Management's Discussion and Analysis of Results of Operations and Financial Condition

Executive Overview

The Corporation is a global integrated energy company that operates in two segments, exploration and production (E&P) and refining and marketing (R&M). The E&P segment explores for, produces and sells crude oil and natural gas. The R&M segment manufactures, trades and markets refined petroleum and other energy products.

The Corporation's long-term goal for the E&P segment is to generate profitable and sustainable growth by transitioning the asset portfolio to longer life, lower cost fields, bringing new field developments onstream and pursuing a focused, high impact exploration program. During the past three years the Corporation has reshaped its E&P asset portfolio by:

- Acquiring exploration, development and production assets in West Africa and Southeast Asia.
- Selling higher cost properties predominantly in the shallow water Gulf of Mexico and the North Sea.
- Exchanging interests in mature producing assets for increased interests in development stage assets in the joint development area of Malaysia and Thailand and deepwater Gulf of Mexico.

The asset sales and exchanges have reduced near-term production which increased unit operating costs. Production declined from 451,000 barrels of oil equivalent per day in 2002 to 373,000 barrels of oil equivalent per day in 2003. Over 60% of the reduction resulted from the absence of production from assets sold or exchanged. The remainder of the decrease was due to natural declines and poorer than expected performance of certain fields in the United States and Equatorial Guinea. Production is expected to decline in 2004 by approximately 13% due to the 2003 asset sales and swaps and natural declines in our remaining fields.

The Corporation is currently funding twelve development projects that are expected to provide over 100,000 barrels of oil equivalent per day of new production in 2006, offsetting natural declines in existing fields and providing net overall production growth. In addition, since 2002, the Corporation has participated in two deepwater Gulf of Mexico discoveries that may provide additional production beyond 2006. As a result of the development projects, the Corporation presently estimates that production will be slightly higher in 2005 than in 2004 and production will increase further in 2006. While the Corporation expects these developments to be completed as currently scheduled, development projects may be subject to unforeseen events, such as technical complexities, delays in governmental sanction and political instability.

The lower production in 2004 is not expected to result in higher 2004 unit operating costs due to cost reduction initiatives begun in 2003 and the portfolio rationalization. The Corporation believes these factors, plus increasing production from new developments, will reduce unit costs in the future.

The portfolio reshaping has reduced near-term cash flows from operations. In response, the Corporation has hedged approximately 70% and 45% of its 2004 and 2005 worldwide crude oil production to provide secure cash flow to fund the development projects. Upon completion of the projects, the Corporation expects the percentage of hedged volumes to decrease.

The R&M segment's financial results improved significantly in 2003, principally reflecting higher margins and increased sales volumes. The Corporation's strategic goals for R&M are to maximize financial returns from existing assets and to generate free cash flow. The Corporation may opportunistically add retail marketing sites in its East Coast marketing area.

The Corporation's liquidity and financial position were significantly improved in 2003. At December 31, 2002, the Corporation's debt was $5 billion and its debt to capitalization ratio was 54%. During 2003, the Corporation generated cash flow of $545 million from asset sales and $653 million from the issuance of mandatory convertible preferred stock. These actions, combined with additional free cash flow from profitable operations after funding capital expenditures, resulted in debt reduction of $1.1 billion. Year-end debt was $3.9 billion and the debt to capitalization ratio improved to 42.5%. The Corporation has $221 million of debt maturities over the next three years, and had $518 million of cash on hand at December 31, 2003.

Consolidated Results of Operations

Income from continuing operations was $467 million in 2003 compared with a loss of $245 million, including impairments, in 2002 and income of $816 million in 2001. Including income from discontinued operations, net income for 2003 was $643 million, compared with a net loss of $218 million in 2002 and net income of $914 million in 2001.

The after-tax results by major operating activity for 2003, 2002 and 2001 are summarized below:

Millions of dollars, except per share data	**2003**	2002	2001
Exploration and production	**$ 414**	$ (102)	$ 796
Refining and marketing	**327**	85	233
Corporate	**(101)**	(63)	(78)
Interest expense	**(173)**	(165)	(135)
Income (loss) from continuing operations	**467**	(245)	816
Discontinued operations			
Net gains from asset sales	**116**	—	—
Income from operations	**53**	27	98
Income from cumulative effect of accounting change	**7**	—	—
Net income (loss)	**$ 643**	$ (218)	$ 914
Income (loss) per share from continuing operations — diluted	**$5.17**	$(2.78)	$ 9.15
Net income (loss) per share — diluted	**$7.11**	$(2.48)	$10.25

In the discussion which follows, the financial effects of certain transactions are disclosed on an after-tax basis. Management reviews segment earnings on an after-tax basis and uses after-tax amounts in its review of variances in segment earnings. Management believes that after-tax amounts are a preferable method of explaining variances in earnings, since they show the entire effect of a transaction rather than only the pre-tax amount. After-tax amounts are determined by applying the appropriate income tax rate in each tax jurisdiction to pre-tax amounts.

The following items, on an after-tax basis, are included in income from continuing operations for the years 2003, 2002 and 2001:

Millions of dollars	**2003**	2002	2001
Premiums on bond repurchases	**$(34)**	$ (6)	$ —
Accrued severance and London office lease costs	**(32)**	—	(10)
United States income tax benefit	**30**	—	—
Net gains from asset sales	**11**	100	—
Asset impairments	**—**	(737)	—
Charge for increase in United Kingdom income tax rate	**—**	(43)	—
Reduction in carrying value of refining and marketing intangible assets and severance	**—**	(22)	(2)
Charge related to Enron bankruptcy	**—**	—	(19)
	$(25)	$(708)	$(31)

The items in the table above are explained on pages 18, 19 and 20. The pre-tax amounts are shown on pages 18 and 20.

Comparison of Results

Exploration and Production: After considering the exploration and production items in the preceding table (described on page 18), the remaining changes in exploration and production earnings are primarily attributable to changes in selling prices, production volumes and operating costs and exploration expenses, as discussed below.

Selling prices: Higher average selling prices of crude oil, natural gas liquids and natural gas increased exploration and production revenues from continuing operations by approximately $170 million in 2003 compared with 2002. In 2002, the change in average selling prices did not significantly affect revenues compared with 2001. The Corporation's average selling prices from continuing operations, including the effects of hedging, were as follows:

	2003	2002	2001
Crude oil (per barrel)			
United States	**$24.23**	$24.04	$23.38
Foreign	**24.93**	24.69	24.50
Natural gas liquids (per barrel)			
United States	**23.74**	16.12	18.76
Foreign	**24.09**	19.09	18.99
Natural gas (per Mcf)			
United States	**4.02**	3.72	4.02
Foreign	**3.01**	2.26	2.55

Production volumes: Lower crude oil and natural gas production volumes reduced exploration and production revenues from continuing operations in 2003 compared with 2002 by $425 million. In 2002, crude oil production was higher than in 2001 and natural gas production was lower. The net effect of these volume changes was an increase in revenues of $100 million. The Corporation's net daily worldwide production was as follows:

	2003	2002	2001
Crude oil			
(thousands of barrels per day)			
United States	**44**	54	63
Foreign	**195**	250	212
Total	**239**	304	275
Natural gas liquids			
(thousands of barrels per day)			
United States	**11**	12	14
Foreign	**9**	9	9
Total	**20**	21	23
Natural gas			
(thousands of Mcf per day)			
United States	**253**	373	424
Foreign	**430**	381	388
Total	**683**	754	812
Barrels of oil equivalent*			
(thousands of barrels per day)	**373**	451	433
Barrel of oil equivalent production			
related to discontinued operations	**13**	51	45

**Reflects natural gas production converted on the basis of relative energy content (six Mcf equals one barrel).*

The Corporation's oil and gas production, on a barrel of oil equivalent basis, decreased to 373,000 barrels per day in 2003 from 451,000 barrels per day in 2002. Approximately 60% of this decline was due to asset sales and exchanges. The remainder was principally due to natural decline, disappointing results from fields acquired in the United States in 2001 and reduced production from the Ceiba Field in Equatorial Guinea. The Corporation anticipates that its 2004 production will be approximately 13% below 2003 production of 373,000 barrels of oil equivalent per day. Approximately 16,000 barrels per day of the expected decrease is due to asset sales and exchanges in 2003 and the remainder is principally due to natural decline.

