federal			
Current	**$(180)**	$ 30	$ 57
Deferred	**78**	(158)	50
State	**(13)**	5	27
	(115)	(123)	134
Foreign			
Current	**431**	401	355
Deferred	**(2)**	(141)	13
	429	260	368
Adjustment of deferred tax liability for foreign income tax rate change	**—**	43	—
Total provision for income taxes on continuing operations	**$ 314**(a)	$ 180	$502(b)

(a) *Includes benefit of $30 million relating to certain prior year foreign exploration expenses.*
(b) *Includes benefit of $48 million relating to prior year refunds of United Kingdom Advance Corporation Taxes and deductions for exploratory drilling.*

Income (loss) from continuing operations before income taxes consisted of the following:

Millions of dollars	**2003**	2002	2001
United States	**$ (245)**(a)	$(378)	$ 330
Foreign(b)	**1,026**	313	988
Total income from continuing operations	**$ 781**	$ (65)	$1,318

(a) *Includes substantially all of the Corporation's interest expense and the results of hedging activities.*
(b) *Foreign income includes the Corporation's Virgin Islands, shipping and other operations located outside of the United States.*

Deferred income taxes arise from temporary differences between the tax bases of assets and liabilities and their recorded amounts in the financial statements. A summary of the components of deferred tax liabilities and assets at December 31 follows:

Millions of dollars	**2003**	2002
Deferred tax liabilities		
Fixed assets and investments	**$1,391**	$ 943
Foreign petroleum taxes	**281**	256
Other	**226**	138
Total deferred tax liabilities	**1,898**	1,337
Deferred tax assets		
Accrued liabilities	**209**	124
Dismantlement liability	**169**	—
Net operating loss carryforwards	**551**	543
Tax credit carryforwards	**155**	61
Other	**64**	33
Total deferred tax assets	**1,148**	761
Valuation allowance	**(93)**	(95)
Net deferred tax assets	**1,055**	666
Net deferred tax liabilities	**$ 843**	$ 671

The difference between the Corporation's effective income tax rate and the United States statutory rate is reconciled below:

	2003	2002	2001
United States statutory rate	**35.0%**	(35.0)%	35.0%
Effect of foreign operations, including foreign tax credits	**4.6**	321.5*	2.8
Loss on repurchase of bonds	**(.6)**	(15.4)	—
State income taxes, net of Federal income tax benefit	**(1.1)**	8.1	1.3
Prior year adjustments	**2.8**	(1.5)	(1.5)
Other	**(.4)**	(.1)	.5
Total	**40.3%**	277.6%	38.1%

**Reflects high effective tax rates in certain foreign jurisdictions, including special taxes in the United Kingdom and Norway, and losses in other jurisdictions which were benefited at lower rates.*

The Corporation has not recorded deferred income taxes applicable to undistributed earnings of foreign subsidiaries that are expected to be indefinitely reinvested in foreign operations. Undistributed earnings amounted to approximately $2.6 billion at December 31, 2003 and include amounts which, if remitted, would result in U.S. income taxes at less than the statutory rate, because of available foreign tax credits. If the earnings of such foreign subsidiaries were not indefinitely reinvested, a deferred tax liability of approximately $100 million would have been required.

For income tax reporting at December 31, 2003, the Corporation has alternative minimum tax credit carryforwards of approximately $120 million, which can be carried forward indefinitely. The Corporation also has approximately $35 million of general business credits. At December 31, 2003, the Corporation has a net operating loss carryforward in the United States of approximately $450 million. At December 31, 2003, a net operating loss carryforward of approximately $500 million is also available to offset the Corporation's share of HOVENSA joint venture income and to reduce taxes on interest from the PDVSA note. In addition, a foreign exploration and production subsidiary has a net operating loss carryforward of approximately $550 million.

Income taxes paid (net of refunds) in 2003, 2002 and 2001 amounted to $361 million, $410 million and $605 million, respectively.

15. STOCKHOLDERS' EQUITY AND NET INCOME PER SHARE

The weighted average number of common shares used in the basic and diluted earnings per share computations for each year are summarized below:

Thousands of shares	**2003**	2002	2001
Common shares—basic	**88,618**	88,187	88,031
Effect of dilutive securities			
Convertible preferred stock	**1,425**	—	205
Nonvested common stock	**290**	—	425
Stock options	**9**	—	468
Common shares—diluted	**90,342**	88,187	89,129

The table above excludes the effect of out-of-the-money options on 4,170,000 shares, 633,000 shares and 139,000 shares in 2003, 2002 and 2001, respectively. In 2002, the table also excludes the antidilutive effect of 461,000 non-vested common shares, 424,000 stock options and 205,000 shares of convertible preferred stock.

