Financial Table of Contents

Management's Discussion and Analysis (MD&A)

INTRODUCTION

We use the MD&A to explain Texaco's operating results and general financial condition. A table of financial highlights that provides a financial picture of the company is followed by four main sections: Industry Review, Results of Operations, Analysis of Income by Operating Segments and Other Items.

Industry Review — we discuss the economic factors that affected our industry in 1999. We also provide our near-term outlook for the industry.

Results of Operations — we explain changes in consolidated revenues, costs, expenses and income taxes. Summary schedules, showing results before and after special items, complete this section. Special items are significant benefits or charges outside the scope of normal operations.

Analysis of Income by Operating Segments — we discuss the performance of our operating segments: Exploration and Production (Upstream), Refining, Marketing and Distribution (Downstream) and Global Gas and Power. We also discuss Other Business Units and our Corporate/Non-operating results.

Other Items section includes:

> Liquidity and Capital Resources: How we manage cash, working capital and debt and other actions to provide financial flexibility

> Reorganizations, Restructurings and Employee Separation Programs: A discussion of our reorganizations and other cost-cutting initiatives

> Capital and Exploratory Expenditures: Our program to invest in the business, especially in projects aimed at future growth

> Environmental Matters: A discussion about our expenditures relating to protection of the environment

> New Accounting Standards: A description of a new accounting standard to be adopted

> Euro Conversion: The status of our program to adapt to the euro currency

> Year 2000 (Y2K): A discussion of how we successfully dealt with the Y2K issue

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Our discussions in the MD&A and other sections of this Annual Report contain forward-looking statements that are based upon our best estimate of the trends we know about or anticipate. Actual results may be different from our estimates. We have described in our 1999 Annual Report on Form 10-K the factors that could change these forward-looking statements.

FINANCIAL HIGHLIGHTS

(Millions of dollars, except per share and ratio data)	**1999**	1998	1997
Revenues	**$ 35,691**	$ 31,707	$ 46,667
Income before special items and cumulative effect of accounting change	**$ 1,214**	$ 894	$ 1,894
Special items	**(37)**	(291)	770
Cumulative effect of accounting change	**—**	(25)	—
Net income	**$ 1,177**	$ 578	$ 2,664
Diluted income per common share *(dollars)*			
Income before special items and cumulative effect of accounting change	**$ 2.21**	$ 1.59	$ 3.45
Special items	**(.07)**	(.55)	1.42
Cumulative effect of accounting change	**—**	(.05)	—
Net income	**$ 2.14**	$ .99	$ 4.87
Cash dividends per common share *(dollars)*	**$ 1.80**	$ 1.80	$ 1.75
Total assets	**$ 28,972**	$ 28,570	$ 29,600
Total debt	**$ 7,647**	$ 7,291	$ 6,392
Stockholders' equity	**$ 12,042**	$ 11,833	$ 12,766
Current ratio	**1.05**	1.07	1.07
Return on average stockholders' equity*	**10.0%**	4.9%	23.5%
Return on average capital employed before special items*	**8.3%**	6.5%	13.0%
Return on average capital employed*	**8.1%**	5.0%	17.3%
Total debt to total borrowed and invested capital	**37.5%**	36.8%	32.3%

*Returns for 1998 exclude the cumulative effect of accounting change (see Note 2 to the financial statements).

INDUSTRY REVIEW

Introduction

International petroleum market conditions changed dramatically during 1999. Over the first few months, crude oil prices were very weak. While economic activity and oil demand were beginning to show signs of increasing, oil supplies were excessive. Then, in April, the Organization of Petroleum Exporting Countries (OPEC) along with other oil producing countries cut output sharply. Oil prices increased and remained strong over the balance of the year.

For 1999, WTI crude oil prices averaged $19.31 per barrel, or 34% above the 1998 average.

Average Price Per Barrel of West Texas Intermediate (WTI) Crude Oil
(Dollars)

Prices in 1999 recovered from historically low levels in 1998.

The increase in crude oil prices boosted revenues from crude oil operations. However, higher crude oil costs, together with other factors such as excess gasoline and distillate stocks, tended to hurt the financial performance of refineries in most markets.

Review of 1999

After slowing sharply in 1998 due to a severe global economic crisis, the rate of world economic growth increased last year. Growth accelerated from a meager 2.3% in 1998 to 2.9% in 1999.

Economic activity varied among regions. The U.S. economy continued to grow at a strong pace with low inflation, due in part to a technology-led surge in labor productivity. Economic expansion in Western Europe also picked up in the second half of the year, benefiting from increased domestic demand and the favorable impact of a weak euro currency on exports.

World economic expansion was reinforced by the beginning of economic recovery in Asia. Several of the key economies in the Asian region, including South Korea, Malaysia, the Philippines, Singapore and Thailand sustained solid economic upturns in 1999. Other regional economies, such as Hong Kong, also turned around. Similarly, Japan, the world's second largest economy, showed signs of emerging from its worst downturn in the post-war period. This improvement was due to extraordinarily low interest rates and increased government spending. However, consumer demand had yet to recover.

The Latin American region, which was hard hit earlier in the year, also began to grow again toward year-end. This renewed growth was propelled by turnarounds in Brazil, Mexico, Argentina and Chile. Moreover, world commodity prices started to rebound from the low levels which resulted from the 1998 economic crisis. This, in turn, spurred economic growth in other areas, particularly the oil producing countries of the Middle East and Africa. In addition, the Russian economy turned upward after many years of decline. This improvement was due to factors such as higher oil prices, increased agricultural output and the substitution of domestically produced goods for imports.

This rebound in economic activity led to a significant increase in the demand for petroleum products worldwide. During 1999, consumption averaged 75.5 million barrels per day (BPD), a 1.3 million BPD, or 1.7% gain over the prior year. This growth, however, was not evenly distributed among regions.

> In the more advanced economies, oil demand rose by 700,000 BPD, boosted by the U.S. and to a lesser extent by Japan

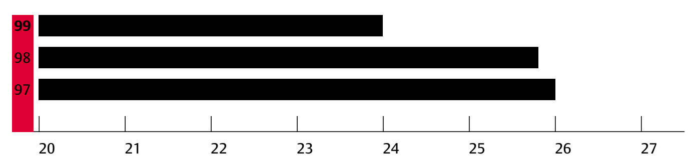
> In the less developed countries, Asian oil demand recovered from its 1998 slump and rose by 500,000 BPD, while growth in Latin America exceeded 100,000 BPD

> Demand in Eastern Europe rose by 100,000 BPD but was offset by an equal decline in the former Soviet Union

> In other regions, demand registered no growth

Demand growth alone may have been insufficient to boost prices. Consequently, OPEC and some non-OPEC producers agreed to cut production. Oil output from these countries, which had been cut twice during 1998, was scaled back further during the early part of 1999 by an additional 1.8 million BPD — bringing the total reduction to a significant 4 million BPD.

Average OPEC Crude Oil Production (Excluding Iraq)
(Millions of barrels a day)



OPEC reduced production dramatically since 1998.

The production curtailment and the resultant tightening balance between supply and demand caused the price of crude oil to soar from its depressed 1998 and early 1999 levels. The market price of West Texas Intermediate (WTI) averaged $19.31 per barrel, an increase of 34% from the prior year. During the final months of 1999, oil prices reached their highest levels in several years and continued to increase in early 2000.

Near-Term Outlook

We expect global economic expansion to accelerate from 2.9% in 1999 to a 3.7% gain this year, reflecting several factors:

> Continued, but slower, gains in the United States as the Federal Reserve moves to moderate growth by raising interest rates

> Continued economic expansion in Western Europe

> Further strengthening in the developing world, particularly the developing nations of Asia and Latin America

> Continued low growth in Russia

On the other hand, the outlook for the large Japanese economy remains clouded by the apparent inability of the economy to grow without strong government spending. Private demand must eventually substitute for government spending if the recovery is to be sustained. Furthermore, Japanese export growth could be jeopardized by a pronounced appreciation in the value of the yen. Accordingly, we expect the Japanese economy to register only minimal growth this year.

With the increase in global economic activity, the demand for crude oil will be greater. An increase in worldwide oil consumption of about 1.6 million BPD is expected. Non-OPEC production should recover considerably and may boost output to levels close to the one million BPD mark. OPEC may therefore choose to relax its quotas and increase production.

The crude oil price outlook is highly uncertain. In the past, high crude oil prices have often encouraged OPEC to increase production sharply, causing prices to drop. Higher petroleum demand and a potential weakening in crude oil costs could benefit downstream margins.

RESULTS OF OPERATIONS

Revenues

Our consolidated worldwide revenues were $35.7 billion in 1999, $31.7 billion in 1998 and $46.7 billion in 1997. Our revenues benefited from higher commodity prices, especially crude oil in the second half of 1999. We also benefited from higher refined product sales volumes in 1999. The decrease in 1998 resulted largely from the accounting for Equilon, a downstream joint venture in the United States we formed in January 1998. Under accounting rules, the significant revenues of the operations we contributed to this joint venture are no longer included in our consolidated revenues. Revenues, costs and expenses of the joint venture are reported net as "equity in income of affiliates" in our income statement.

Sales Revenues – Price/Volume Effects

Our sales revenues were higher in 1999 due to an increase of 38% in our realized crude oil prices. Crude oil and natural gas liquids production, however, was 5% lower, due to natural field declines and asset sales in the U.S. and temporary operating problems in the U.K.

Sales revenues from petroleum products increased in 1999 led by higher prices and stronger international volumes. Volume growth for marine fuel sales benefited from our joint venture with Chevron formed late in 1998.

Our volumes of natural gas sold in 1999 decreased in the U.S. due to lower production and reduced sales of purchased gas. Internationally, we withdrew from the U.K. retail gas marketing business.

Our sales revenues decreased in 1998 due to historically low crude oil, natural gas and refined product prices. Partly offsetting the decline in prices were higher liquids production and sales volumes.

Other Revenues

Other revenues include our equity in the income of affiliates, income from asset sales and interest income. Results for 1999 were lower than 1998 due to reduced interest income on notes and marketable securities and lower asset sales. Equity in income of affiliates in 1999 was consistent with 1998 results. Lower downstream margins in the Caltex Asia-Pacific Region and Motiva's U.S. East and Gulf Coast areas depressed results. However, we realized higher refining margins in Equilon's West Coast operating areas. We also benefited from stronger crude oil prices in our Indonesian producing affiliate.

Results for 1998 show a decrease in other revenues from 1997. Equity in income of affiliates decreased in 1998, mostly due to a decline in Caltex' results. This decline was partly offset by the inclusion of results for Equilon. Income from asset sales was also lower in 1998.

Our share of special charges by our affiliates included in other revenues amounted to $153 million in 1999 and $159 million in 1998. In 1999, these major special charges included refinery asset write-downs in the U.S. and a loss on the sale of an interest in a Japanese affiliate. These charges were reduced by inventory valuation benefits in the U.S. and abroad, as well as tax revaluation benefits in Korea. The 1998 special charges included inventory valuation adjustments, net U.S. alliance formation costs and Caltex restructuring charges.

In 1997, special gains included $416 million from upstream asset sales in the U.K. North Sea and Myanmar.

Costs and Expenses

Costs and expenses from operations were $33.3 billion in 1999, $30.5 billion in 1998 and $42.9 billion in 1997. Higher prices and product volumes increased our cost of goods sold in 1999. While costs have increased, reflecting world oil prices, operating expenses declined in 1999. This improvement reflects our continued emphasis on cost containment and operational efficiency. Similar to the discussion of revenue above, the decrease in both costs and expenses for 1998 is largely due to the accounting treatment for Equilon.

Special items recorded by our subsidiaries increased costs and operating expenses by $121 million in 1999, $382 million in 1998 and $136 million in 1997. Major special items in 1999 included inventory valuation benefits in subsidiaries, which reversed similar charges recorded in 1998 when commodity prices were very depressed. The year 1998 also included higher asset write-downs and employee separation costs.

Asset write-downs in 1999, which increased depreciation, depletion and amortization expense by $87 million, resulted mainly from impairments in our global gas and power segment and our corporate center. Asset write-downs in 1998, which increased depreciation, depletion and amortization expense by $150 million, resulted from impairments primarily in our upstream operations. These and other asset impairments we have recognized since initially applying the provisions of SFAS 121 have been driven by specific events. These include the sale of properties or downward revisions in underground reserve quantities. Impairments have not resulted from changes in prices used to calculate future revenues. In performing our impairment reviews of assets not held for sale, we use our best judgment in estimating future cash flows. This includes our outlook of commodity prices based on our view of supply and demand forecasts and other economic indicators.