Operating costs and exploration expenses: Operating costs and exploration expenses from continuing operations increased by approximately $70 million and $330 million in 2003 and 2002 compared with the corresponding amounts in the prior years.

Production expenses increased in 2003 primarily due to the weakening of the U.S. dollar, which increased costs incurred in foreign currencies and resulted in higher expenses than in prior years. Production expenses in 2003 also reflect higher employee benefit, transportation and maintenance costs. Production expenses in 2002 were higher than in 2001 due to increased production from higher cost fields, workovers and other maintenance, and higher production volumes. Depreciation, depletion and amortization charges were lower in 2003 than in 2002, reflecting decreased production volumes and lower depreciable costs resulting from impairments in 2002. Depreciation and related charges were higher in 2002 compared to 2001, due to higher unit costs from amortization of the purchase prices of fields in Equatorial Guinea, Colombia and the United States and increased production volumes. Exploration expense was higher in 2003, reflecting increased activity in the United States and Equatorial Guinea, as well as additional lease cost amortization. Exploration expense decreased in 2002 compared with 2001, principally reflecting improved drilling results.

The Corporation's total unit cost per barrel of oil equivalent produced increased in 2003 and 2002 compared with 2001. Unit cost per barrel includes production expense, depreciation, depletion and amortization, exploration expense and administrative costs. Unit costs per barrel totaled $17.32 in 2003, $15.11 in 2002 and $13.11 in 2001. The Corporation estimates that its 2004 unit costs will approximate the 2003 amount.

Other: After-tax foreign currency losses amounted to $22 million ($4 million before income taxes) in 2003 compared with income of $6 million ($26 million before income taxes) in 2002 and a loss of $17 million ($21 million before income taxes) in 2001.

The effective income tax rate for exploration and production operations in 2003 was 51%. This includes income taxes paid in jurisdictions with rates in excess of the United States statutory rate in several producing areas, such as the United Kingdom and Norway. It also reflects an income tax deduction for the Corporation's hedging results at the U.S. statutory rate. In addition, certain expenses in foreign jurisdictions are benefited at rates equal to or below the U.S. statutory rate. Each of these factors increases the Corporation's overall exploration and production effective income tax rate. During 2002, the United Kingdom government enacted a 10% supplementary tax on profits from oil and gas production. The effect of this supplementary tax was an increase in exploration and production income taxes of approximately $60 million in 2003 and $37 million in 2002. The effective income tax rate for exploration and production operations in 2004 is expected to be in the range of 47% to 51%.

Exploration and production earnings from continuing operations include the following items:

	After Income Taxes		
Millions of dollars	**2003**	2002	2001
Accrued severance and London office lease costs	**$(32)**	$ —	$(10)
United States income tax benefit	**30**	—	—
Gains from asset sales	**31**	34	—
Asset impairments	**—**	(737)	—
Charge for increase in United Kingdom income tax rate	**—**	(43)	—
Charge related to Enron bankruptcy	**—**	—	(19)
	$ 29	$(746)	$(29)

	Before Income Taxes		
Millions of dollars	**2003**	2002	2001
Accrued severance and London office lease costs	**$(53)**	$ —	$(15)
Gains from asset sales	**47**	41	—
Asset impairments	**—**	(1,024)	—
Charge related to Enron bankruptcy	**—**	—	(29)
	$ (6)	$ (983)	$(44)

2003: The Corporation recorded an after-tax charge of $32 million for accrued severance in the United States and United Kingdom and a reduction of leased office space in London. The pre-tax amount of this charge was $53 million, of which $32 million relates to leased office space. The remainder of $21 million 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. Approximately 240 employees are receiving severance, $15 million of which has been paid through year-end. The remainder is expected to be paid in 2004. Additional accruals for severance and lease costs of approximately $15 million before income taxes are anticipated in the first half of 2004. The annual savings from this cost reduction initiative is estimated to be approximately $50 million before income taxes. The Corporation anticipates realizing approximately sixty percent of these savings in 2004 and the full amount in 2005.

The Corporation recorded an income tax benefit of $30 million reflecting the recognition for United States income tax purposes of certain prior year foreign exploration expenses. Gains from asset sales in 2003 reflect $31 million ($47 million before income taxes) from the sale of the Corporation's 1.5% interest in the Trans Alaska Pipeline System.

2002: Exploration and production earnings included after-tax asset impairments of $737 million ($1,024 million before income taxes), $530 million of which related to the Ceiba Field in Equatorial Guinea. The pre-tax amount of the Ceiba Field impairment was $706 million. The charge resulted from a 12% reduction in the estimated total field reserves that will ultimately be produced from the field, as well as higher anticipated development costs needed to produce the remaining reserves at lower production rates over a longer time frame.

The amount of Ceiba Field proved reserves was about the same at the end of 2002 as the amount at the beginning of the year (excluding 2002 production) and, therefore, the 12% reduction in total field reserves resulted from a decrease in probable reserves. The net proved reserves did not change in 2002 as a result of the recognition of a more efficient primary recovery factor than previously estimated, and to a lesser extent the positive impact of the initiation of water injection operations in February 2002 to maintain reservoir pressure, and additional drilling.

The reduction in estimated recoverable reserves was attributable to disappointing 2002 year-end drilling results on the western flank of the field. The reduction in probable reserves and higher estimated future development costs resulted in an asset impairment because projected discounted cash flows were less than the book value of the field, which includes allocated purchase price from the Triton acquisition.

The Corporation also recorded an after-tax impairment charge of $207 million ($318 million before income taxes) 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.

During 2002, the United Kingdom government enacted a 10% supplementary tax on profits from oil and gas production. A one-time charge of $43 million was recorded to increase the existing United Kingdom deferred tax liability on the balance sheet.

A net gain of $34 million ($41 million before income taxes) was 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.

2001: The Corporation recorded an after-tax charge of $19 million ($29 million before income taxes) for estimated losses due to the bankruptcy of certain subsidiaries of Enron Corporation. In addition, the Corporation recorded a net charge of $10 million ($15 million before income taxes) for severance expenses resulting from cost reduction initiatives.

The Corporation's future exploration and production earnings may be impacted by volatility in the selling prices of crude oil and natural gas, reserve and production changes, fluctuations in foreign exchange rates and changes in tax rates.