Earnings per share are as follows:

	2003	2002	2001
Basic			
Continuing operations	**$5.21**	$(2.78)	$ 9.26
Discontinued operations	**1.91**	.30	1.12
Cumulative effect of change in accounting	**.07**	—	—
Net income (loss)	**$7.19**	$(2.48)	$10.38
Diluted			
Continuing operations	**$5.17**	$(2.78)	$ 9.15
Discontinued operations	**1.87**	.30	1.10
Cumulative effect of change in accounting	**.07**	—	—
Net income (loss)	**$7.11**	$(2.48)	$10.25

In 2003, the Corporation issued 13,500,000 shares of 7% cumulative mandatory convertible preferred stock. Dividends are payable on March 1, June 1, September 1 and December 1 of each year. The cumulative mandatory convertible preferred shares have a liquidation preference of $675 million ($50 per share). Each cumulative mandatory convertible preferred share will automatically convert on December 1, 2006 into .8305 to 1.0299 shares of common stock, depending on the average closing price of the Corporation's common stock over a 20-day period before conversion. The Corporation has reserved 13,903,650 shares of common stock for the conversion of these preferred shares. Holders of the cumulative mandatory convertible preferred stock have the right to convert their shares at any time prior to December 1, 2006 at the rate of .8305 share of common stock for each preferred share converted. The cumulative mandatory convertible preferred shares do not have voting rights, except in certain limited circumstances.

16. LEASED ASSETS

The Corporation and certain of its subsidiaries lease gasoline stations, tankers, floating production systems, drilling rigs, office space and other assets for varying periods. At December 31, 2003, future minimum rental payments applicable to noncancelable leases with remaining terms of one year or more (other than oil and gas property leases) are as follows:

Millions of dollars	*Operating Leases*	*Capital Leases*
2004	$ 95	$13
2005	71	13
2006	71	13
2007	71	13
2008	71	2
Remaining years	924	1
Total minimum lease payments	1,303	55
Less: Imputed interest	—	7
Income from subleases	36	—
Net minimum lease payments	$1,267	$48
Capitalized lease obligations		
Current		$10
Long-term		38
Total		$48

Certain operating leases provide an option to purchase the related property at fixed prices.

Rental expense for all operating leases, other than rentals applicable to oil and gas property leases, was as follows:

Millions of dollars	**2003**	2002	2001
Total rental expense	**$190**	$160	$206
Less income from subleases	**52**	34	63
Net rental expense	**$138**	$126	$143

17. FINANCIAL INSTRUMENTS, NON-TRADING AND TRADING ACTIVITIES

On January 1, 2001, the Corporation adopted FAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* This statement requires that the Corporation recognize all derivatives on the balance sheet at fair value and establishes criteria for using derivatives as hedges.

The January 1, 2001 transition adjustment resulting from adopting FAS No. 133 was a cumulative increase in other comprehensive income of $100 million after income taxes ($145 million before income taxes). Substantially all of the transition adjustment resulted from crude oil and natural gas cash flow hedges. The transition adjustment did not have a material effect on net income or retained earnings.

Non-Trading: The Corporation uses futures, forwards, options and swaps, individually or in combination, to reduce the effects of fluctuations in crude oil, natural gas and refined product selling prices. The Corporation also uses derivatives in its energy marketing activities to fix the purchase prices of commodities to be sold under fixed-price contracts. Related hedge gains or losses are an integral part of the selling or purchase prices. Generally, these derivatives are designated as hedges of expected future cash flows or forecasted transactions (cash flow hedges), and the changes in fair value are recorded in other comprehensive income until the hedged transactions are recognized. The Corporation's use of fair value hedges is not material.

The Corporation reclassifies hedging gains and losses from accumulated other comprehensive income to earnings at the time the hedged transactions are recognized. Hedging decreased exploration and production results by $418 million before income taxes in 2003. Hedging increased exploration and production results before income taxes by $82 million in 2002 and $106 million in 2001 (including $82 million associated with the transition adjustment at the beginning of 2001). The ineffective portion of hedges is included in current earnings in cost of products sold. The amount of hedge ineffectiveness was not material during the years ended December 31, 2003, 2002 and 2001.

The Corporation produced 95 million barrels of crude oil and natural gas liquids and 249 million Mcf of natural gas in 2003. The Corporation's crude oil and natural gas hedging activities included commodity futures and swap contracts. At December 31, 2003, crude oil hedges maturing in 2004 and 2005 cover 93 million barrels of crude oil production (91 million barrels of crude oil at December 31, 2002). The Corporation has natural gas hedges maturing in 2004 covering 18 million Mcf of natural gas production in the United States at December 31, 2003 (35 million Mcf of natural gas at December 31, 2002).