Special charges in 1997 were principally for asset write-downs and royalty litigation issues.

Interest expense for 1999 and 1998 increased due mostly to higher average debt levels after a slight decrease in 1997.

During 1999 we kept tight control over expenses. Our success is illustrated by the chart below.

Cash Expenses Per Barrel
(Dollars)

Tight expense control led to a 5% per barrel reduction in 1999.

In 1999, we realized $743 million in pre-tax cost savings and synergy capture, exceeding our year-end 2000 target of $650 million, a full year ahead of schedule. We have identified other opportunities that should capture an additional $400 million in savings by 2001.

Income Taxes

Income tax expense was $602 million in 1999, $98 million in 1998 and $663 million in 1997. The increase in 1999 is mostly due to higher income from international producing operations. These areas are generally high tax jurisdictions. The year 1997 included a $488 million benefit from an IRS settlement.

Income Summary Schedules

The following schedules show after-tax results before and after special items and before the cumulative effect of accounting change. A full discussion of special items is included in our Analysis of Income by Operating Segments.

Income (loss)

(Millions of dollars)	**1999**	1998	1997
Income before special items and cumulative effect of accounting change	**$ 1,214**	$ 894	$ 1,894
Special items:			
Inventory valuation adjustments	**152**	(142)	—
Write-downs of assets	**(157)**	(93)	(41)
Reorganizations, restructurings and employee separation costs	**(74)**	(144)	—
Gains (losses) on major asset sales	**(62)**	20	367
Tax benefits on asset sales	**40**	43	—
Tax issues	**106**	25	480
Royalty issues	**(30)**	—	(36)
Environmental issues	**(12)**	—	—
Total special items	**(37)**	(291)	770
Income before cumulative effect of accounting change	**$ 1,177**	$ 603	$ 2,664

The following schedule further details our results:

Income (loss)

(Millions of dollars)	Before Special Items 1999	Before Special Items 1998	Before Special Items 1997	After Special Items 1999	After Special Items 1998	After Special Items 1997
Exploration and production (upstream)						
United States	**$ 666**	$ 381	$ 1,038	**$ 652**	$ 301	$ 990
International	**386**	181	479	**360**	129	812
Total	**1,052**	562	1,517	**1,012**	430	1,802
Refining, marketing and distribution (downstream)						
United States	**287**	276	312	**208**	221	325
International	**338**	503	524	**370**	332	508
Total	**625**	779	836	**578**	553	833
Global gas and power	**21**	(33)	(46)	**(14)**	(16)	(46)
Total	**1,698**	1,308	2,307	**1,576**	967	2,589
Other business units	**(3)**	(2)	2	**(3)**	(2)	2
Corporate/Non-operating	**(481)**	(412)	(415)	**(396)**	(362)	73
Income before cumulative effect of accounting change	**$ 1,214**	$ 894	$ 1,894	**$ 1,177**	$ 603	$ 2,664

ANALYSIS OF INCOME BY OPERATING SEGMENTS

Upstream

In our upstream business, we explore for, find, produce and sell crude oil, natural gas liquids and natural gas.

Our upstream operations benefited from improved crude oil prices during 1999. The following discussion will focus on how the improved price environment and other business factors affected our earnings. The U.S. results for 1998 and 1997 include some minor Canadian operations which were sold at the end of 1998.

United States Upstream

(Millions of dollars, except as indicated)	1999	1998	1997
Operating income before special items	**$ 666**	$ 381	$ 1,038
Special items:			
Write-downs of assets	**—**	(51)	(31)
Employee separation costs	**(11)**	(29)	—
Gains on major asset sales	**18**	—	26
Royalty issues	**(30)**	—	(36)
Tax issues	**9**	—	(7)
Total special items	**(14)**	(80)	(48)
Operating income	**$ 652**	$ 301	$ 990
Selected Operating Data:			
Net production			
Crude oil and NGL *(thousands of barrels a day)*	**395**	433	396
Natural gas available for sale *(millions of cubic feet a day)*	**1,462**	1,679	1,706
Average realized crude price *(dollars per barrel)*	**$ 14.70**	$ 10.60	$ 17.34
Average realized natural gas price *(dollars per MCF)*	**$ 2.18**	$ 2.00	$ 2.37
Exploratory expenses *(millions of dollars)*	**$ 234**	$ 257	$ 189
Production costs *(dollars per barrel)*	**$ 4.01**	$ 4.07	$ 3.94
Return on average capital employed before special items	**10.5%**	6.0%	20.9%
Return on average capital employed	**10.3%**	4.7%	20.0%

WHAT HAPPENED IN THE UNITED STATES?

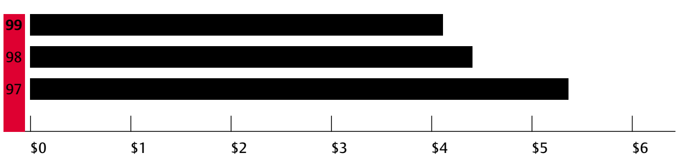
Business Factors

PRICES We benefited from higher prices in 1999, which improved earnings by $342 million. Our average realized crude oil price increased by 39% to $14.70 per barrel. This follows a 39% decrease in 1998 when crude prices plummeted to over 20 year lows in the fourth quarter. Crude oil prices recovered in 1999 as OPEC and several non-OPEC producers implemented cutbacks in production. These production cutbacks, coupled with increasing demand in improving global economies, led to a decline in worldwide inventory levels. Our average realized natural gas price in 1999 increased 9% to $2.18 per thousand cubic feet (MCF). This follows a 16% decrease in 1998.

PRODUCTION Our production declined by 10% in 1999. This decrease was due to natural field declines, asset sales and reduced investment in mature properties consistent with our focus on capital efficiency. In 1998 our production increased by 5%. This was due to our acquisition of heavy oil producer Monterey Resources in November 1997, new production in the Gulf of Mexico and higher production from our Kern River field in California.

Our capital expenditures in 1999 reflect our shift in upstream strategy to pursue high-margin, high-impact projects rather than multiple projects with incremental potential.

U.S. Finding and Development Cost Per Barrel of Oil Equivalent
(Dollars)



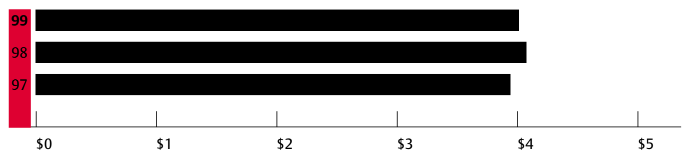
We continue to reduce our per barrel finding and development costs.

EXPLORATORY EXPENSES We expensed $234 million on exploratory activity in 1999. This included a $100 million write-off of investments in the Fuji and McKinley prospects in the Gulf of Mexico. These prospects, initially drilled between 1995 and 1998, were determined to be non-commercial in the fourth quarter of 1999 after appraisal drilling. Our exploratory expenses in 1998 were $257 million, 36% higher than 1997.

Other Factors

Our cash operating expenses decreased in 1999 by 10%. This was a result of cost savings from the restructuring of our worldwide upstream organization. Our production costs per barrel increased in 1998 and then decreased slightly in 1999. Our 1999 production cost per barrel benefited from cost savings but were negatively impacted by production declines of 10%.

U.S. Production Costs Per Barrel
(Dollars)



Cost savings initiatives lowered our per barrel production costs in 1999.

Special Items

Our results for 1999 included a $30 million charge for the settlement of crude oil royalty valuation issues on federal lands and an $11 million charge for employee separation costs. The employee separation costs result from the expansion of our 1998 program. Results for 1998 included a charge for employee separation costs of $29 million. See the section entitled, *Reorganizations, Restructurings and Employee Separation Programs* on page 26 for additional information. During 1999, we also recorded an $18 million gain on asset sales in California and a $9 million production tax refund.

Results for 1998 also included asset write-downs of $51 million for impaired properties in Louisiana and Canada. The impaired Louisiana property represents an unsuccessful enhanced recovery project. We determined in the fourth quarter of 1998 that the carrying value of this property exceeded future undiscounted cash flows. Fair value was determined by discounting expected future cash flows. The Canadian properties were impaired following our decision in October 1998 to exit the upstream business in Canada. These properties were written down to their sales price with the sale closing in December 1998.

Results for 1997 included a charge of $31 million for asset write-downs and a gain of $26 million from the sale of gas properties in Canada. We also recorded charges of $36 million for royalty issues and $7 million for tax issues.

International Upstream

(Millions of dollars, except as indicated)	**1999**	1998	1997
Operating income before special items	**$ 386**	$ 181	$ 479
Special items:			
Write-downs of assets	**—**	(42)	(10)
Employee separation costs	**(2)**	(10)	—
Gains on major asset sales	**—**	—	328
Tax issues	**(24)**	—	15
Total special items	**(26)**	(52)	333
Operating income	**$ 360**	$ 129	$ 812
Selected Operating Data:			
Net production			
Crude oil and NGL *(thousands of barrels a day)*	**490**	497	437
Natural gas available for sale *(millions of cubic feet a day)*	**537**	548	471
Average realized crude price *(dollars per barrel)*	**$ 15.23**	$ 11.20	$ 17.64
Average realized natural gas price *(dollars per MCF)*	**$ 1.34**	$ 1.63	$ 1.66
Exploratory expenses *(millions of dollars)*	**$ 267**	$ 204	$ 282
Production costs *(dollars per barrel)*	**$ 4.37**	$ 3.74	$ 4.30
Return on average capital employed before special items	**10.3%**	5.8%	17.5%
Return on average capital employed	**9.6%**	4.1%	29.7%

WHAT HAPPENED IN THE INTERNATIONAL AREAS?

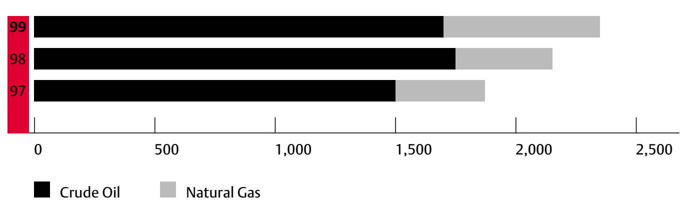
Business Factors

PRICES Our earnings increased by $327 million in 1999 due to the rebound in crude oil prices. Our average crude oil price increased by 36% to $15.23 per barrel. The 1999 recovery in crude oil prices was due to worldwide production cutbacks and improved demand. This improvement follows a decline of 37% in 1998. The trend of lower crude oil prices began in late 1997 and continued throughout 1998 with prices dropping to over 20 year lows in the fourth quarter. Our average realized natural gas price in 1999 declined to $1.34 per MCF, a decrease of 18%. This follows a decrease of 2% in 1998.

Our international average realized crude oil price in 1999 was $15.23 per barrel, an increase of 36%.

PRODUCTION Our production in 1999 declined slightly. We experienced some declines in the U.K. North Sea due to operating problems. In Indonesia we had lower production volumes as higher prices reduced our lifting entitlements for cost recovery under a production sharing agreement. We also experienced lower gas production in Latin America. These declines were partially offset by increased production in the Partitioned Neutral Zone as a result of increased drilling activity and further development of the Karachaganak field in the Republic of Kazakhstan. Our production increased 14% in 1998 due to a full year's production in the U.K. North Sea from the Captain and Erskine fields and new production from the Galley field. Production also grew in the Partitioned Neutral Zone.

International Net Proved Reserves
(Millions of barrels of oil equivalent)



Net proved reserves increased due to the Malampaya and Karachaganak projects.

EXPLORATORY EXPENSES We expensed $267 million on exploratory activity in 1999, an increase of 31%. This included about $50 million for an unsuccessful exploratory well in a new offshore area of Trinidad. Also included is $30 million of prior year drilling expenditures in Thailand, which we wrote off in 1999 after we determined the prospect to be non-commercial. In 1999, our main focus areas were in Nigeria and Brazil. Our exploratory expenses were $204 million in 1998, a decrease of 28%.

Other Factors

Our 1999 cash operating expenses decreased by 3% as a result of continuing cost savings initiatives and the restructuring of our worldwide upstream organization. Our production costs were $4.37 per barrel, an increase of 17%. This increase reflects lower production in Indonesia due to lower entitlement liftings for cost recovery as a result of higher prices.

International Upstream Capital and Exploratory Expenditures
(Billions of dollars)

The growth in international upstream investments shows our focus on high-impact projects.

Special Items
Our results for 1999 included a $24 million charge for prior years' tax issues in the U.K. and a $2 million charge for employee separation costs. The employee separation costs result from the expansion of our 1998 program. Results for 1998 included a charge for employee separation costs of $10 million. See the section entitled, *Reorganizations, Restructurings and Employee Separation Programs* on page 26 for additional information.