Refining and Marketing: Earnings from refining and marketing activities amounted to $327 million in 2003, $85 million in 2002 and $233 million in 2001. The Corporation's downstream operations include HOVENSA L.L.C. (HOVENSA), a 50% owned refining joint venture with a subsidiary of Petroleos de Venezuela S.A. (PDVSA), accounted for on the equity method. Additional refining and marketing activities include a fluid catalytic cracking facility in Port Reading, New Jersey, as well as retail gasoline stations, energy marketing and trading operations.

HOVENSA: The Corporation's share of HOVENSA's income was $117 million in 2003, compared with a loss of $47 million in 2002 and income of $58 million in 2001. The increase in 2003 was due to higher refining margins and sales volumes compared with 2002. Crude runs were reduced in 2002 as a result of low refining margins and the shutdown of the fluid catalytic cracking unit for approximately two months. Income taxes on the Corporation's share of HOVENSA's results were offset by available loss carryforwards.

HOVENSA's total crude runs amounted to 440,000 barrels per day in 2003, 361,000 barrels per day in 2002 and 403,000 barrels per day in 2001. In late 2002 and very early 2003, crude oil deliveries to HOVENSA were interrupted due to political disturbances in Venezuela. For the remainder of 2003, HOVENSA received contracted quantities of crude oil from PDVSA. The fluid catalytic cracking unit at HOVENSA operated at 142,000, 116,000 and 123,000 barrels per day in 2003, 2002 and 2001, respectively. The coking unit at HOVENSA commenced production in August 2002. The unit operated at the rate of 53,000 barrels per day in 2003.

Earnings from refining and marketing activities also include interest income on the note received from PDVSA at the formation of the joint venture. Interest on the PDVSA note amounted to $30 million in 2003, $35 million in 2002 and $39 million in 2001. Interest income is reflected in non-operating income in the income statement.

Retail, Energy Marketing and Other: Earnings from retail gasoline operations were higher in 2003 compared with 2002, reflecting increased margins and sales volumes. Retail gasoline operations in 2002 were profitable but less so than in 2001, reflecting lower margins. Energy marketing activities had increased earnings in 2003, reflecting increased margins and sales volumes in the early part of the year resulting from the cold winter. Energy marketing activities were profitable in 2002 compared with a loss in 2001. Results of the Port Reading refining facility improved in 2003 reflecting higher margins than in 2002. Total refined product sales volumes were 153 million barrels in 2003, 140 million barrels in 2002 and 141 million barrels in 2001.

The Corporation has a 50% voting interest in a consolidated partnership that trades energy commodities and energy derivatives. The Corporation also takes trading positions in addition to its hedging program. The Corporation's after-tax results from trading activities, including its share of the earnings of the trading partnership amounted to income of $17 million in 2003, $3 million in 2002 and $45 million in 2001. Before income taxes, the trading income was $30 million in 2003, $6 million in 2002 and $72 million in 2001.

Refining and marketing earnings include the following items:

	After Income Taxes		
Millions of dollars	**2003**	2002	2001
Gain (loss) from asset sales	**$(20)**	$ 67	$ —
Reduction in carrying value of intangible assets	**—**	(14)	—
Severance accrual	**—**	(8)	(2)
	$(20)	$ 45	$ (2)

	Before Income Taxes		
Millions of dollars	**2003**	2002	2001
Gain (loss) from asset sales	**$(9)**	$102	$ —
Reduction in carrying value of intangible assets	**—**	(22)	—
Severance accrual	**—**	(13)	(3)
	$(9)	$ 67	$ (3)

In 2003, refining and marketing earnings include a net loss of $20 million (loss of $9 million before income taxes) from the sale of the Corporation's interest in a shipping joint venture.

In 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 net gain of $67 million ($102 million before income taxes). In connection with this sale, the Corporation agreed to support the buyer's charter rate on these vessels for up to five years. The support agreement requires that if the actual contracted rate for the charter of a vessel is less than the stipulated support rate in the agreement the Corporation will pay to the buyer the difference between the contracted rate and the stipulated rate. 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 charters entered into in 2003, and estimates of future charter rates, the Corporation lowered the estimated charter support reserve by $11 million. The balance in this reserve at December 31, 2003 was $32 million.

The Corporation recorded an after-tax charge of $14 million ($22 million before income taxes) in 2002 for the write-off of intangible assets in its U.S. energy marketing business. In addition, after-tax accrued severance of $8 million ($13 million before income taxes) was recorded for cost reduction initiatives in refining and marketing, principally energy marketing.

Refining and marketing earnings will likely continue to be volatile reflecting competitive industry conditions and supply and demand factors, including the effects of weather.

Corporate: After-tax corporate expenses amounted to $101 million in 2003, $63 million in 2002 and $78 million in 2001. The 2003 amount includes expenses of $34 million for premiums paid on the repurchase of bonds compared with $6 million in 2002. The pre-tax amounts of the bond repurchase premiums were $58 million in 2003 and $15 million in 2002 and are recorded in non-operating income (expense) in the income statement. Corporate administrative expenses, before income taxes, increased slightly in 2003 and were comparable in 2002 and 2001. The decrease in after-tax expenses in 2002 reflects lower United States taxes on foreign source income. After-tax corporate expenses for 2004 are estimated to be in the range of $60 to $70 million.

Interest: After-tax interest was $173 million in 2003, $165 million in 2002 and $135 million in 2001. The corresponding amounts before income taxes were $293 million, $256 million and $194 million in 2003, 2002 and 2001, respectively. Interest incurred in 2003 was lower than in 2002 because of debt reduction; however, the reduction in interest incurred was more than offset by lower capitalized interest in 2003. Capitalized interest in 2003, 2002 and 2001 was $41 million, $101 million and $44 million, respectively. Interest expense was higher in 2002 compared with 2001 reflecting increased borrowings related to acquisitions. After-tax interest expense in 2004 is anticipated to be approximately 20% below the 2003 level.

Discontinued Operations: 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 Block A-18 in the joint development area of Malaysia and Thailand (JDA). The exchange resulted in an after-tax charge to income of $47 million ($51 million before income taxes). The after-tax loss on this exchange included a $43 million adjustment of the book value of the Colombian assets to fair value. The loss also included $17 million from the recognition in earnings of the value of related hedge contracts at the time of the exchange. These items were partially offset by after-tax earnings in Colombia prior to the exchange of $13 million. The JDA production facilities are complete, but production will not commence until the purchasers of the gas complete the construction of a natural gas pipeline. The Corporation anticipates that production will begin in the second half of 2005.

In the second quarter of 2003, the Corporation sold Gulf of Mexico shelf properties, the Jabung Field in Indonesia and several small United Kingdom fields for $445 million. The after-tax gain from these asset sales of $175 million ($248 million before income taxes) was included in discontinued operations. Discontinued operations in 2003 also includes $40 million of income from operations prior to the sales of these assets.

Change in Accounting Principle: The Corporation adopted FAS No. 143, *Accounting for Asset Retirement Obligations,* effective January 1, 2003. A net after-tax gain of $7 million resulting from the cumulative effect of this accounting change was recorded at the beginning of the year. At the date of adoption, a liability of $556 million representing the estimated fair value of the Corporation's required dismantlement obligations was recorded on the balance sheet. In addition, a dismantlement asset of $311 million was recorded, as well as accumulated depreciation of $203 million.