Since the contracts described above are designated as hedges and correlate to price movements of crude oil and natural gas, any gains or losses resulting from market changes will be offset by losses or gains on the Corporation's production. At December 31, 2003, net after tax deferred losses in accumulated other comprehensive income from the Corporation's crude oil and natural gas hedging contracts expiring through 2005 were $229 million ($352 million before income taxes), including $196 million of unrealized losses. Of the net after tax deferred loss, $185 million matures during 2004. At December 31, 2002, net after-tax deferred losses were $91 million ($141 million before income taxes), including $71 million of unrealized losses.

In its energy marketing business, the Corporation has entered into cash flow hedges to fix the purchase prices of natural gas, heating oil, residual fuel oil and electricity. At December 31, 2003, the net after tax deferred gains in accumulated other comprehensive income from these contracts, expiring through 2007, were $45 million ($70 million before income taxes). Substantially all of the deferred gains will be recognized in 2004.

Commodity Trading: The Corporation, principally through a consolidated partnership, trades energy commodities, including futures, forwards, options and swaps, based on expectations of future market conditions. The Corporation's income before income taxes from trading activities, including its share of the earnings of the trading partnership amounted to $30 million in 2003, $6 million in 2002 and $72 million in 2001.

Other Financial Instruments: Foreign currency contracts are used to protect the Corporation from fluctuations in exchange rates. The Corporation enters into foreign currency contracts, which are not designated as hedges, and the change in fair value is included in income currently. The Corporation has $384 million of notional value foreign currency forward contracts maturing in 2004 and 2005 ($307 million at December 31, 2002). Notional amounts do not quantify risk or represent assets or liabilities of the Corporation, but are used in the calculation of cash settlements under the contracts. The fair values of the foreign currency forward contracts recorded by the Corporation were receivables of $40 million at December 31, 2003 and $18 million at December 31, 2002.

The Corporation also has $229 million in letters of credit outstanding at December 31, 2003 ($149 million at December 31, 2002). Of the total letters of credit outstanding at December 31, 2003, $7 million represents contingent liabilities; the remaining $222 million relates to liabilities recorded on the balance sheet.

Fair Value Disclosure: The Corporation estimates the fair value of its fixed-rate notes receivable and debt generally using discounted cash flow analysis based on current interest rates for instruments with similar maturities. Foreign currency exchange contracts are valued based on current termination values or quoted market prices of comparable contracts. The Corporation's valuation of commodity contracts considers quoted market prices where applicable. In the absence of quoted market prices, the Corporation values contracts at fair value considering time value, volatility of the underlying commodities and other factors.

The following table presents the year-end fair values of energy commodities and derivative financial instruments used in non-trading and trading activities:

Millions of dollars, asset (liability)	*Fair Value At Dec. 31*	
	2003	*2002*
Commodities	**$ —**	$ 27
Futures and forwards		
Assets	**219**	370
Liabilities	**(218)**	(378)
Options		
Held	**975**	65
Written	**(948)**	(27)
Swaps		
Assets	**1,157**	1,323
Liabilities	**(1,384)**	(1,394)

The carrying amounts of the Corporation's financial instruments and commodity contracts, including those used in the Corporation's non-trading and trading activities, generally approximate their fair values at December 31, 2003 and 2002, except as follows:

	2003		2002	
Millions of dollars, asset (liability)	*Balance Sheet Amount*	*Fair Value*	*Balance Sheet Amount*	*Fair Value*
Fixed-rate notes receivable	**$ 363**	**$ 355**	$ 424	$ 364
Fixed-rate debt	**(3,935)**	**(4,434)**	(4,984)	(5,561)

Credit Risks: The Corporation's financial instruments expose it to credit risks and may at times be concentrated with certain counterparties or groups of counterparties. The credit worthiness of counterparties is subject to continuing review and full performance is anticipated. The Corporation reduces its risk related to certain counterparties by using master netting agreements and requiring collateral, generally cash.

In its trading activities the Corporation has net receivables of $351 million at December 31, 2003, which are concentrated with counterparties as follows: domestic and foreign trading companies — 25%, gas and power companies — 25%, banks and major financial institutions — 22%, government entities — 15% and integrated energy companies — 7%.

18. GUARANTEES AND CONTINGENCIES

In the normal course of business, the Corporation provides guarantees principally for investees of the Corporation. These guarantees are contingent commitments that ensure performance for repayment of borrowings and other arrangements. The maximum potential amount of future payments that the Corporation could be required to make under its guarantees at December 31, 2003 is $99 million ($358 million at December 31, 2002). This amount includes the Corporation's guarantee of $40 million of the senior debt obligation of HOVENSA (see note 7). The remainder relates generally to a loan guarantee of a natural gas pipeline in which the Corporation owns a 5% interest. The amount of this guarantee declines over its term.

The Corporation is subject to contingent liabilities with respect to existing or potential claims, lawsuits and other proceedings. The Corporation considers these routine and incidental to its business and not material to its financial position or results of operations. The Corporation accrues liabilities when the future costs are probable and reasonably estimable.