Results for 1998 also included a write-down of $42 million for the impairment of our investment in the Strathspey field in the U.K. North Sea. The Strathspey impairment was caused by a downward revision in the fourth quarter of 1998 of the estimated volume of the field's proved reserves. Fair value was determined by discounting expected future cash flows.

Results for 1997 included a $10 million charge for asset write-downs and gains on asset sales of $328 million. These sales included a 15% interest in the Captain field in the U.K. and investments in an Australian pipeline system and the company's Myanmar operations. Also, 1997 included a $15 million prior period tax benefit.

LOOKING FORWARD IN THE WORLDWIDE UPSTREAM
We intend to continue to cost-effectively explore for, develop and produce crude oil and natural gas reserves by focusing on high-margin, high-impact projects. In an effort to boost long-term upstream profitability, we are selling producing properties that no longer fit our business strategy. The cash proceeds from these sales will be reinvested into major upstream projects that offer higher returns. In 2000 we plan to sell producing properties totaling about 100,000 barrels per day of production in the U.S., offshore Trinidad and in the U.K. North Sea. As a result, beginning in 2001 we expect worldwide production to increase by two to three percent annually over the next three to five years. In addition to California, our growth areas of focus include:

> Philippines — where in 1999 we acquired a 45% interest in the Malampaya Deep Water Natural Gas Project. This added 140 million BOE to our proved reserve base and increased our international gas reserves by 30%. Our share of production is anticipated to reach 240 MMCF per day by 2003

> West Africa — where in 1999 we announced the major Agbami oil discovery offshore Nigeria

> U.S. Gulf of Mexico — where we hold both exploration and production acreage and saw the June 1999 start-up of our Gemini Project

> Venezuela — where in 1999 we increased our interest from 20% to 30% in the Hamaca Oil Project

> Kazakhstan — where we hold interests in the Karachaganak and North Buzachi Projects

> Brazil — where in 1999 we signed an agreement with Petrobras, Brazil's national oil company, to become an equity partner in the Campos and Santos exploration and the Frade development areas offshore Brazil and successfully bid on three high potential offshore exploration blocks in Brazil's First License Round

As we implement these growth plans, we will continue to lower our per barrel operating costs through additional cost-savings initiatives.

Our investment in the Malampaya gas project added 140 million BOE to our proved oil and gas reserve base, representing a 30% increase in our international gas reserves.

Downstream
In our downstream business, we refine, transport and sell crude oil and products, such as gasoline, fuel oil and lubricants.

Our U.S. downstream includes our share of operations in Equilon and Motiva. The Equilon area includes western and midwestern refining and marketing operations, and nationwide trading, transportation and lubricants activities. Our 1999 and 1998 results in this area are our share of the earnings of our joint venture with Shell, Equilon, which began operations on January 1, 1998. We have a 44% interest in Equilon. Results for 1997 are for our subsidiary operations in this same area. The Motiva area includes eastern and Gulf Coast refining and marketing operations. Our results for 1999 and the last half of 1998 are our share of the earnings of our joint venture with Shell and Saudi Refining, Inc., Motiva, which began operations on July 1, 1998. We have a 32.5% interest in Motiva. Results for the first half of 1998 and the year 1997 are for our 50% share of our joint venture with Saudi Refining, Inc., Star.

Internationally, our wholly-owned downstream operations are reported separately as Latin America and West Africa and Europe. We also have a 50% interest in a joint venture with Chevron, Caltex, which operates in Africa, Asia, Australia, the Middle East and New Zealand.

In the U.S. and international operations, we also have other businesses, which include aviation and marine product sales, lubricants marketing and other refined product trading activity.

United States Downstream

(Millions of dollars, except as indicated)	**1999**	1998	1997
Operating income before special items	**$ 287**	$ 276	$ 312
Special items:			
Write-downs of assets	**(76)**	—	—
Inventory valuation adjustments	**8**	(34)	—
Reorganizations, restructurings and employee separation costs	**(11)**	(21)	—
Gains on major asset sales	**—**	—	13
Total special items	**(79)**	(55)	13
Operating income	**$ 208**	$ 221	$ 325
Selected Operating Data:			
Refinery input *(thousands of barrels a day)*	**671**	698	747
Refined product sales *(thousands of barrels a day)*	**1,377**	1,203	1,022
Return on average capital employed before special items	**11.3%**	9.6%	9.8%
Return on average capital employed	**8.2%**	7.7%	10.2%

WHAT HAPPENED IN THE UNITED STATES?

Equilon These operations contributed $288 million to our 1999 operating earnings before special items. We achieved higher earnings in 1999 from improved West Coast refining margins as a result of industry refinery outages earlier in the year. We also benefited from improved utilization of the Martinez refinery, strong transportation results from higher throughput and realization of cost savings and synergies. These include improved efficiency of work processes, reduction of supply costs, sharing best practices, capitalizing on logistical and trading opportunities and greater utilization of proprietary pipelines. These improved results in 1999 were partly offset by operating problems at the Puget Sound refinery earlier in the year and weak marketing margins as pump prices lagged behind increases in gasoline spot prices. Our sales volumes improved in 1999 due to increased trading activity.

The 1998 earnings were flat when compared with 1997. Strong transportation and lubricants earnings as well as cost and expense reductions were offset by the effects of significant downtime at certain refineries, lower margins and interest expense. Refined product sales volumes increased. This included 4% growth in Texaco-branded gasoline sales.

Our share of the U.S. affiliates' pre-tax cost savings and synergy capture was $326 million in 1999.

Motiva These operations contributed only $12 million to our 1999 operating income before special items. Our 1999 results were lower than 1998. They were negatively impacted by weak refining and marketing margins on the East and Gulf Coasts due to the inability to pass along rising crude costs and high industry-wide refined product inventory levels. These weaknesses were partly offset by improved refinery reliability and cost savings and synergies that were achieved by Motiva. These include reduction of fuel additive supply costs, improved efficiency of work processes, improved asset utilization and sharing best practices.

The 1998 earnings were lower due to refinery downtime coupled with lower refining margins. Refined product sales were higher as a result of our joint venture and an increase in Texaco-branded gasoline sales. The year 1997 benefited from improved Gulf Coast refining margins.

Special Items

Results for 1999 and 1998 included net special charges of $79 million and $55 million, representing our share of special items recorded by our U.S. alliances. Results for 1997 included a gain of $13 million from the sale of our credit card business.

The 1999 charge included $76 million for the write-downs of assets to their estimated sales values by Equilon for the intended sales of its El Dorado and Wood River refineries. Equilon completed the sale of the El Dorado refinery to Frontier Oil Corporation in November 1999, and is continuing to seek a purchaser for the Wood River refinery.

Our 1999 results also included an inventory valuation benefit of $8 million due to higher 1999 inventory values. This follows a 1998 charge of $34 million to reflect lower market prices on December 31, 1998 for inventories of crude oil and refined products. We value inventories at the lower of cost or market, after initially recording at cost. Inventory valuation adjustments are reversed when prices recover and the associated physical units of inventory are sold.

Our 1999 and 1998 results included net charges of $11 million and $21 million for reorganizations, restructurings and employee separation costs. The 1999 charge represents dismantling expenses at a closed refinery, an adjustment to the Anacortes refinery sale and employee separation costs from the expansion of Equilon's and Motiva's 1998 separation programs. The 1998 net charge was for U.S. alliance formation issues. This net charge included $52 million for employee separation costs and $45 million for write-downs of closed facilities and surplus equipment to their net realizable value. These facilities included a refinery in Texas, lubricant plants in various states, a sales terminal in Louisiana and research facilities and equipment in Texas and New York. Also included in net charges were gains of $76 million from the Federal Trade Commission-mandated sale of the Anacortes refinery and Plantation pipeline.

International Downstream

(Millions of dollars, except as indicated)	**1999**	1998	1997
Operating income before special items	**$ 338**	$ 503	$ 524
Special items:			
Inventory valuation adjustments	**144**	(108)	—
Write-downs of assets	**(23)**	—	—
Reorganizations, restructurings and employee separation costs	**(41)**	(63)	—
Losses on major asset sales	**(80)**	—	—
Tax issues	**32**	—	(16)
Total special items	**32**	(171)	(16)
Operating income	**$ 370**	$ 332	$ 508
Selected Operating Data:			
Refinery input *(thousands of barrels a day)*	**820**	832	804
Refined product sales *(thousands of barrels a day)*	**1,844**	1,685	1,563
Return on average capital employed before special items	**5.6%**	8.2%	9.2%
Return on average capital employed	**6.1%**	5.4%	8.9%

WHAT HAPPENED IN THE INTERNATIONAL AREAS?

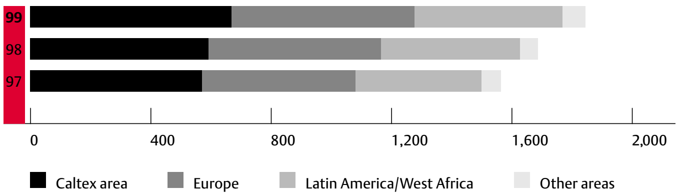
Latin America and West Africa Our operations in Latin America and West Africa contributed 66% of our 1999 operating income before special items. Results in 1999 were lower than 1998 as they reflected a squeeze on refining margins as escalating crude costs outpaced product price increases. Our results were also adversely affected by depressed marketing margins and lower volumes in Brazil due to poor economic conditions and related currency devaluation. Partially offsetting these conditions was an overall 7% increase in refined product sales volume led by our Caribbean and Central American operations. In 1998, earnings increased due to higher refined product sales volumes from service station acquisitions and the expansion of our industrial customer base.

Europe Our European operations contributed 26% of our 1999 operating income before special items. Results for 1999 were lower due to poor refining margins. Product price increases failed to keep pace with escalating crude costs. A 6% increase in refined product sales volumes helped to offset the squeeze on margins. In 1998, earnings increased significantly from improved refining and marketing margins. Additionally, during 1998 we grew our refined product sales volumes by increasing retail outlets and obtaining new commercial business.

Caltex Our results for Caltex in 1999 before special items were $28 million. These results were lower than 1998. Results were adversely affected by depressed refining and marketing margins. This was caused by the inability to recover rapidly escalating crude oil costs in the marketplace and product oversupply. These declines were partially offset by an inventory drawdown benefit and gains from the sale of marketable securities. There were also lower currency losses from reduced volatility and generally improved economic conditions. In 1998, our results for Caltex were $156 million lower than 1997. This was mainly due to negative currency impacts of $204 million. Excluding currency effects, our results for Caltex improved in 1998 due to higher margins and volumes.

In the Caltex area, most of our operations have a net liability exposure, which creates currency losses when foreign currencies strengthen against the U.S. dollar and currency gains when these currencies weaken against the U.S. dollar. Effective October 1, 1997, Caltex changed the functional currency used to account for operations in Korea and Japan to the U.S. dollar.

International Refined Product Sales
(Thousands of barrels a day)



International sales volumes increased by more than 9% in 1999.

Special Items
Results for 1999 included net special benefits of $32 million. Results for 1998 and 1997 included net special charges of $171 million and $16 million. Special items relating to Caltex represent our 50 percent share.

Results for 1999 included inventory valuation benefits of $144 million due to higher 1999 inventory values. This follows a 1998 charge of $108 million to reflect lower market prices on December 31, 1998 for inventories of crude oil and refined products, as well as additional charges recorded in prior years. We value inventories at the lower of cost or market, after initially recording at cost. Inventory valuation adjustments are reversed when prices recover and the associated physical units of inventory are sold.

Results for 1999 included a charge of $23 million for the write-downs of assets. These write-downs on properties to be disposed of include $10 million for marketing assets in our subsidiary in Poland and $13 million for assets in our Caltex operations.

Our 1999 results included a $9 million charge for employee separation costs for our subsidiaries operating in Europe and Latin America. These costs resulted from the expansion of our 1998 program. Results for 1998 included a charge for employee separation costs of $20 million. See the section entitled, *Reorganizations, Restructurings and Employee Separation Programs* on page 26 for additional information.

Results for 1999 also included charges of $80 million related to our share of the Caltex loss on the sale of its equity interest in Koa Oil Company, Limited, including deferred currency translation net losses. Additionally, our results for 1999 included a Caltex Korean tax benefit of $54 million due to asset revaluation and $22 million for prior year tax charges in the U.K. Results for 1997 included a charge of $16 million primarily for a European deferred tax adjustment.