Sales and Other Operating Revenues: In 2003, sales and other operating revenues increased by 24% compared with 2002. This increase principally reflects increased sales volumes and selling prices of refined products and the higher selling price of purchased natural gas in energy marketing activities. Sales and other operating revenues decreased by 12% in 2002 compared with 2001, due to the sale of the United Kingdom energy marketing business, and lower sales volumes of refined products and purchased natural gas related to U.S. energy marketing. These decreases were partially offset by higher production of crude oil and natural gas. The change in cost of goods sold in each year reflects the change in sales of refined products and purchased natural gas.

Liquidity and Capital Resources

Overview: Cash flows from operating activities, including changes in operating assets and liabilities, totaled $1,581 million in 2003. During the year, the Corporation strengthened its financial position through sales of assets and the issuance of preferred stock. At December 31, 2003, the Corporation's debt to capitalization ratio was 42.5% compared to 54.0% at December 31, 2002. Total debt was $3,941 million at December 31, 2003 and $4,992 million at December 31, 2002. Cash and cash equivalents at the end of 2003 totaled $518 million, an increase of $321 million for the year. Long-term debt totaling $221 million matures over the next three years.

The Corporation has hedged the selling prices of a significant portion of its crude oil and natural gas production in 2004 and 2005 to help generate a level of cash flow that will meet operating and capital commitments.

Cash Flows from Operating Activities: Net cash provided by operating activities, including changes in operating assets and liabilities, totaled $1,581 million in 2003, $1,965 million in 2002 and $1,960 million in 2001. Lower cash flows in 2003 were primarily due to reduced exploration and production sales volumes.

Cash Flows from Investing Activities: The following table summarizes the Corporation's capital expenditures in 2003, 2002 and 2001:

Millions of dollars	**2003**	2002	2001
Exploration and production			
Exploration	**$ 196**	$ 239	$ 171
Production and development	**1,067**	1,095	1,250
Acquisitions	**23**	70	3,640
	1,286	1,404	5,061
Refining and marketing			
Operations	**72**	83	110
Acquisitions	**—**	47	50
	72	130	160
Total	**$1,358**	$1,534	$5,221

Capital expenditures in 2001 included $2,720 million for the Triton acquisition, excluding the assumption of debt. In addition, the Corporation purchased crude oil and natural gas reserves in the Gulf of Mexico and onshore Louisiana for $920 million. The amounts shown for acquisitions in 2002 principally represent final installment payments on prior year acquisitions.

In 2003, the Corporation took initiatives to reshape its portfolio of producing assets to reduce future costs, increase its reserve to production ratio, and provide capital for investment in new fields and funds to reduce debt. The Corporation sold certain producing properties in the Gulf of Mexico Shelf, the Jabung Field in Indonesia, several small United Kingdom fields and an interest in a shipping joint venture. Proceeds from asset sales totaled $545 million during 2003. In addition, the Corporation completed several asset exchanges. The Corporation swapped mature, high-cost assets in Colombia for an additional 25% interest in long-lived natural gas reserves in Block A-18 in the joint development area of Malaysia and Thailand, bringing the Corporation's interest in the area to 50%. The Corporation exchanged its 25% equity investment in Premier Oil plc for a 23% interest in Natuna Sea Block A in Indonesia, plus approximately $10 million in cash. In the fourth quarter of 2003, the Corporation exchanged 14% interests in the Scott and Telford fields in the United Kingdom for an additional 22.5% interest in the Llano Field in the Gulf of Mexico and $17 million in cash. This exchange increased the Corporation's working interest in the Llano Field to 50% and decreased its interest in the Scott Field to 21% and the Telford Field to 17%. Production from the Corporation's 50% interest in the Llano Field is scheduled to commence in mid-2004.

The net production from fields sold or exchanged at the time of disposition was approximately 50,000 barrels of oil equivalent per day. The Corporation believes the overall impact of its program of asset exchanges and sales of properties has not reduced its liquidity in the short-term or over the next five years.

In 2002, the Corporation sold United States Flag vessels, its energy marketing business in the United Kingdom and several small oil and gas fields for net proceeds of $412 million.

Cash Flows from Financing Activities: In the fourth quarter of 2003, the Corporation issued 13,500,000 shares of mandatory convertible preferred stock for net proceeds of $653 million. Cash flows from operations, asset sales and the issuance of preferred stock enabled the Corporation to reduce debt by $1,051 million during 2003. Debt repayment in 2002, net of new borrowings, was $673 million.

Future Capital Requirements and Resources: Capital expenditures in 2004 are expected to be approximately $1.5 billion. The Corporation anticipates that these expenditures will be funded by available cash and cash flow from operations. Lines of credit are available, if necessary. At December 31, 2003, the Corporation has an undrawn facility of $1.5 billion under its committed revolving credit agreement and has additional unused lines of credit of $206 million under uncommitted arrangements with banks. The Corporation's revolving credit agreement expires in 2006 and the Corporation expects it will be able to arrange a new committed facility at that time, if required. The Corporation also has a shelf registration under which it may issue $825 million of additional debt securities, warrants, common stock or preferred stock.

Loan agreement covenants allow the Corporation to borrow an additional $5 billion for the construction or acquisition of assets at December 31, 2003. At year end, the amount that can be borrowed under the loan agreements for the payment of dividends is $1.9 billion.

The Corporation's aggregate maturities of long-term debt total $221 million over the next three years. Based on current estimates of production, capital expenditures and other factors, and assuming West Texas Intermediate oil prices average $24 per barrel and United States natural gas prices average $4.25 per Mcf, the Corporation anticipates it will fund its future operations, including capital expenditures, dividends and required debt repayment, with existing cash on-hand, cash flow from operations and, when necessary, borrowings under its credit facilities and the issuance of securities under its shelf registration.

Prior to June 30, 1986, the Corporation had extensive exploration and production operations in Libya, however, it was required to suspend participation in these operations as a result of U.S. government sanctions. If U.S. sanctions on Libya are removed, and if the Corporation and its partners successfully negotiate with the government of Libya to resume participation in the group's former operations, management anticipates capital expenditures will likely increase over the current plan. Production and reserves would also increase. On February 24, 2004, the Corporation received U.S. Government authorization to negotiate and enter into an executory agreement with the government of Libya that would define the terms for resuming active participation in the Libyan properties. The Corporation's performance under this agreement will be contingent on obtaining future U.S. Government authorizations. The Corporation cannot predict the outcome or timing of these events.

Credit Ratings: While the Corporation maintains investment grade ratings from two rating agencies, one credit rating agency downgraded its rating of the Corporation's debt to non-investment grade in February 2004. Cash margin or collateral is required under certain contracts with hedging and trading counterparties and certain lenders. The amount of such cash margin or collateral would have increased at December 31, 2003 by approximately $230 million as a result of the downgrade. The downgrade is expected to increase annual pre-tax financing costs by less than $10 million.