19. SEGMENT INFORMATION

Financial information by major geographic area for each of the three years ended December 31, 2003 follows:

Millions of dollars	*United States*	*Europe*	*Africa, Asia and other*	*Consolidated*
2003				
Operating revenues	**$12,019**	**$1,694**	**$ 598**	**$14,311**
Property, plant and equipment (net)	**1,705**	**2,538**	**3,735**	**7,978**
2002				
Operating revenues	$ 8,684	$2,185	$ 682	$11,551
Property, plant and equipment (net)	1,770	2,327	2,935	7,032
2001				
Operating revenues	$ 9,663	$3,081	$ 308	$13,052
Property, plant and equipment (net)	2,469	2,322	3,374	8,165

The Corporation has two operating segments that comprise the structure used by senior management to make key operating decisions and assess performance. These are (1) exploration and production and (2) refining and marketing. Operating segments have not been aggregated. Exploration and production operations include the exploration for and the production, purchase, transportation and sale of crude oil and natural gas. Refining and marketing operations include the manufacture, purchase, transportation, trading and marketing of petroleum and other energy products.

19. SEGMENT INFORMATION (CONTINUED)

The following table presents financial data by operating segment for each of the three years ended December 31, 2003:

Millions of dollars	*Exploration and Production*	*Refining and Marketing*	*Corporate and Interest*	*Consolidated**
2003				
Operating revenues				
Total operating revenues	**$ 3,153**	**$11,473**	**$ 1**	
Less: Transfers between affiliates	**316**	**—**	**—**	
Operating revenues from unaffiliated customers	**$ 2,837**	**$11,473**	**$ 1**	**$14,311**
Income (loss) from continuing operations	**$ 414**	**$ 327**	**$(274)**	**$ 467**
Discontinued operations	**170**	**—**	**(1)**	**169**
Income from cumulative effect of accounting change	**7**	**—**	**—**	**7**
Net income (loss)	**$ 591**	**$ 327**	**$(275)**	**$ 643**
Earnings of equity affiliates	**$ 13**	**$ 125**	**$ —**	**$ 138**
Interest income	**10**	**34**	**2**	**46**
Interest expense	**—**	**—**	**293**	**293**
Depreciation, depletion, amortization and lease impairment	**1,063**	**54**	**1**	**1,118**
Provision (benefit) for income taxes	**363**	**126**	**(175)**	**314**
Investments in equity affiliates	**—**	**1,055**	**—**	**1,055**
Identifiable assets	**9,149**	**4,267**	**567**	**13,983**
Capital employed	**6,270**	**2,820**	**191**	**9,281**
Capital expenditures	**1,286**	**66**	**6**	**1,358**
2002				
Operating revenues				
Total operating revenues	$ 3,735	$ 8,351	$ 1	
Less: Transfers between affiliates	536	—	—	
Operating revenues from unaffiliated customers	$ 3,199	$ 8,351	$ 1	$11,551
Income (loss) from continuing operations	$ (102)	$ 85	$(228)	$ (245)
Discontinued operations	40	—	(13)	27
Net income (loss)	$ (62)	$ 85	$(241)	$ (218)
Earnings of equity affiliates	$ (4)	$ (38)	$ —	$ (42)
Interest income	5	38	1	44
Interest expense	—	—	256	256
Depreciation, depletion, amortization and lease impairment	1,103	55	1	1,159
Asset impairments	1,024	—	—	1,024
Provision (benefit) for income taxes	265	47	(132)	180
Investments in equity affiliates	617	1,001	—	1,618
Identifiable assets	8,392	4,218	652	13,262
Capital employed	6,657	2,465	118	9,240
Capital expenditures	1,404	123	7	1,534
2001				
Operating revenues				
Total operating revenues	$ 4,451	$ 9,454	$ 2	
Less: Transfers between affiliates	855	—	—	
Operating revenues from unaffiliated customers	$ 3,596	$ 9,454	$ 2	$13,052
Income (loss) from continuing operations	$ 796	$ 233	$(213)	$ 816
Discontinued operations	98	—	—	98
Net income (loss)	$ 894	$ 233	$(213)	$ 914
Earnings of equity affiliates	$ (2)	$ 54	$ —	$ 52
Interest income	6	45	8	59
Interest expense	—	—	194	194
Depreciation, depletion, amortization and lease impairment	818	51	2	871
Provision (benefit) for income taxes	506	65	(69)	502
Investments in equity affiliates	580	1,052	—	1,632
Identifiable assets	10,412	4,797	160	15,369
Capital employed	7,534	2,999	39	10,572
Capital expenditures	5,061	155	5	5,221

** After elimination of transactions between affiliates, which are valued at approximate market prices.*