Results for 1999 and 1998 included other charges of $32 million and $43 million, representing our share of a Caltex reorganization program. The 1999 charge represented continued expenses related to the 1998 program. The 1998 charge resulted from their decision to structure their organization along functional lines and to reduce costs by establishing a shared service center in the Philippines. In implementing this change, Caltex also relocated its headquarters from Dallas to Singapore. About $35 million of the 1998 charge relates to severance and other retirement benefits for about 200 employees not relocating, write-downs of surplus furniture and equipment and other costs. The balance of the charge is for severance costs in other affected areas and amounts spent in relocating employees to the new shared service center.

LOOKING FORWARD IN THE WORLDWIDE DOWNSTREAM
We intend to do the following in our worldwide downstream:

> Reduce our exposure to refining

> Continue to achieve lower costs and capture synergies

> Focus on business opportunities in areas of trading, transportation and lubricants

> Pursue marketing growth opportunities in selected areas

Global Gas and Power

(Millions of dollars, except as indicated)	**1999**	1998	1997
Operating income (loss) before special items	**$ 21**	$ (33)	$ (46)
Special items:			
Write-downs of assets	**(32)**	—	—
Employee separation costs	**(3)**	(3)	—
Gain on major asset sale	**—**	20	—
Total special items	**(35)**	17	—
Operating loss	**$ (14)**	$ (16)	$ (46)
Natural gas sales *(millions of cubic feet a day)*	**3,134**	3,764	3,452
Net power sales *(gigawatt hours)*	**4,353**	4,395	4,185

Global Gas and Power includes marketing of natural gas and natural gas liquids, gas processing plants, pipelines, power generation plants, gasification licensing and equity plants, and our hydrocarbons-to-liquids and fuel cell technology units. Gasification is a proprietary technology that converts low value hydrocarbons into useful synthesis gas for the chemical, refining and power industries. During 1999, responsibility for these activities was combined under a single senior executive, forming the Global Gas and Power segment. Prior period information has been restated to reflect this change.

Our gas marketing operating results in 1999 benefited from improved natural gas liquids margins. Our 1999 results also included gains on normal asset sales and lower operating expenses. The asset sales included our interest in a U.K. retail gas marketing operation and the sale of a U.S. gas gathering pipeline.

Results for 1998 were adversely affected by losses associated with our start-up wholesale and retail marketing activities in the U.K. We exited the U.K. wholesale gas marketing business in October 1998. Weak natural gas and natural gas liquids margins in the U.S. also contributed to the poor results. Milder than normal temperatures reduced demand and squeezed margins.

Our operating results for the power and gasification business in 1999 benefited from higher gasification licensing revenues and cogeneration income. This was partially offset by lower margins from Indonesian geothermal activities and the non-recurring recoupment of development costs in 1998. The lower Indonesian geothermal margins are due to higher costs and lower revenues caused by regional economic weakness.

Special Items

Results for both 1999 and 1998 included charges of $3 million for employee separation costs. The 1999 charge resulted from the expansion of our 1998 program. See the section entitled, *Reorganizations, Restructurings and Employee Separation Programs* on page 26 for additional information.

Our 1999 results also included charges of $32 million for asset write-downs from the impairment of certain gas plants in Louisiana. We determined in the fourth quarter of 1999 that as a result of declining gas volumes available for processing, the carrying value of these plants exceeded future undiscounted cash flows. Fair value was determined by discounting expected future cash flows. Our 1998 results also included a gain of $20 million on the sale of an interest in our Discovery pipeline affiliate.

LOOKING FORWARD IN GLOBAL GAS AND POWER

We believe there is great promise with emerging gas and power technologies. Accordingly, we are pursuing opportunities utilizing gasification, hydrocarbons-to-liquids and fuel cell technologies. We continue to develop power projects in conjunction with our exploration, production and refining needs. Our future plans include:

> Developing power projects where significant reserves of natural gas require commercialization

> Expanding our gasification technology to commercialize this environmentally friendly technology

> Using our technology to develop opportunities in the fuel cell and hydrocarbons-to-liquids businesses

Effective March 1, 2000, we will form a joint venture with a subsidiary of Enron Corp. to combine the companies' intrastate pipeline and storage businesses in southeast Louisiana.

Other Business Units

(Millions of dollars)	**1999**	1998	1997
Operating income (loss)	**$ (3)**	$ (2)	$ 2

Our other business units mainly include our insurance operations. There were no significant items in our three-year results.

Corporate/Non-operating

(Millions of dollars)	**1999**	1998	1997
Results before special items	**$ (481)**	$ (412)	$ (415)
Special items:			
Write-downs of assets	**(26)**	—	—
Employee separation costs	**(6)**	(18)	—
Tax benefits on asset sales	**40**	43	—
Tax issues	**89**	25	488
Environmental issues	**(12)**	—	—
Total special items	**85**	50	488
Total Corporate/Non-operating	**$ (396)**	$ (362)	$ 73

Corporate/Non-operating

Corporate/Non-operating includes our corporate center and financing activities. The year 1999 reflects higher interest expense resulting from increases in debt levels. Results for 1998 included lower overhead and tax expense. Higher interest income was mostly offset by interest expense from higher average debt levels.

Special Items

Results for 1999 included tax benefits of $89 million. These are associated with favorable determinations in the fourth quarter on prior years' tax issues. Results for 1999 and 1998 included tax benefits of $40 million and $43 million from the sales of interests in a subsidiary. Additionally, results for 1998 included a benefit of $25 million to adjust for prior years' federal tax liabilities. The year 1997 included a tax benefit of $488 million from an IRS settlement.

Our 1999 results also included a $6 million charge for employee separation costs. These costs resulted from the expansion of our 1998 program. Results for 1998 included a charge for employee separations of $18 million. See the section entitled, *Reorganizations, Restructurings and Employee Separation Programs* on page 26 for additional information.

We also recorded in 1999 charges of $12 million for environmental issues and $26 million for the impairment of assets and related disposal costs. The assets write-downs resulted from our joint plan with state and local agencies to convert for third-party industrial use idle facilities, formerly used in research activities. The facilities and equipment were written down to their appraised values.

OTHER ITEMS

Liquidity and Capital Resources

INTRODUCTION The Statement of Consolidated Cash Flows on page 37 reports the changes in cash balances for the last three years, and summarizes the inflows and outflows of cash between operating, investing and financing activities. Our cash requirements are met by cash from operations, supplemented by outside borrowings and the proceeds from the sale of non-strategic assets.

The main components of cash flows are:

INFLOWS *Cash from operating activities* represents net income adjusted for non-cash charges or credits, such as depreciation, depletion and amortization, and changes in working capital and other balances. Cash from operating activities excludes exploratory expenses, which we show as a cash outflow from investing activities. Operating cash flows for 1999 of $3,169 million benefited from higher commodity prices and our expense reduction programs. For more detailed insight into our financial and operational results, see Analysis of Income by Operating Segments on the preceding pages.

New borrowings in 1999 reflect a net increase of $290 million compared to a net increase of $1,052 million in 1998. During the year, we borrowed $1,668 million from our existing "shelf" registration, including $1,268 million under our medium-term note program. We decreased our commercial paper by $518 million during the year, to $1,099 million at year-end. See Note 9 to the financial statements for total outstanding debt, including 1999 borrowings.

After December 31, 1999, we issued an additional $530 million under our medium-term note program to refinance existing short-term debt. As a result, our total remaining capacity under our "shelf" registration is $1,445 million, covering possible issuances of both debt and equity securities.

We maintain strong credit ratings and access to global financial markets providing us flexibility to borrow funds at low capital costs.

Our senior debt is rated A+ by Standard & Poor's Corporation and A1 by Moody's Investors Service. Our U.S. commercial paper is rated A-1 by Standard & Poor's and Prime-1 by Moody's. These ratings denote high quality investment grade securities. Our debt has an average maturity of 10 years and a weighted average interest rate of 7.0%. We also maintain $2.05 billion in revolving credit facilities, which remain unused, to provide liquidity and to support our commercial paper program.

Other net cash inflows in 1999 represent proceeds from the sale of non-strategic assets of $321 million, net sales/maturities of investment instruments of $346 million and the collection of notes receivable from an affiliate of $101 million.

OUTFLOWS *Capital and exploratory expenditures (Capex)* were $2,957 million in 1999 — The section on page 27 describes in more detail the uses of our Capex dollars.

Payments of dividends were $1,047 million in 1999 — $964 million to common, $28 million to preferred and $55 million to shareholders who hold a minority interest in Texaco subsidiary companies.

The following year-end table reflects our key financial indicators:

(Millions of dollars, except as indicated)	**1999**	1998	1997
Current ratio	**1.05**	1.07	1.07
Total debt	**$ 7,647**	$ 7,291	$ 6,392
Average years debt maturity	**10**	10	11
Average interest rates	**7.0%**	7.0%	7.2%
Minority interest in subsidiary companies	**$ 710**	$ 679	$ 645
Stockholders' equity	**$ 12,042**	$ 11,833	$ 12,766
Total debt to total borrowed and invested capital	**37.5%**	36.8%	32.3%

OUTLOOK We consider our financial position to be sufficiently strong to meet our anticipated future financial requirements. Our financial policies and procedures afford us flexibility to meet the changing landscape of our financial environment. Cash required to service debt maturities in 2000 is projected to be $1,450 million. However, we intend to refinance these maturities.

In 2000, we feel our *cash from operating activities* and *cash proceeds from asset sales,* coupled with our *borrowing* capacity, will allow us to meet our *Capex* program. Additionally, we will continue to provide a sustained return to our shareholders in the form of dividends.

MANAGING MARKET RISK We are exposed to the following types of market risks:

> The price of crude oil, natural gas and petroleum products

> The value of foreign currencies in relation to the U.S. dollar

> Interest rates

We use contracts such as futures, swaps and options in managing our exposure to these risks. We have written policies that govern our use of these instruments and limit our exposure to market and counterparty risks. These arrangements do not expose us to material adverse effects. See Notes 9, 14 and 15 to the financial statements and Supplemental Market Risk Disclosures on page 63 for additional information.

Reorganizations, Restructurings and Employee Separation Programs

In the fourth quarter of 1998, we announced that we were reorganizing several of our operations and implementing other cost-cutting initiatives. The principal units affected were our worldwide upstream; our international downstream, principally our marketing operations in the United Kingdom and Brazil and our refining operations in Panama; global gas marketing, now included as part of our global gas and power operating segment; and our corporate center. We accrued $115 million ($80 million, net of tax) for employee separations, curtailment costs and special termination benefits associated with these announced restructurings in the fourth quarter of 1998. During the second quarter of 1999, we expanded the employee separation programs and recorded an additional provision of $48 million ($31 million, net of tax). For the most part, separation accruals are shown as operating expenses in the Statement of Consolidated Income.

The following table identifies each of our four restructuring initiatives. It provides the provision recorded in the fourth quarter of 1998 and the additional provision recorded in the second quarter of 1999. It also shows the deductions made through December 31, 1999 and the remaining obligations as of December 31, 1999. These deductions include cash payments of $124 million and transfers to long-term obligations of $12 million. We will pay the remaining obligations in future periods in accordance with plan provisions.

	Provision Recorded in		**Deductions made through December 31, 1999**	**Remaining Obligations as of December 31, 1999**
(Millions of dollars)	1998	**1999**		
Worldwide upstream	$ 56	**$ 20**	**$ (71)**	**$ 5**
International downstream	25	**13**	**(26)**	**12**
Global gas and power	5	**4**	**(7)**	**2**
Corporate center	29	**11**	**(32)**	**8**
Total	$ 115	**$ 48**	**$ (136)**	**$ 27**

At the time we initially announced these programs, we estimated that over 1,400 employee reductions would result. Employee reductions of 800 in worldwide upstream, 300 in international downstream, 100 in global gas and power and 200 in our corporate center were expected. During the second quarter of 1999, we expanded the program by almost 1,100 employees, comprised of 600 employees in worldwide upstream, 250 employees in international downstream, 100 employees in global gas and power and 150 employees in our corporate center. Through December 31, 1999, employee reductions totaled 1,375 in worldwide upstream, 518 in international downstream, 165 in global gas and power, and 404 in our corporate center.

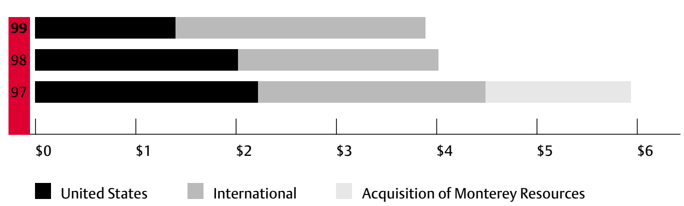
As a result of our reorganizations and restructurings, we captured significant annual pre-tax cost and expense savings and synergies. We captured $236 million in worldwide upstream, $44 million in international downstream, $32 million in global gas and power and $59 million in our corporate center. These savings include lower people-related and operating expenses.