Contractual Obligations and Contingencies: Following is a table showing aggregated information about certain contractual obligations at December 31, 2003:

		Payments Due by Period			
Millions of dollars	*Total*	*2004*	*2005 and 2006*	*2007 and 2008*	*Thereafter*
Long-term debt	$ 3,893	$ 63	$ 126	$ 327	$3,377
Capital leases	48	10	22	14	2
Operating leases	1,303	95	142	142	924
Purchase obligations					
Supply commitments	14,706	5,233	4,847	4,626	*
Capital expenditures	799	433	296	70	—
Operating expenses	266	170	44	31	21
Other long-term liabilities	235	110	56	32	37

**The Corporation intends to continue purchasing its refined product supply from HOVENSA. Current purchases amount to approximately $2 billion annually.*

In the preceding table, the Corporation's supply commitments include its estimated purchases of 50% of HOVENSA's production of refined products, after anticipated sales by HOVENSA to unaffiliated parties. Also included are normal term purchase agreements at market prices for additional gasoline necessary to supply the Corporation's retail marketing system and feedstocks for the Port Reading refining facility. In addition, the Corporation has commitments to purchase natural gas for use in supplying contracted customers in its energy marketing business. These commitments were computed based on year-end market prices.

The table also reflects that portion of the Corporation's planned capital expenditures that are contractually committed at December 31. The Corporation's 2004 capital expenditures are estimated to be approximately $1.5 billion, including approximately $900 million for oil and gas developments. Obligations for operating expenses include commitments for transportation, seismic purchases, oil and gas production expenses and other normal business expenses. Other long-term liabilities reflect contractually committed obligations on the balance sheet at December 31, including minimum pension plan funding requirements.

In connection with the sale of six vessels in 2002, the Corporation agreed to support the buyer's charter rate on these vessels for up to five years. The support agreement requires that if the actual contracted rate for the charter of a vessel is less than the stipulated support rate in the agreement, the Corporation will pay to the buyer the difference between the contracted rate and the stipulated rate. The balance in the charter support reserve at December 31, 2003 was $32 million.

The Corporation has a contingent purchase obligation to acquire the remaining 50% interest in a retail marketing and gasoline station joint venture for $88 million.

The Corporation guarantees the payment of up to 50% of HOVENSA's crude oil purchases from suppliers other than PDVSA. The amount of the Corporation's guarantee fluctuates based on the volume of crude oil purchased and related prices and at December 31, 2003 amounted to $134 million.

In addition, the Corporation has agreed to provide funding up to a maximum of $40 million to the extent HOVENSA does not have funds to meet its senior debt obligations.

At December 31, the Corporation is contingently liable under letters of credit and under guarantees of the debt of other entities directly related to its business, as follows:

Millions of dollars	*Total*
Letters of credit	$ 7
Guarantees	92*
	$99

**Includes $40 million HOVENSA debt guarantee discussed above. The remainder relates principally to a loan guarantee for a natural gas pipeline in which the Corporation owns a 5% interest.*

Off-Balance Sheet Arrangements: The Corporation has leveraged lease financings not included in its balance sheet, primarily related to retail gasoline stations that the Corporation operates. The net present value of these financings is $462 million at December 31, 2003, using interest rates inherent in the leases. The Corporation's December 31, 2003 debt to capitalization ratio would increase from 42.5% to 45.2% if the lease financings were included.

See also *"Contractual Obligations and Contingencies"* above, Note No. 7, "Refining Joint Venture," and Note No. 18, "Guarantees and Contingencies," in the financial statements.

Foreign Operations: The Corporation conducts exploration and production activities in many foreign countries, including the United Kingdom, Norway, Denmark, Gabon, Indonesia, Thailand, Azerbaijan, Algeria, Malaysia and Equatorial Guinea. Therefore, the Corporation is subject to the risks associated with foreign operations. These exposures include political risk (including tax law changes) and currency risk. The effects of these events are accounted for when they occur and generally have not been material to the Corporation's liquidity or financial position.

HOVENSA L.L.C., owned 50% by the Corporation and 50% by Petroleos de Venezuela, S.A. (PDVSA), owns and operates a refinery in the Virgin Islands. Although there have in the past been political disruptions in Venezuela that reduced the availability of Venezuelan crude oil used in refining operations, these disruptions did not have a material adverse effect on the Corporation's financial position. The Corporation also has a note receivable of $334 million at December 31, 2003 from a subsidiary of PDVSA. The Corporation anticipates collection of the remaining balance.

Market Risk Disclosure

In the normal course of its business, the Corporation is exposed to commodity risks related to changes in the price of crude oil, natural gas, refined products and electricity, as well as to changes in interest rates and foreign currency values. In the disclosures which follow, these operations are referred to as non-trading activities. The Corporation also has trading operations, principally through a 50% voting interest in a trading partnership. These activities are also exposed to commodity risks primarily related to the prices of crude oil, natural gas and refined products. The following describes how these risks are controlled and managed.

Controls: The Corporation maintains a control environment under the direction of its chief risk officer and through its corporate risk policy, which the Corporation's senior management has approved. Controls include volumetric, term and value-at-risk limits. In addition, the chief risk officer must approve the use of new instruments or commodities. Risk limits are monitored daily and exceptions are reported to business units and to senior management. The Corporation's risk management department also performs independent verifications of sources of fair values and validations of valuation models. These controls apply to all of the Corporation's non-trading and trading activities, including the consolidated trading partnership. The Corporation's treasury department administers foreign exchange rate and interest rate hedging programs.

Instruments: The Corporation uses forward commodity contracts, foreign exchange forward contracts, futures, swaps and options in the Corporation's non-trading and trading activities. These contracts are widely traded instruments mainly with standardized terms. The following describes these instruments and how the Corporation uses them:

- ***Forward Commodity Contracts:*** The forward purchase and sale of commodities is performed as part of the Corporation's normal activities. At title date, the notional value of the contract is exchanged for physical delivery of the commodity. Forward contracts that are designated as normal purchase and sale contracts under FAS No. 133 are excluded from the quantitative market risk disclosures.

- ***Forward Foreign Exchange Contracts:*** Forward contracts include forward purchase contracts for both the British pound sterling and the Danish kroner. These foreign currency contracts commit the Corporation to purchase a fixed amount of pound sterling and kroner at a predetermined exchange rate on a certain date.

- ***Futures:*** The Corporation uses exchange traded futures contracts on a number of different underlying energy commodities. These contracts are settled daily with the relevant exchange and are subject to exchange position limits.

- ***Swaps:*** The Corporation uses financially settled swap contracts with third parties as part of its hedging and trading activities. Cash flows from swap contracts are determined based on underlying commodity prices and are typically settled over the life of the contract.

- ***Options:*** Options on various underlying energy commodities include exchange traded and third party contracts and have various exercise periods. As a seller of options, the Corporation receives a premium at the outset and bears the risk of unfavorable changes in the price of the commodity underlying the option. As a purchaser of options, the Corporation pays a premium at the outset and has the right to participate in the favorable price movements in the underlying commodities.

Quantitative Measures: The Corporation uses value-at-risk to monitor and control commodity risk within its trading and non-trading activities. The value-at-risk model uses historical simulation and the results represent the potential loss in fair value over one day at a 95% confidence level. The model captures both first and second order sensitivities for options. The potential change in fair value based on commodity price risk is presented in the non-trading and trading sections below.

For foreign exchange rate risk, the impact of a 10% change in foreign exchange rates on the value of the Corporation's portfolio of foreign currency forward contracts is presented in the non-trading section. Similarly, the impact of a 15% change in interest rates on the fair value of the Corporation's debt is also presented in the non-trading section. A 10% change in foreign exchange rates and a 15% change in the rate of interest over one year are considered reasonable possibilities for the purpose of providing sensitivity disclosures.