Additionally, our major affiliates have also captured significant annual pre-tax cost and expense savings and synergies, as a result of their own reorganizations. Our share of these savings from our U.S. downstream joint ventures, Equilon and Motiva, was $326 million, representing lower people-related expenses and reductions in cash operating expenses due to efficiencies. We realized $19 million in annual pre-tax cost savings, representing our share of the Caltex reorganization. These savings represent lower people-related expenses. We also captured $27 million in annual pre-tax cost reductions from our worldwide Fuel and Marine Marketing joint venture with Chevron, representing our share of reductions in operating costs and expenses due to efficiencies.

Capital and Exploratory Expenditures

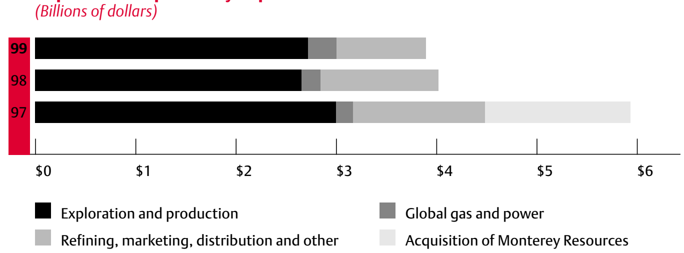
1999 ACTIVITY Worldwide capital and exploratory expenditures, including our share of affiliates, were $3.9 billion for 1999, $4.0 billion for 1998 and $5.9 billion for 1997. The year 1997 included the $1.4 billion acquisition of Monterey Resources Inc., a producing company with operations primarily in California. Texaco's 1999 expenditures include acquisitions of and increased ownership interests in upstream projects. Expenditures were geographically and functionally split as follows:

Capital and Exploratory Expenditures — Geographical
(Billions of dollars)



Our investment in Malampaya contributed to the increase in international spending in 1999.

Capital and Exploratory Expenditures — Functional
(Billions of dollars)



We continue emphasis on exploration and production projects.

EXPLORATION AND PRODUCTION Significant areas of investment included:

> Exploration and development work in West Africa where we announced the major Agbami oil discovery offshore Nigeria in 1999

> Acquisition of a 45% interest in the Malampaya Deep Water Natural Gas Project in the Philippines

> Increased ownership interest in the Venezuelan Hamaca Oil Project from 20% to 30%

> Development work in Kazakhstan on the Karachaganak and North Buzachi fields

> Acquisition of exploration leases in the Brazilian Campos and Santos Basins

REFINING, MARKETING AND DISTRIBUTION AND OTHER Investment activities included:

> Reduced spending by Equilon and Motiva on refining

> Increased service station construction and renovation in the Caribbean

> Increased global gasification and power projects

The following table details our capital and exploratory expenditures:

			1999			1998			1997
(Millions of dollars)	**U.S.**	**Inter-national**	**Total**	U.S.	Inter-national	Total	U.S.	Inter-national	Total
Exploration and production									
Exploratory expenses	**$ 234**	**$ 267**	**$ 501**	$ 257	$ 204	$ 461	$ 189	$ 282	$ 471
Capital expenditures	**666**	**1,556**	**2,222**	1,179	1,015	2,194	2,854*	1,095	3,949*
Total exploration and production	**900**	**1,823**	**2,723**	1,436	1,219	2,655	3,043	1,377	4,420
Refining, marketing and distribution	**379**	**487**	**866**	431	717	1,148	427	848	1,275
Global gas and power	**103**	**176**	**279**	124	61	185	149	34	183
Other	**18**	**7**	**25**	29	2	31	50	2	52
Total	**$ 1,400**	**$ 2,493**	**$ 3,893**	$ 2,020	$ 1,999	$ 4,019	$ 3,669	$ 2,261	$ 5,930
Total, excluding affiliates	**$ 1,012**	**$ 2,051**	**$ 3,063**	$ 1,528	$ 1,496	$ 3,024	$ 3,421	$ 1,718	$ 5,139

*Capital expenditures for 1997 include $1,448 million for the acquisition of Monterey Resources Inc.

2000 AND BEYOND

Spending for the year 2000 is expected to rise to $4.7 billion, an increase of $800 million over 1999 levels. In the upstream, spending is being allocated to our large impact producing projects in West Africa, Venezuela, Kazakhstan, the Philippines and the U.K. North Sea. Major exploration programs are underway in our key focus areas of Nigeria, Brazil and the deepwater Gulf of Mexico. International marketing will increase spending in the rapidly growing Caribbean area. Modest increases in spending are also anticipated for our international refinery system, particularly the Pembroke refinery in Wales. However, refining expenditures are generally being held at maintenance levels. Our global gas and power business is growing and has identified additional power generation and gasification projects as well as natural gas business opportunities.

Environmental Matters

The cost of compliance with federal, state and local environmental laws in the U.S. and international countries continues to be substantial. Using definitions and guidelines established by the American Petroleum Institute, our 1999 environmental spending was $633 million. This includes our equity share in the environmental expenditures of our major affiliates, Equilon, Motiva and the Caltex Group of Companies. The following table provides our environmental expenditures for the past three years:

(Millions of dollars)	**1999**	1998	1997
Capital expenditures	**$ 118**	$ 175	$ 162
Non-capital:			
Ongoing operations	**391**	495	538
Remediation	**98**	93	79
Restoration and abandonment	**26**	44	46
Total environmental expenditures	**$ 633**	$ 807	$ 825

CAPITAL EXPENDITURES

Our spending for capital projects in 1999 was $118 million. These expenditures were made to comply with clean air and water regulations as well as waste management requirements. Worldwide capital expenditures projected for 2000 and 2001 are $91 million and $121 million.

ONGOING OPERATIONS

In 1999, environmental expenses charged to current operations were $391 million. These expenses related largely to the production of cleaner-burning gasoline and the management of our environmental programs.

REMEDIATION

Remediation Costs and Liabilities Our worldwide remediation expenditures in 1999 were $98 million. This included $12 million spent on the remediation of Superfund waste sites. At the end of 1999, we had liabilities of $391 million for the estimated cost of our known environmental liabilities. This includes $46 million for the cleanup of Superfund waste sites. We have accrued for these remediation liabilities based on currently available facts, existing technology and presently enacted laws and regulations. It is not possible to project overall costs beyond amounts disclosed due to the uncertainty surrounding future developments in regulations or until new information becomes available.

Superfund Sites Under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), the U.S. Environmental Protection Agency (EPA) and other regulatory agencies have identified us as a potentially responsible party (PRP) for cleanup of Superfund waste sites. We have determined that we may have potential exposure, though limited in most cases, at 178 Superfund waste sites. Of these sites, 104 are on the EPA's National Priority List. Under Superfund, liability is joint and several, that is, each PRP at a site can be held liable individually for the entire cleanup cost of the site. We are, however, actively pursuing the sharing of Superfund costs with other identified PRPs. The sharing of these costs is on the basis of weight, volume and toxicity of the materials contributed by the PRP.

RESTORATION AND ABANDONMENT COSTS AND LIABILITIES

Expenditures in 1999 for restoration and abandonment of our oil and gas producing properties amounted to $26 million. At year-end 1999, accruals to cover the cost of restoration and abandonment were $911 million.

We make every reasonable effort to fully comply with applicable governmental regulations. Changes in these regulations as well as our continuous re-evaluation of our environmental programs may result in additional future costs. We believe that any mandated future costs would be recoverable in the marketplace, since all companies within our industry would be facing similar requirements. However, we do not believe that such future costs would be material to our financial position or to our operating results over any reasonable period of time.

New Accounting Standards

In June 1998, the Financial Accounting Standards Board (FASB) issued SFAS 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS 133 establishes new accounting rules and disclosure requirements for most derivative instruments and hedge transactions. In June 1999, the FASB issued SFAS 137, which deferred the effective date of SFAS 133. We will adopt SFAS 133 effective January 1, 2001 and are currently assessing the effects of adoption.

Euro Conversion

On January 1, 1999, 11 of the 15 member countries of the European Union established fixed conversion rates between their existing currencies and one common currency — the euro. The euro began trading on world currency exchanges at that time and may be used in business transactions. On January 1, 2002, new euro-denominated bills and coins will be issued, and legacy currencies will be completely withdrawn from circulation by June 30 of that year.

Prior to introduction of the euro, our operating subsidiaries affected by the euro conversion completed computer systems upgrades and fiscal and legal due diligence to ensure our euro readiness. Computer systems have been adapted to ensure that all our operating subsidiaries have the capability to comply with necessary business requirements and customer/supplier preferences. Legal due diligence was conducted to ensure post-euro continuity of contracts, and fiscal reviews were completed to ensure compatibility with our banking relationships. We, therefore, experienced no major impact on our current business operations as a result of the introduction of the euro.

We continue to review our marketing and operational policies and procedures to ensure our ability to continue to successfully conduct all aspects of our business in this new, price-transparent market. We believe that the euro conversion will not have a material adverse impact on our financial condition or results of operations.

Year 2000 (Y2K)

We encountered no major operating or other problems due to the Y2K issue. The Y2K issue concerned the inability of some information and technology-based operating systems to properly recognize and process date-sensitive information beyond December 31, 1999. Since we began addressing this issue in 1995, we assessed over 45,000 systems for potential problems. By November 1, 1999, we completed modifying or upgrading all of our critical and essential systems and gained assurances that our major affiliates were prepared for the Y2K rollover. We also completed our review of critical suppliers and customers, developed contingency plans, and established an Early Alert System to monitor the Y2K status of our key facilities around the world during the rollover.

During the year 1999 and the first few weeks of 2000, we spent about $22 million on Y2K issues, bringing our total spent since 1995 to $59 million. We do not anticipate expending additional funds on Y2K related activities.

Description of Significant Accounting Policies

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements consist of the accounts of Texaco Inc. and subsidiary companies in which we hold direct or indirect voting interest of more than 50%. Intercompany accounts and transactions are eliminated.

The U.S. dollar is the functional currency of all our operations and substantially all of the operations of affiliates accounted for on the equity method. For these operations, translation effects and all gains and losses from transactions not denominated in the functional currency are included in income currently, except for certain hedging transactions. The cumulative translation effects for the equity affiliates using functional currencies other than the U.S. dollar are included in the currency translation adjustment in stockholders' equity.

USE OF ESTIMATES

In preparing Texaco's consolidated financial statements in accordance with generally accepted accounting principles, management is required to use estimates and judgment. While we have considered all available information, actual amounts could differ from those reported as assets and liabilities and related revenues, costs and expenses and the disclosed amounts of contingencies.

REVENUES

We recognize revenues for crude oil, natural gas and refined product sales at the point of passage of title specified in the contract. We record revenues on forward sales where cash has been received to deferred income until title passes.

CASH EQUIVALENTS

We generally classify highly liquid investments with a maturity of three months or less when purchased as cash equivalents.

INVENTORIES

We value inventories at the lower of cost or market, after initially recording at cost. For virtually all inventories of crude oil, petroleum products and petrochemicals, cost is determined on the last-in, first-out (LIFO) method. For other merchandise inventories, cost is generally on the first-in, first-out (FIFO) method. For materials and supplies, cost is at average cost.

INVESTMENTS AND ADVANCES

We use the equity method of accounting for investments in certain affiliates owned 50% or less, including corporate joint ventures, limited liability companies and partnerships. Under this method, we record equity in the pre-tax income or losses of limited liability companies and partnerships, and equity in the net income or losses of corporate joint-venture companies currently in Texaco's revenues, rather than when realized through dividends or distributions.

We record the net income of affiliates accounted for at cost in net income when realized through dividends.

We account for investments in debt securities and in equity securities with readily determinable fair values at fair value if classified as available-for-sale.

PROPERTIES, PLANT AND EQUIPMENT AND DEPRECIATION, DEPLETION AND AMORTIZATION

We follow the "successful efforts" method of accounting for our oil and gas exploration and producing operations.

We capitalize as incurred the lease acquisition costs of properties held for oil, gas and mineral production. We expense as incurred exploratory costs other than wells. We initially capitalize exploratory wells, including stratigraphic test wells, pending further evaluation of whether economically recoverable proved reserves have been found. If such reserves are not found, we charge the well costs to exploratory expenses. For locations not requiring major capital expenditures, we record the charge within one year of well completion. We capitalize intangible drilling costs of productive wells and of development dry holes, and tangible equipment costs. Also capitalized are costs of injected carbon dioxide related to development of oil and gas reserves.