Non-Trading: The Corporation's non-trading activities include hedging of crude oil and natural gas production. Futures and swaps are used to fix the selling prices of a portion of the Corporation's future production and the related gains or losses are an integral part of the Corporation's selling prices. As of December 31, the Corporation has open hedge positions equal to 70% of its estimated 2004 worldwide crude oil production and 45% of its estimated 2005 worldwide crude oil production. The average price for West Texas Intermediate crude oil (WTI) related open hedge positions is $26.24 in 2004 and $25.83 in 2005. The average price for Brent crude oil related open hedge positions is $24.51 in 2004 and $24.41 in 2005. Approximately 18% of the Corporation's hedges are WTI related and the remainder are Brent. The Corporation also has hedged 30% of its 2004 United States natural gas production at an average price of $5.10 per Mcf. As market conditions change, the Corporation may adjust its hedge percentages.

The Corporation also markets energy commodities including refined petroleum products, natural gas and electricity. The Corporation uses futures and swaps to fix the purchase prices of commodities to be sold under fixed-price sales contracts.

The following table summarizes the value-at-risk results of commodity related derivatives that are settled in cash and used in non-trading activities. The results may vary from time to time as hedge levels change.

Millions of dollars	*Non-Trading Activities*
2003	
At December 31	**$44**
Average for the year	**43**
High during the year	**47**
Low during the year	**40**
2002	
At December 31	$50
Average for the year	49
High during the year	62
Low during the year	34

The Corporation uses foreign exchange contracts to reduce its exposure to fluctuating foreign exchange rates. To counteract these foreign exchange exposures, the Corporation enters into forward purchase contracts for both the British pound sterling and the Danish kroner. At December 31, 2003, the Corporation has $384 million of notional value foreign exchange contracts maturing in 2004 and 2005 ($307 million at December 31, 2002). The fair value of foreign exchange contracts recorded as assets was $40 million at December 31, 2003 ($18 million at December 31, 2002). The change in fair value of the foreign exchange contracts from a 10% change in exchange rates is estimated to be $43 million at December 31, 2003 ($33 million at December 31, 2002).

At December 31, 2003, the interest rate on substantially all of the Corporation's debt is fixed and there are no interest rate swaps. The Corporation's outstanding debt of $3,941 million has a fair value of $4,440 million at December 31, 2003 (debt of $4,992 million at December 31, 2002 had a fair value of $5,569 million). A 15% change in the rate of interest would change the fair value of debt at December 31, 2003 and 2002 by approximately $270 million.

Trading: The trading partnership in which the Corporation has a 50% voting interest trades energy commodities and derivatives. The accounts of the partnership are consolidated with those of the Corporation. The Corporation also takes trading positions for its own account. These strategies include proprietary position management and trading to enhance the potential return on assets. The information that follows represents 100% of the trading partnership and the Corporation's proprietary trading accounts.

In trading activities, the Corporation is exposed to changes in crude oil, natural gas and refined product prices, primarily in North America and Europe. Trading positions include futures, swaps and options. In some cases, physical purchase and sale contracts are used as trading instruments and are included in the trading results.

Gains or losses from sales of physical products are recorded at the time of sale. Derivative trading transactions are marked-to-market and are reflected in income currently. Total realized gains for the year amounted to $50 million. The following table provides an assessment of the factors affecting the changes in fair value of trading activities and represents 100% of the trading partnership and other trading activities.

Millions of dollars	**2003**	2002
Fair value of contracts outstanding at the beginning of the year	**$ 36**	$(58)
Change in fair value of contracts outstanding at the beginning of the year and still outstanding at the end of year	**36**	(14)
Reversal of fair value for contracts closed during the year	**(26)**	75
Fair value of contracts entered into during the year and still outstanding	**21**	33
Fair value of contracts outstanding at the end of the year	**$ 67**	$ 36

The Corporation uses observable market values for determining the fair value of its trading instruments. The majority of valuations are based on actively quoted market values. In cases where actively quoted prices are not available, other external sources are used which incorporate information about commodity prices in actively quoted markets, quoted prices in less active markets and other market fundamental analysis. Internal estimates are based on internal models incorporating underlying market information such as commodity volatilities and correlations. The Corporation's risk management department regularly compares valuations to independent sources and models.

Millions of dollars	Total	2004	2005	2006
Source of fair value				
Prices actively quoted	$69	$33	$36	$—
Other external sources	5	(8)	7	6
Internal estimates	(7)	(4)	(3)	—
Total	$67	$21	$40	$ 6

The following table summarizes the value-at-risk results for all trading activities. The results may change from time to time as strategies change to capture potential market rate movements.

Millions of dollars	*Trading Activities*
2003	
At December 31	**$ 7**
Average for the year	**9**
High during the year	**12**
Low during the year	**7**
2002	
At December 31	$ 6
Average for the year	10
High during the year	12
Low during the year	6

The following table summarizes the fair values of net receivables relating to the Corporation's trading activities and the credit rating of counterparties at December 31:

Millions of dollars	**2003**	2002
Investment grade determined by outside sources	**$246**	$309
Investment grade determined internally*	**89**	70
Less than investment grade	**16**	61
Not determined	**—**	2
	$351	$442

**Based on information provided by counterparties and other available sources.*

Critical Accounting Policies and Estimates

Accounting policies and estimates affect the recognition of assets and liabilities on the Corporation's balance sheet and revenues and expenses on the income statement. The accounting methods used can affect net income, stockholders' equity and various financial statement ratios. However, the Corporation's accounting policies generally do not change cash flows or liquidity.

Accounting for Exploration and Development Costs: The Corporation uses the successful efforts method of accounting for oil and gas producing activities. Costs to acquire or lease unproved and proved oil and gas properties are capitalized. Costs incurred in connection with the drilling and equipping of successful exploratory wells are also capitalized. If proved reserves are not found, these costs are charged to expense. Other exploration costs, including seismic, are charged to expense as incurred. Development costs, which include the costs of drilling and equipping development wells, are capitalized. Depreciation, depletion and amortization of capitalized costs of proved oil and gas properties are computed on the unit-of-production method based on estimates of proved reserves on a field basis.

The determination of estimated proved reserves is a significant element in arriving at the results of operations of exploration and production activities. The Corporation uses independent reservoir engineers to estimate all of its oil and gas reserves. The estimates of proved reserves impact well capitalizations, undeveloped lease impairments and the depreciation rates of proved properties, wells and equipment. Reduction in reserve estimates may result in the need for impairments of proved properties and related assets.

Hedging: Hedging contracts correlate to the selling prices of crude oil or natural gas and the Corporation has designated these contracts as hedges. Therefore, the Corporation records gains or losses on these instruments in income in the period in which the production is sold. At December 31, 2003, the Corporation has $229 million of deferred hedging losses, after income taxes, included in other comprehensive income.

Impairment of Long-Lived Assets and Goodwill: As explained below there are significant differences in the way long-lived assets and goodwill are evaluated and measured for impairment testing. The Corporation reviews long-lived assets, including oil and gas fields, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. Long-lived assets are tested at the lowest level for which cash flows are identifiable and are largely independent of the cash flows of other assets and liabilities. If the carrying amounts of the long-lived assets are not expected to be recovered by undiscounted future net cash flow estimates, 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 present value of future net 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 in the standardized measure of discounted future net cash flows, since the standardized measure requires the use of actual prices on the last day of the year.