We base our evaluation of impairment for properties, plant and equipment intended to be held on comparison of carrying value against undiscounted future net pre-tax cash flows, generally based on proved developed reserves. If an impairment is identified, we adjust the asset's carrying amount to fair value. We generally account for assets to be disposed of at the lower of net book value or fair value less cost to sell.

We amortize unproved oil and gas properties, when individually significant, by property using a valuation assessment. We generally amortize other unproved oil and gas properties on an aggregate basis over the average holding period, for the portion expected to be non-productive. We amortize productive properties and other tangible and intangible costs of producing activities principally by field. Amortization is based on the unit-of-production basis by applying the ratio of produced oil and gas to estimated recoverable proved oil and gas reserves. We include estimated future restoration and abandonment costs in determining amortization and depreciation rates of productive properties.

We apply depreciation of facilities other than producing properties generally on the group plan, using the straight-line method, with composite rates reflecting the estimated useful life and cost of each class of property. We depreciate facilities not on the group plan individually by estimated useful life using the straight-line method. We exclude estimated salvage value from amounts subject to depreciation. We amortize capitalized non-mineral leases over the estimated useful life of the asset or the lease term, as appropriate, using the straight-line method.

We record periodic maintenance and repairs at manufacturing facilities on the accrual basis. We charge to expense normal maintenance and repairs of all other properties, plant and equipment as incurred. We capitalize renewals, betterments and major repairs that materially extend the useful life of properties and record a retirement of the assets replaced, if any.

When capital assets representing complete units of property are disposed of, we credit or charge to income the difference between the disposal proceeds and net book value.

ENVIRONMENTAL EXPENDITURES

When remediation of a property is probable and the related costs can be reasonably estimated, we accrue the expenses of environmental remediation costs and record them as liabilities. Recoveries or reimbursements are recorded as an asset when receipt is assured. We expense or capitalize other environmental expenditures, principally maintenance or preventive in nature, as appropriate.

DEFERRED INCOME TAXES

We determine deferred income taxes utilizing a liability approach. The income statement effect is derived from changes in deferred income taxes on the balance sheet. This approach gives consideration to the future tax consequences associated with differences between financial accounting and tax bases of assets and liabilities. These differences relate to items such as depreciable and depletable properties, exploratory and intangible drilling costs, non-productive leases, merchandise inventories and certain liabilities. This approach gives immediate effect to changes in income tax laws upon enactment.

We reduce deferred income tax assets by a valuation allowance when it is more likely than not (more than 50%) that a portion will not be realized. Deferred income tax assets are assessed individually by type for this purpose. This process requires the use of estimates and judgment, as many deferred income tax assets have a long potential realization period.

We do not make provision for possible income taxes payable upon distribution of accumulated earnings of foreign subsidiary companies and affiliated corporate joint-venture companies when such earnings are deemed to be permanently reinvested.

ACCOUNTING FOR CONTINGENCIES

Certain conditions may exist as of the date financial statements are issued, which may result in a loss to the company, but which will only be resolved when one or more future events occur or fail to occur. Such contingent liabilities are assessed by the company's management and legal counsel. The assessment of loss contingencies necessarily involves an exercise of judgment and is a matter of opinion. In assessing loss contingencies related to legal proceedings that are pending against the company or unasserted claims that may result in such proceedings, the company's legal counsel evaluates the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material liability had been incurred and the amount of the loss can be estimated, then the estimated liability would be accrued in the company's financial statements. If the assessment indicates that a potentially material liability is not probable, but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss if determinable and material, would be disclosed.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the nature of the guarantee would be disclosed. However, in some instances in which disclosure is not otherwise required, the company may disclose contingent liabilities of an unusual nature which, in the judgment of management and its legal counsel, may be of interest to stockholders or others.

STATEMENT OF CONSOLIDATED CASH FLOWS

We present cash flows from operating activities using the indirect method. We exclude exploratory expenses from cash flows of operating activities and apply them to cash flows of investing activities. On this basis, we reflect all capital and exploratory expenditures as investing activities.

Statement of Consolidated Income

(Millions of dollars) For the years ended December 31	**1999**	1998	1997
Revenues			
Sales and services (includes transactions with significant affiliates of $4,839 million in 1999, $4,169 million in 1998 and $3,633 million in 1997)	**$ 34,975**	$ 30,910	$ 45,187
Equity in income of affiliates, interest, asset sales and other	**716**	797	1,480
Total revenues	**35,691**	31,707	46,667
Deductions			
Purchases and other costs (includes transactions with significant affiliates of $1,691 million in 1999, $1,669 million in 1998 and $2,178 million in 1997)	**27,442**	24,179	35,230
Operating expenses	**2,319**	2,508	3,251
Selling, general and administrative expenses	**1,186**	1,224	1,755
Exploratory expenses	**501**	461	471
Depreciation, depletion and amortization	**1,543**	1,675	1,633
Interest expense	**504**	480	412
Taxes other than income taxes	**334**	423	520
Minority interest	**83**	56	68
	33,912	31,006	43,340
Income before income taxes and cumulative effect of accounting change	**1,779**	701	3,327
Provision for income taxes	**602**	98	663
Income before cumulative effect of accounting change	**1,177**	603	2,664
Cumulative effect of accounting change	**—**	(25)	—
Net income	**$ 1,177**	$ 578	$ 2,664
Net Income per Common Share *(dollars)*			
Basic:			
Income before cumulative effect of accounting change	**$ 2.14**	$ 1.04	$ 4.99
Cumulative effect of accounting change	**—**	(.05)	—
Net income	**$ 2.14**	$ .99	$ 4.99
Diluted:			
Income before cumulative effect of accounting change	**$ 2.14**	$ 1.04	$ 4.87
Cumulative effect of accounting change	**—**	(.05)	—
Net income	**$ 2.14**	$ .99	$ 4.87
Average Number of Common Shares Outstanding (for computation of earnings per share) *(thousands)*			
Basic	**535,369**	528,416	522,234
Diluted	**537,860**	528,965	542,570

See accompanying notes to consolidated financial statements.

Consolidated Balance Sheet

(Millions of dollars) As of December 31	**1999**	1998
Assets		
Current Assets		
Cash and cash equivalents	**$ 419**	$ 249
Short-term investments – at fair value	**29**	22
Accounts and notes receivable (includes receivables from significant affiliates of $585 million in 1999 and $694 million in 1998), less allowance for doubtful accounts of $27 million in 1999 and $28 million in 1998	**4,060**	3,955
Inventories	**1,182**	1,154
Deferred income taxes and other current assets	**273**	256
Total current assets	**5,963**	5,636
Investments and Advances	**6,426**	7,184
Net Properties, Plant and Equipment	**15,560**	14,761
Deferred Charges	**1,023**	989
Total	**$ 28,972**	$ 28,570
Liabilities and Stockholders' Equity		
Current Liabilities		
Notes payable, commercial paper and current portion of long-term debt	**$ 1,041**	$ 939
Accounts payable and accrued liabilities (includes payables to significant affiliates of $61 million in 1999 and $395 million in 1998)		
Trade liabilities	**2,585**	2,302
Accrued liabilities	**1,203**	1,368
Estimated income and other taxes	**839**	655
Total current liabilities	**5,668**	5,264
Long-Term Debt and Capital Lease Obligations	**6,606**	6,352
Deferred Income Taxes	**1,468**	1,644
Employee Retirement Benefits	**1,184**	1,248
Deferred Credits and Other Non-current Liabilities	**1,294**	1,550
Minority Interest in Subsidiary Companies	**710**	679
Total	**16,930**	16,737
Stockholders' Equity		
Market auction preferred shares	**300**	300
ESOP convertible preferred stock	**—**	428
Unearned employee compensation and benefit plan trust	**(306)**	(334)
Common stock – shares issued: 567,576,504 in 1999; 567,606,290 in 1998	**1,774**	1,774
Paid-in capital in excess of par value	**1,287**	1,640
Retained earnings	**9,748**	9,561
Other accumulated non-owner changes in equity	**(119)**	(101)
	12,684	13,268
Less – Common stock held in treasury, at cost	**642**	1,435
Total stockholders' equity	**12,042**	11,833
Total	**$ 28,972**	$ 28,570

See accompanying notes to consolidated financial statements.

Statement of Consolidated Stockholders' Equity

(Shares in thousands; amounts in millions of dollars)	**Shares**	**Amount** **1999**	Shares	Amount 1998	Shares	Amount 1997
Preferred Stock						
par value $1; shares authorized – 30,000,000						
Market Auction Preferred Shares (Series G, H, I and J) –						
liquidation preference of $250,000 per share						
Beginning and end of year	**1**	**$ 300**	1	$ 300	1	$ 300
Series B ESOP Convertible Preferred Stock						
Beginning of year	**649**	**389**	693	416	720	432
Redemptions	**(587)**	**(352)**	—	—	—	—
Retirements	**(62)**	**(37)**	(44)	(27)	(27)	(16)
End of year	**—**	**—**	649	389	693	416
Series F ESOP Convertible Preferred Stock						
Beginning of year	**53**	**39**	56	41	57	42
Redemptions	**(53)**	**(39)**	—	—	—	—
Retirements	**—**	**—**	(3)	(2)	(1)	(1)
End of year	**—**	**—**	53	39	56	41
Unearned Employee Compensation						
(related to ESOP and restricted stock awards)						
Beginning of year		**(94)**		(149)		(175)
Awards		**(18)**		(36)		(16)
Amortization and other		**46**		91		42
End of year		**(66)**		(94)		(149)
Benefit Plan Trust						
(common stock)						
Beginning of year	**9,200**	**(240)**	9,200	(240)	8,000	(203)
Additions	**—**	**—**	—	—	1,200	(37)
End of year	**9,200**	**(240)**	9,200	(240)	9,200	(240)
Common Stock						
par value $3.125; shares authorized – 850,000,000						
Beginning of year	**567,606**	**1,774**	567,606	1,774	548,587	1,714
Monterey acquisition	**(29)**	**—**	—	—	19,019	60
End of year	**567,577**	**1,774**	567,606	1,774	567,606	1,774
Common Stock Held in Treasury, at Cost						
Beginning of year	**32,976**	**(1,435)**	25,467	(956)	21,191	(628)
Redemption of Series B and Series F ESOP Convertible Preferred Stock	**(16,180)**	**699**	—	—	—	—
Purchases of common stock	**—**	**—**	9,572	(551)	7,423	(410)
Transfer to benefit plan trust	**—**	**—**	—	—	(1,200)	37
Other – mainly employee benefit plans	**(2,327)**	**94**	(2,063)	72	(1,947)	45
End of year	**14,469**	**$ (642)**	32,976	$ (1,435)	25,467	$ (956)

See accompanying notes to consolidated financial statements.

(Continued on next page.)

Statement of Consolidated Stockholders' Equity

(Millions of dollars)	**1999**	1998	1997
Paid-in Capital in Excess of Par Value			
Beginning of year	**$ 1,640**	$ 1,688	$ 630
Redemption of Series B and Series F ESOP Convertible Preferred Stock	**(308)**	—	—
Monterey acquisition	**(2)**	—	1,091
Treasury stock transactions relating to investor services plan and employee compensation plans	**(43)**	(48)	(33)
End of year	**1,287**	1,640	1,688
Retained Earnings			
Balance at beginning of year	**9,561**	9,987	8,292
Add:			
Net income	**1,177**	578	2,664
Tax benefit associated with dividends on unallocated ESOP Convertible Preferred Stock and Common Stock	**2**	3	4
Deduct: Dividends declared on			
Common stock			
($1.80 per share in 1999 and 1998 and $1.75 per share in 1997)	**964**	952	918
Preferred stock			
Series B ESOP Convertible Preferred Stock	**17**	38	40
Series F ESOP Convertible Preferred Stock	**2**	4	4
Market Auction Preferred Shares (Series G, H, I and J)	**9**	13	11
Balance at end of year	**9,748**	9,561	9,987
Other Accumulated Non-owner Changes in Equity			
Currency translation adjustment			
Beginning of year	**(107)**	(105)	(65)
Change during year	**8**	(2)	(40)
End of year	**(99)**	(107)	(105)
Minimum pension liability adjustment			
Beginning of year	**(24)**	(16)	—
Change during year	**1**	(8)	(16)
End of year	**(23)**	(24)	(16)
Unrealized net gain on investments			
Beginning of year	**30**	26	33
Change during year	**(27)**	4	(7)
End of year	**3**	30	26
Total other accumulated non-owner changes in equity	**(119)**	(101)	(95)
Stockholders' Equity			
End of year (including preceding page)	**$ 12,042**	$ 11,833	$ 12,766

See accompanying notes to consolidated financial statements.

Statement of Consolidated Non-owner Changes in Equity

(Millions of dollars)	**1999**	1998	1997
Net Income	**$ 1,177**	$ 578	$ 2,664
Other Non-owner Changes in Equity:			
Currency translation adjustment			
Reclassification to net income of realized loss on sale of affiliate	**17**	—	—
Other unrealized net change during period	**(9)**	(2)	(40)
Total	**8**	(2)	(40)
Minimum pension liability adjustment			
Before income taxes	**1**	(16)	(21)
Income taxes	**—**	8	5
Total	**1**	(8)	(16)
Unrealized net gain on investments			
Net gain (loss) arising during period			
Before income taxes	**12**	35	22
Income taxes	**(2)**	(11)	(9)
Reclassification to net income of net realized (gain) or loss			
Before income taxes	**(48)**	(31)	(29)
Income taxes	**11**	11	9
Total	**(27)**	4	(7)
Total other non-owner changes in equity	**(18)**	(6)	(63)
Total non-owner changes in equity	**$ 1,159**	$ 572	$ 2,601

See accompanying notes to consolidated financial statements.

Statement of Consolidated Cash Flows

(Millions of dollars) For the years ended December 31	**1999**	1998	1997
Operating Activities			
Net income	**$ 1,177**	$ 578	$ 2,664
Reconciliation to net cash provided by (used in) operating activities			
Cumulative effect of accounting change	**—**	25	—
Depreciation, depletion and amortization	**1,543**	1,675	1,633
Deferred income taxes	**(140)**	(152)	451
Exploratory expenses	**501**	461	471
Minority interest in net income	**83**	56	68
Dividends from affiliates, greater than (less than) equity in income	**233**	224	(370)
Gains on asset sales	**(87)**	(109)	(558)
Changes in operating working capital			
Accounts and notes receivable	**(637)**	125	718
Inventories	**(28)**	(51)	(56)
Accounts payable and accrued liabilities	**382**	16	(856)
Other – mainly estimated income and other taxes	**130**	(205)	(64)
Other – net	**12**	(99)	(186)
Net cash provided by operating activities	**3,169**	2,544	3,915
Investing Activities			
Capital and exploratory expenditures	**(2,957)**	(3,101)	(3,628)
Proceeds from asset sales	**321**	282	1,036
Sales (purchases) of leasehold interests	**(23)**	25	(503)
Purchases of investment instruments	**(432)**	(947)	(1,102)
Sales/maturities of investment instruments	**778**	1,118	1,096
Collection of note/formation payments from U.S. affiliate	**101**	612	—
Other – net	**—**	—	(57)
Net cash used in investing activities	**(2,212)**	(2,011)	(3,158)
Financing Activities			
Borrowings having original terms in excess of three months			
Proceeds	**2,353**	1,300	507
Repayments	**(1,080)**	(741)	(637)
Net increase (decrease) in other borrowings	**(983)**	493	628
Purchases of common stock	**—**	(579)	(382)
Dividends paid to the company's stockholders			
Common	**(964)**	(952)	(918)
Preferred	**(28)**	(53)	(55)
Dividends paid to minority stockholders	**(55)**	(52)	(81)
Net cash used in financing activities	**(757)**	(584)	(938)
Cash and Cash Equivalents			
Effect of exchange rate changes	**(30)**	(11)	(19)
Increase (decrease) during year	**170**	(62)	(200)
Beginning of year	**249**	311	511
End of year	**$ 419**	$ 249	$ 311

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

NOTE 1 SEGMENT INFORMATION

We are presenting below information about our operating segments for the years 1999, 1998 and 1997, according to Statement of Financial Accounting Standards 131, "Disclosures about Segments of an Enterprise and Related Information," which we adopted in 1998. Due to the formation in 1999 of our Global Gas and Power segment, prior period information has been restated.

We determined our operating segments based on differences in the nature of their operations, geographic location and internal management reporting. The composition of segments and measure of segment profit are consistent with that used by our Executive Council in making strategic decisions. The Executive Council is headed by the Chairman and Chief Executive Officer and includes, among others, the Senior Vice Presidents having oversight responsibility for our business units.

Operating Segments 1999

	Sales and Services			After-tax Profit (Loss)	Income Tax Expense (Benefit)	DD&A Expense	Other Non-cash Items	Capital Expen-ditures	Assets at Year-End
(Millions of dollars)	Outside	Inter-segment	Total						
Exploration and production									
United States	$ 2,166	$ 1,547	$ 3,713	$ 652	$ 299	$ 758	$ 167	$ 670	$ 8,696
International	2,684	924	3,608	360	545	451	30	1,273	5,333
Refining, marketing and distribution									
United States	3,579	18	3,597	208	73	3	78	3	3,714
International	22,114	75	22,189	370	101	220	132	375	8,542
Global gas and power	4,422	117	4,539	(14)	(8)	65	10	161	1,297
Segment totals	$ 34,965	$ 2,681	37,646	1,576	1,010	1,497	417	2,482	27,582
Other business units			32	(3)	(2)	1	—	—	365
Corporate/Non-operating			6	(396)	(406)	45	(1)	21	1,430
Intersegment eliminations			(2,709)	—	—	—	—	—	(405)
Consolidated			$ 34,975	$ 1,177	$ 602	$ 1,543	$ 416	$ 2,503	$ 28,972

Operating Segments 1998

	Sales and Services			After-tax Profit (Loss)	Income Tax Expense (Benefit)	DD&A Expense	Other Non-cash Items	Capital Expen-ditures	Assets at Year-End
(Millions of dollars)	Outside	Inter-segment	Total						
Exploration and production									
United States	$ 1,712	$ 1,659	$ 3,371	$ 301	$ 34	$ 892	$ 1	$ 1,200	$ 8,699
International	2,020	695	2,715	129	132	513	18	901	4,345
Refining, marketing and distribution									
United States	2,612	29	2,641	221	88	29	230	1	4,066
International	19,805	106	19,911	332	130	204	135	396	8,214
Global gas and power	4,748	76	4,824	(16)	4	15	45	122	1,119
Segment totals	$ 30,897	$ 2,565	33,462	967	388	1,653	429	2,620	26,443
Other business units			50	(2)	—	1	3	—	381
Corporate/Non-operating			5	(362)	(290)	21	(67)	30	1,945
Intersegment eliminations			(2,607)	—	—	—	—	—	(199)
Consolidated, before cumulative effect of accounting change			$ 30,910	$ 603	$ 98	$ 1,675	$ 365	$ 2,650	$ 28,570

Operating Segments 1997

(Millions of dollars)	Sales and Services: Outside	Sales and Services: Inter-segment	Sales and Services: Total	After-tax Profit (Loss)	Income Tax Expense (Benefit)	DD&A Expense	Other Non-cash Items	Capital Expen-ditures	Assets at Year-End
Exploration and production									
United States	$ 365	$ 4,149	$ 4,514	$ 990	$ 487	$ 783	$ 281	$ 1,349	$ 8,769
International	2,565	693	3,258	812	566	442	104	901	4,107
Refining, marketing and distribution									
United States	16,984	250	17,234	325	172	178	169	262	5,668
International	20,009	362	20,371	508	117	173	(166)	482	7,908
Global gas and power	5,260	247	5,507	(46)	(6)	15	63	113	1,178
Segment totals	$ 45,183	$ 5,701	50,884	2,589	1,336	1,591	451	3,107	27,630
Other business units			64	2	2	1	3	—	431
Corporate/Non-operating			4	73	(675)	41	242	52	2,030
Intersegment eliminations			(5,765)	—	—	—	—	—	(491)
Consolidated			$ 45,187	$ 2,664	$ 663	$ 1,633	$ 696	$ 3,159	$ 29,600

Our exploration and production segments explore for, find, develop and produce crude oil and natural gas. The United States segment in 1998 and 1997 included minor operations in Canada. Our refining, marketing and distribution segments process crude oil and other feedstocks into refined products and purchase, sell and transport crude oil and refined petroleum products. The global gas and power segment includes the U.S. natural gas operations, which purchases natural gas and natural gas products from our exploration and production operations and third parties for resale. It also operates natural gas processing plants and pipelines in the United States. Also included in this segment are our power generation, gasification, hydrocarbons-to-liquids and fuel cell technology operations. This segment sold its U.K. wholesale gas business in 1998 and its U.K. retail gas marketing business in 1999. Other business units include our insurance operations and investments in undeveloped mineral properties. None of these units is individually significant in terms of revenue, income or assets.

You are encouraged to read Note 5 — *Investments and Advances,* beginning on page 41, which includes information about our affiliates and the formation of the Equilon and Motiva alliances in 1998.

Corporate and non-operating includes the assets, income and expenses relating to cash management and financing activities, our corporate center and other items not directly attributable to the operating segments.

We apply the same accounting policies to each of the segments as we do in preparing the consolidated financial statements. Intersegment sales and services are generally representative of market prices or arms-length negotiated transactions. Intersegment receivables are representative of normal trade balances. Other non-cash items principally include deferred income taxes, the difference between cash distributions and equity in income of affiliates, and non-cash charges and credits associated with asset sales. Capital expenditures are presented on a cash basis, excluding exploratory expenses.

The countries in which we have significant sales and services and long-lived assets are listed below. Sales and services are based on the origin of the sale. Long-lived assets include properties, plant and equipment and investments in foreign producing operations where the host governments own the physical assets under terms of the operating agreements.

(Millions of dollars)	Sales and Services: **1999**	Sales and Services: 1998	Sales and Services: 1997	Long-lived assets at December 31: **1999**	Long-lived assets at December 31: 1998	Long-lived assets at December 31: 1997
United States	**$ 9,733**	$ 8,184	$ 21,657	**$ 8,630**	$ 8,757	$ 11,437
International – Total	**$ 25,242**	$ 22,726	$ 23,530	**$ 7,109**	$ 6,250	$ 5,876
Significant countries included above:						
Brazil	**2,404**	3,175	3,175	**326**	301	266
Netherlands	**1,955**	1,636	1,901	**246**	257	250
United Kingdom	**9,211**	7,529	6,862	**2,275**	2,257	2,384

NOTE 2 ADOPTION OF NEW ACCOUNTING STANDARDS

SFAS 128 — During 1997, we adopted SFAS 128, "Earnings per Share." Our basic and diluted net income per common share under SFAS 128 were approximately the same as under the comparable prior basis of reporting.

SFAS 130, 131 and 132 — In 1998, Texaco adopted SFAS 130, 131 and 132. SFAS 130, "Reporting Comprehensive Income," requires that we report all items classified as comprehensive income under its provisions as separate components within a financial statement. SFAS 131, "Disclosures about Segments of an Enterprise and Related Information," requires the reporting of certain income, revenue, expense and asset data about operating segments of public enterprises. Operating segments are based upon a company's internal management structure. SFAS 131 also requires data for revenues and long-lived assets by major countries of operation. SFAS 132, "Employer's Disclosures about Pensions and Other Postretirement Benefits," requires disclosure of new information on changes in plan benefit obligations and fair values of plan assets.

SOP 98-5 — Effective January 1, 1998, Caltex, our affiliate, adopted Statement of Position 98-5, "Reporting on the Costs of Start-Up Activities," issued by the American Institute of Certified Public Accountants. This Statement requires that the costs of start-up activities and organization costs, as defined, be expensed as incurred. The cumulative effect of adoption on Texaco's net income for 1998 was a net loss of $25 million. This Statement was adopted by Texaco and our other affiliates effective January 1, 1999. The effect was not significant.

NOTE 3 INCOME PER COMMON SHARE

Basic net income per common share is net income less preferred stock dividend requirements divided by the average number of common shares outstanding. Diluted net income per common share assumes issuance of the net incremental shares from stock options and full conversion of all dilutive convertible securities at the later of the beginning of the year or date of issuance. Common shares held by the benefit plan trust are not considered outstanding for purposes of net income per common share.