The Corporation's impairment tests of long-lived exploration and production producing assets are based on its best estimates of future production volumes (including recovery factors), selling prices, operating and capital costs and the timing of future production, which are updated each time an impairment test is performed. In 2002, the Corporation recorded impairments of the Ceiba Field and LLOG properties that were required primarily because of reduced estimates of oil and gas production volumes and, in the case of Ceiba, anticipated additional development costs. The impairment charges did not result from changes in the other factors. The change in the estimated timing of production on the Ceiba Field did not significantly affect the undiscounted future cash flows, but did significantly reduce the fair value of the field determined by discounted cash flows. The Corporation could have additional impairments if the projected production volumes from oil and gas fields were reduced. Significant extended declines in crude oil and natural gas selling prices could also result in asset impairments.

The Corporation has recorded $977 million of goodwill in connection with the purchase of Triton. 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. In accordance with FAS No. 142, goodwill is no longer amortized but must be tested for impairment annually. FAS No. 142 requires that goodwill be tested for impairment at a reporting unit level. The reporting unit or units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed. A reporting unit is an operating segment or a component which is one level below an operating segment. A component is a reporting unit if the component constitutes a business for which discrete financial information is available and segment management regularly reviews the operating results of that component. However, two or more components of an operating segment shall be aggregated and deemed a single reporting unit if the components have similar economic characteristics. An operating segment shall be deemed to be a reporting unit if all of its components are economically similar.

Within the Corporation's exploration and production operating segment there are currently two components: (1) Americas and West Africa and (2) Europe, North Africa and Asia. Each component has a manager who reports to the segment manager. The Corporation has determined the components have similar economic characteristics and, therefore, has aggregated the components into a single reporting unit — the exploration and production operating segment. As a result, goodwill has been assigned to the exploration and production operating segment. If the Corporation reorganized its exploration and production business such that there was more than one operating segment, or its components were no longer economically similar, goodwill would be assigned to two or more reporting units. The goodwill would be allocated to any new reporting units using a relative fair value approach in accordance with FAS No. 142. Goodwill impairment testing for lower level reporting units could result in the recognition of an impairment that would not otherwise be recognized at the current higher level of aggregation.

The Corporation expects that the benefits of goodwill will be recovered through the operation of the exploration and production segment as a whole and it evaluated the following characteristics in determining that the components are economically similar:

- The Corporation operates its exploration and production segment as a single, global business.
- Each component produces oil and gas.
- The exploration and production processes are similar in each component.
- The methods used by each component to market and distribute oil and gas are similar.
- Customers of each component are similar.
- The components share resources and are supported by a worldwide exploration team and a shared services organization.

The Corporation's fair value estimate of the exploration and production segment is the sum of: (1) the discounted anticipated cash flows of producing assets and known developments, (2) the expected risked present value of exploration assets, and (3) an estimated market premium to reflect the market price an acquirer would pay for potential synergies including cost savings, access to new business opportunities, enterprise control, improved processes and increased market share. The Corporation also considers the relative market valuation of similar exploration and production companies.

The determination of the fair value of the exploration and production operating segment depends on estimates about oil and gas reserves, future prices, timing of future net cash flows and market premiums. The effect of synergies is embedded in the value of producing assets, known developments and exploration assets. Significant extended declines in crude oil and natural gas prices, reduced reserve estimates or failure to realize synergies could lead to a decrease in the fair value of the exploration and production operating segment that could result in an impairment of goodwill. In addition, changes in management structure or sales or dispositions of a portion of the exploration and production segment may result in goodwill impairment.

Because there are significant differences in the way long-lived assets and goodwill are evaluated and measured for impairment testing, there may be impairments of individual assets which would not cause an impairment of the $977 million of goodwill assigned to the exploration and production segment. In 2002, the Corporation recognized asset impairments because reduced estimates of oil and gas production volumes caused the expected undiscounted cash flows of the assets to be lower than the asset carrying amounts. No impairment of goodwill existed because the fair value of the overall exploration and production operating segment continued to exceed its recorded book value.

Segments: The Corporation has two operating segments, exploration and production, and refining and marketing. Management has determined that these are its operating segments because, in accordance with FAS No. 131, these are the segments of the Corporation (i) that engage in business activities from which revenues are earned and expenses are incurred, (ii) whose operating results are regularly reviewed by the Corporation's chief operating decision maker to make decisions about resources to be allocated to the segment and assess its performance and (iii) for which discrete financial information is available. Mr. John B. Hess, Chairman of the Board and Chief Executive Officer of the Corporation, is the chief operating decision maker ("CODM") as defined in FAS No. 131, because he is responsible for performing the functions within the Corporation of allocating resources to, and assessing the performance of, the Corporation's operating segments. Mr. Hess uses only the operating results of each segment as a whole to make decisions about resources to be allocated to each segment and to assess the segment performance. The CODM manages each segment globally and does not regularly review the operating results of any component (e.g., geographic area) or asset within each segment or any such information by geographical location, oil and gas property or project, subsidiary or division, to make decisions about resources to be allocated or to assess performance. While the CODM does review and approve initial corporate funding for a new project using information about the project, he does not review subsequent operating results by project after the initial funding. Each operating segment has one manager. The segment managers are responsible for allocating resources within the segments, reviewing financial results of components within the segments, and assessing the performance of the components. The CODM evaluates the performance of the segment managers based on performance metrics related to each manager's operating segment as a whole. The Board of Directors of the Corporation does not receive more detailed information than that used by the CODM to operate and manage the Corporation.

Oil and Gas Mineral Rights: 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 notes. This potential balance sheet reclassification would not affect results of operations or cash flows.

Environment, Health and Safety

The Corporation has implemented a values-based, social-responsibility strategy focused on improved environment, health, and safety performance and making a positive impact on communities and the environment. The strategy is supported by the Corporation's environment, health, safety and social responsibility policies and management systems that help protect the Corporation's workforce, customers and local communities. Overall governance is the responsibility of senior management. To ensure that the Corporation meets its goals and regulatory requirements, the Corporation has programs in place for compliance evaluation, facility auditing and employee training. Environment and safety management systems, based on international standards, are used throughout the Corporation to ensure consistency and adherence to policy objectives. Improved performance in environment, health and safety may raise the Corporation's operating costs and require increased capital expenditures while reducing potential risks to corporate assets, reputation and ability to operate.

The Port Reading refining facility and the HOVENSA refinery manufacture conventional and reformulated gasolines that are cleaner burning than required under U.S. regulations currently in effect. In addition, the benzene and sulfur content in the Corporation's gasoline is approximately one-half of the national average (excluding California), resulting in significantly lower toxic emissions than the industry average.

The regulation of motor fuels in the United States and elsewhere continues to be an area of considerable change and will likely require large capital expenditures in future years. In December 1999, the United States Environmental Protection Agency ("EPA") adopted rules that phase in limitations on the sulfur content of gasoline beginning in 2004. In December 2000, the EPA adopted regulations to substantially reduce the allowable sulfur content of diesel fuel by 2006.

The Corporation and HOVENSA continue to review options to determine the most cost effective compliance strategies for these fuel regulations. The costs to comply will depend on a variety of factors, including the availability of suitable technology and contractors and the credit trading programs. The estimated capital expenditures necessary to comply with the low-sulfur gasoline requirements at Port Reading are approximately $70 million over the next several years. Capital expenditures to comply with low-sulfur gasoline and diesel fuel requirements at HOVENSA are presently expected to be $450 million over the next three years. HOVENSA expects to finance these capital expenditures through cash flow and, if necessary, future borrowings.

Legislation to restrict or ban the use of MTBE, a gasoline oxygenate, and to require the use of 'renewable' fuels was considered by the United States Congress in 2002 and will likely be reconsidered. The Corporation and HOVENSA both manufacture and use MTBE primarily to meet the federal requirement for oxygen in reformulated gasoline, and do not presently use ethanol. Several states in the Corporation's market area have enacted bans on MTBE use, including Connecticut and New York (effective January 2004), and other states are considering them. If Congress bans MTBE or if additional state bans take effect, or if an obligation to use ethanol or other renewable fuels is imposed, the effect on the Corporation and HOVENSA could be significant. Whether the effect is significant will depend on several factors, including the extent and timing of any such bans or obligations, requirements for maintenance of certain air emission reductions if MTBE is banned, the cost and availability of alternative oxygenates or credits and whether the minimum oxygen content standard for reformulated gasoline remains in effect. The Corporation is reviewing various options to market and produce reformulated gasolines if additional MTBE bans take effect.

In 2003, the Corporation and HOVENSA began discussions with the U.S. EPA regarding the EPA's Petroleum Refining Initiative (PRI). The PRI is an ongoing program that is designed to reduce certain air emissions at all U.S. refineries. Presently over 40% of U.S. refining capacity is operating under PRI controls and an additional 37% of refining capacity will be included in early 2004. Depending on the outcome of these discussions, which will not likely be concluded until 2005, the Corporation and HOVENSA may experience increased capital and operating expenses related to air emissions controls. The PRI allows for controls to be phased in over several years.

The Corporation recognizes the worldwide concern about the environmental impact of air emissions. On a global scale, climate change is an issue that has prompted much public debate and has a potential impact on future growth and development. The Corporation has undertaken a program to assess, monitor and reduce the emission of "greenhouse gases," including carbon dioxide and methane. The challenges associated with this program may be significant, not only from the standpoint of technical feasibility, but also from the perspective of adequately measuring the Corporation's entire greenhouse gas inventory. The Corporation is working to establish an internal greenhouse gas reporting protocol that will provide a common set of principles and guidelines for reporting data from operated facilities and from assets operated by the Corporation's partners.

The Corporation expects continuing expenditures for environmental assessment and remediation related primarily to existing conditions. Sites where corrective action may be necessary include gasoline stations, terminals, onshore exploration and production facilities, refineries (including solid waste management units under permits issued pursuant to the Resource Conservation and Recovery Act) and, although not significant, "Superfund" sites where the Corporation has been named a potentially responsible party.

The Corporation accrues for environmental expenses when the future costs are probable and reasonably estimable. At year end 2003, the Corporation's reserve for its estimated environmental liability was approximately $85 million. Remediation spending was $12 million in 2003, $9 million in 2002, and $8 million in 2001. Capital expenditures for facilities, primarily to comply with federal, state and local environmental standards, were $7 million in 2003, $5 million in 2002, and $6 million in 2001. The Corporation expects that existing reserves for environmental liabilities will adequately cover costs to assess and remediate known sites.

Dividends

Cash dividends on common stock totaled $1.20 per share ($.30 per quarter) during 2003 and 2002. Dividends on the 7% cumulative mandatory convertible preferred stock will total $3.50 per share ($.875 per quarter).

Stock Market Information

The common stock of Amerada Hess Corporation is traded principally on the New York Stock Exchange (ticker symbol: AHC). High and low sales prices in 2003 and 2002 were as follows:

	2003		2002	
Quarter Ended	***High***	***Low***	*High*	*Low*
March 31	**$57.20**	**$41.14**	$80.15	$57.60
June 30	**51.50**	**43.51**	84.70	74.61
September 30	**50.90**	**45.04**	83.00	61.36
December 31	**55.25**	**46.09**	71.48	49.40

The high and low sales prices of the Corporation's 7% cumulative mandatory convertible preferred stock (traded on the New York Stock Exchange, ticker symbol: AHCPR) since issuance in the fourth quarter of 2003 to December 31 were $55.43 and $49.50, respectively.

Quarterly Financial Data

Quarterly results of operations for the years ended December 31, 2003 and 2002 follow:

Millions of dollars, except per share data	*Sales and other operating revenues*	*Gross profit (a)*	*Net income (loss)(b)*	*Net income (loss) per share*
2003				
First	**$4,254**	**$477**	**$ 177[c]**	**$ 1.98**
Second	**3,199**	**382**	**252[d]**	**2.83**
Third	**3,230**	**361**	**146[e]**	**1.64**
Fourth	**3,628**	**394**	**68[d][f]**	**.71**
2002				
First	$2,926	$368	$ 140[g]	$ 1.58
Second	2,694	385	149[h]	1.66
Third	2,724	419	(136)[i]	(1.54)
Fourth	3,207	431	(371)[j]	(4.20)

(a) Gross profit represents sales and other operating revenues, less cost of products sold, production expenses, marketing expenses, other operating expenses and depreciation, depletion and amortization.

(b) Includes net income (loss) from discontinued operations, as follows:

Quarter	*2003*	*2002*
First	*$ (20)*	*$ 9*
Second	*189*	*20*
Third	*—*	*(31)*
Fourth	*—*	*29*

(c) Includes income of $7 million from the cumulative effect of the adoption of FAS No. 143, Accounting for Asset Retirement Obligations. *Also includes income of $31 million ($47 million before income taxes) from asset sales.*

(d) Includes after-tax charges of $23 million ($38 million before income taxes) in the second quarter and $9 million ($15 million before income taxes) in the fourth quarter for accrued severance and a reduction in leased office space in London. Also includes a net loss in the second quarter of $20 million ($9 million before income taxes) from the sale of a shipping joint venture.

(e) Includes a U.S. income tax benefit of $30 million for the recognition of certain prior year foreign exploration expenses.

(f) Includes $19 million after-tax ($31 million before income taxes) for premiums paid on repurchase of bonds.

(g) Reflects a net gain from asset sales of $42 million ($62 million before income taxes).

(h) Includes charges of $14 million ($22 million before income taxes) for the reduction in carrying value of intangible assets related to energy marketing activities and $8 million ($13 million before income taxes) for a severance accrual.

(i) Reflects a net charge of $207 million ($318 million before income taxes) for impairment of U.S. producing properties and exploration acreage. Also includes a net gain from asset sales of $45 million ($68 million before income taxes) and a deferred tax charge of $43 million for an increase in the United Kingdom income tax rate.

(j) Includes a net charge of $530 million ($706 million before income taxes) for impairment of the Ceiba Field. Also includes a net gain from an asset sale of $13 million.

The results of operations for the periods reported herein should not be considered as indicative of future operating results.

Forward Looking Information

Certain sections of Management's Discussion and Analysis of Results of Operations and Financial Condition, including references to the Corporation's future results of operations and financial position, liquidity and capital resources, capital expenditures, oil and gas production, tax rates, debt repayment, hedging, derivative, market risk and environmental disclosures, off-balance sheet arrangements and contractual obligations and contingencies include forward looking information. Forward looking disclosures are based on the Corporation's current understanding and assessment of these activities and reasonable assumptions about the future. Actual results may differ from these disclosures because of changes in market conditions, government actions and other factors.