(Millions, except per share amounts)		**1999**			1998			1997	
For the years ended December 31	**Income**	**Shares**	**Per Share**	Income	Shares	Per Share	Income	Shares	Per Share
Basic net income:									
Income before cumulative effect of accounting change	**$ 1,177**			$ 603			$ 2,664		
Less: Preferred stock dividends	**(29)**			(54)			(56)		
Income before cumulative effect of accounting change, for basic income per share	**$ 1,148**	**535.4**	**$ 2.14**	$ 549	528.4	$ 1.04	$ 2,608	522.2	$ 4.99
Effect of dilutive securities:									
ESOP Convertible preferred stock	**—**	**—**		—	—		34	19.3	
Stock options and restricted stock	**3**	**2.5**		—	.4		—	.8	
Convertible debentures	**—**	**—**		1	.2		—	.3	
Income before cumulative effect of accounting change, for diluted income per share	**$ 1,151**	**537.9**	**$ 2.14**	$ 550	529.0	$ 1.04	$ 2,642	542.6	$ 4.87

NOTE 4 INVENTORIES

(Millions of dollars) *As of December 31*	**1999**	1998
Crude oil	**$ 141**	$ 116
Petroleum products and other	**857**	839
Materials and supplies	**184**	199
Total	**$ 1,182**	$ 1,154

At December 31, 1999, the excess of estimated market value over the carrying value of inventories was $136 million. The carrying value of inventories at December 31, 1998 is net of a valuation allowance of $99 million to adjust from cost to market value. This valuation allowance was reversed in 1999 as market prices increased and the associated physical units of inventory were sold.

NOTE 5 INVESTMENTS AND ADVANCES

We account for our investments in affiliates, including corporate joint ventures and partnerships owned 50% or less, on the equity method. Our total investments and advances are summarized as follows:

(Millions of dollars) *As of December 31*	**1999**	1998
Affiliates accounted for on the equity method		
Exploration and production		
United States	**$ 243**	$ 230
International		
CPI	**454**	452
Other	**14**	24
	711	706
Refining, marketing and distribution		
United States		
Equilon	**1,953**	2,266
Motiva	**686**	896
International		
Caltex	**1,685**	1,747
Other	**234**	210
	4,558	5,119
Global gas and power	**281**	188
Other affiliates	**13**	3
Total	**5,563**	6,016
Miscellaneous investments, long-term receivables, etc., accounted for at:		
Fair value	**138**	470
Cost, less reserve	**725**	698
Total	**$ 6,426**	$ 7,184

Our equity in the net income of affiliates is adjusted to reflect income taxes for limited liability companies and partnerships whose income is directly taxable to us:

(Millions of dollars) *For the years ended December 31*	**1999**	1998	1997
Equity in net income (loss)			
Exploration and production			
United States	**$ 53**	$ 37	$ 40
International			
CPI	**139**	107	171
Other	**—**	(12)	—
	192	132	211
Refining, marketing and distribution			
United States			
Equilon	**142**	199	—
Motiva	**(3)**	22	—
Star	**—**	(3)	95
Other	**—**	—	48
International			
Caltex	**11**	(36)	252
Other	**27**	15	20
	177	197	415
Global gas and power	**6**	(11)	(11)
Other affiliates	**—**	—	1
Total	**$ 375**	$ 318	$ 616
Dividends received	**$ 716**	$ 709	$ 332

The undistributed earnings of these affiliates included in our retained earnings were $2,613 million, $2,846 million and $3,096 million as of December 31, 1999, 1998 and 1997.

Caltex Group

We have investments in the Caltex Group of Companies, owned 50% by Texaco and 50% by Chevron Corporation. The Caltex group consists of P.T. Caltex Pacific Indonesia (CPI), American Overseas Petroleum Limited and subsidiary and Caltex Corporation and subsidiaries (Caltex). This group of companies is engaged in the exploration for and production, transportation, refining and marketing of crude oil and products in Africa, Asia, Australia, the Middle East and New Zealand.

Results for the Caltex Group in 1998 include an after-tax charge of $50 million (Texaco's share $25 million) for the cumulative effect of accounting change. See Note 2 for additional information.

Equilon Enterprises LLC

Effective January 1, 1998, Texaco and Shell Oil Company formed Equilon Enterprises LLC (Equilon), a Delaware limited liability company. Equilon is a joint venture that combined major elements of the companies' western and midwestern U.S. refining and marketing businesses and their nationwide trading, transportation and lubricants businesses. We own 44% and Shell Oil Company owns 56% of Equilon.

The carrying amounts at January 1, 1998, of the principal assets and liabilities of the businesses we contributed to Equilon were $.2 billion of net working capital assets, $2.8 billion of net properties, plant and equipment and $.2 billion of debt. These amounts were reclassified to investment in affiliates accounted for by the equity method.

In April 1998, we received $463 million from Equilon, representing reimbursement of certain capital expenditures incurred prior to the formation of the joint venture. In July 1998, we received $149 million from Equilon for certain specifically identified assets transferred for value to Equilon. In February 1999, we received $101 million from Equilon for the payment of notes receivable.

Motiva Enterprises LLC

Effective July 1, 1998, Texaco, Shell and Saudi Aramco formed Motiva Enterprises LLC (Motiva), a Delaware limited liability company. Motiva is a joint venture that combined Texaco's and Saudi Aramco's interests and major elements of Shell's eastern and Gulf Coast U.S. refining and marketing businesses. Texaco's and Saudi Aramco's interest in these businesses were previously conducted by Star Enterprise (Star), a joint-venture partnership owned 50% by Texaco and 50% by Saudi Refining, Inc., a corporate affiliate of Saudi Aramco. Texaco and Saudi Refining, Inc., each owns 32.5% and Shell owns 35% of Motiva.

The investment in Motiva at date of formation approximated the previous investment in Star. The Motiva investment and previous Star investment are recorded as investment in affiliates accounted for on the equity method.

The following table provides summarized financial information on a 100% basis for the Caltex Group, Equilon, Motiva, Star and all other affiliates that we account for on the equity method, as well as Texaco's total share of the information. The net income of all limited liability companies and partnerships is net of estimated income taxes. The actual income tax liability is reflected in the accounts of the respective members or partners and is not shown in the following table.

Motiva's and Star's assets at the respective balance sheet dates include the remaining portion of the assets which were originally transferred from Texaco to Star at the fair market value on the date of formation of Star. Our investment and equity in the income of Motiva and Star, as reported in our consolidated financial statements, reflect the remaining unamortized historical carrying cost of the assets transferred to Star at formation of Star. Additionally, our investments in Motiva and Star include adjustments for contractual arrangements on the formation of Star, principally involving contributed inventories.

(Millions of dollars)	**Equilon**	**Motiva**	**Caltex Group**	**Other Affiliates**	**Total Texaco's Share**
1999					
Gross revenues	**$ 29,398**	**$ 12,196**	**$ 14,915**	**$ 2,895**	**$ 25,650**
Income (loss) before income taxes	**$ 347**	**$ (69)**	**$ 780**	**$ 348**	**$ 679**
Net income (loss)	**$ 226**	**$ (45)**	**$ 390**	**$ 232**	**$ 375**
As of December 31:					
Current assets	**$ 4,209**	**$ 1,271**	**$ 2,705**	**$ 801**	**$ 3,796**
Non-current assets	**7,208**	**5,307**	**7,604**	**2,230**	**9,321**
Current liabilities	**(5,636)**	**(1,278)**	**(3,395)**	**(736)**	**(4,916)**
Non-current liabilities	**(735)**	**(2,095)**	**(2,639)**	**(792)**	**(2,638)**
Net equity	**$ 5,046**	**$ 3,205**	**$ 4,275**	**$ 1,503**	**$ 5,563**

(Millions of dollars)	Equilon	Motiva	Star	Caltex Group	Other Affiliates	Total Texaco's Share
1998						
Gross revenues	$ 22,246	$ 5,371	$ 3,190	$ 11,505	$ 2,541	$ 20,021
Income (loss) before income taxes and cumulative effect of accounting change	$ 502	$ 78	$ (128)	$ 519	$ 170	$ 662
Net income (loss)	$ 326	$ 51	$ (83)	$ 143	$ 84	$ 318
As of December 31:						
Current assets	$ 2,640	$ 1,481		$ 1,974	$ 687	$ 2,769
Non-current assets	7,752	5,257		7,684	2,021	9,313
Current liabilities	(4,044)	(1,243)		(2,839)	(727)	(3,924)
Non-current liabilities	(382)	(1,667)		(2,421)	(672)	(2,142)
Net equity	$ 5,966	$ 3,828		$ 4,398	$ 1,309	$ 6,016

(Millions of dollars)	Star	Caltex Group	Other Affiliates	Total Texaco's Share
1997				
Gross revenues	$ 7,758	$ 15,699	$ 4,028	$ 13,312
Income before income taxes	$ 301	$ 1,210	$ 605	$ 940
Net income	$ 196	$ 846	$ 400	$ 616
As of December 31:				
Current assets	$ 1,042	$ 2,521	$ 947	$ 1,965
Non-current assets	3,260	7,193	3,607	6,324
Current liabilities	(769)	(2,991)	(1,032)	(2,270)
Non-current liabilities	(1,072)	(2,131)	(2,022)	(2,198)
Net equity	$ 2,461	$ 4,592	$ 1,500	$ 3,821

NOTE 6 PROPERTIES, PLANT AND EQUIPMENT

	Gross		Net	
(Millions of dollars) As of December 31	**1999**	1998	**1999**	1998
Exploration and production				
United States	**$ 21,565**	$ 21,991	**$ 7,822**	$ 7,945
International	**8,835**	7,554	**3,804**	2,950
Total	**30,400**	29,545	**11,626**	10,895
Refining, marketing and distribution				
United States	**33**	75	**22**	27
International	**4,575**	4,487	**3,107**	3,055
Total	**4,608**	4,562	**3,129**	3,082
Global gas and power	**748**	660	**317**	267
Other	**771**	727	**488**	517
Total	**$ 36,527**	$ 35,494	**$ 15,560**	$ 14,761
Capital lease amounts included above	**$ 152**	$ 264	**$ 3**	$ 79

Accumulated depreciation, depletion and amortization totaled $20,967 million and $20,733 million at December 31, 1999 and 1998. Interest capitalized as part of properties, plant and equipment was $28 million in 1999, $21 million in 1998 and $20 million in 1997.

In 1999, 1998 and 1997, we recorded pre-tax charges of $87 million, $150 million and $63 million for the write-downs of impaired assets. These charges were recorded to depreciation, depletion and amortization expense.

1999

In our global gas and power operating segment, pre-tax asset write-downs from the impairment of certain gas plants in Louisiana were $49 million. We determined in the fourth quarter that, as a result of declining gas volumes available for processing, the carrying value of these plants exceeded future undiscounted cash flows. Fair value was determined by discounting expected future cash flows.

Pre-tax asset write-downs of $28 million included in corporate resulted from our joint plan with state and local agencies to convert for third-party industrial use idle facilities, formerly used in research activities. The facilities and equipment were written down to their appraised values. An additional $10 million was recorded to bring certain marketing assets of our subsidiary in Poland to be disposed of to their appraised value.

1998

In the U.S. exploration and production operating segment, pre-tax asset write-downs for impaired properties in Louisiana and Canada were $64 million. The Louisiana property represents an unsuccessful enhanced recovery project. We determined in the fourth quarter of 1998 that the carrying value of this property exceeded future undiscounted cash flows. Fair value was determined by discounting expected future cash flows. Canadian properties were impaired following our decision in October 1998 to exit the upstream business in Canada. These properties were written down to their sales price with the sale closing in December 1998.

In the international exploration and production operating segment, the pre-tax asset write-down for the impairment of our investment in the Strathspey field in the U.K. North Sea was $58 million. The Strathspey impairment was caused by a downward revision in the fourth quarter of the estimated volume of the field's proved reserves. Fair value was determined by discounting expected future cash flows.

In the U.S. downstream operating segment, the pre-tax asset write-downs for the impairment of surplus facilities and equipment held for sale and not transferred to the Equilon joint venture was $28 million. Fair value was determined by an independent appraisal.

1997

In our U.S. exploration and producing operating segment, pre-tax asset write-downs for impaired properties in Louisiana and Canada were $48 million. The Louisiana impairment resulted from the write-downs of gas plants due to insufficient contract volumes and the Canadian impairment resulted from unsuccessful enhanced recovery projects and downward revisions to underground reserves.

In our international exploration and producing operating segment, pre-tax asset write-downs of $15 million for impaired properties in the U.K. North Sea were caused by downward revisions to underground reserves.

Fair values were based on expected future discounted cash flows.

NOTE 7 FOREIGN CURRENCY

Currency translations resulted in pre-tax losses of $47 million in 1999, $80 million in 1998 and $59 million in 1997. After applicable taxes, 1999 included a gain of $25 million compared to a loss of $94 million in 1998 and a gain of $154 million in 1997.

The after-tax currency gain in 1999 related principally to balance sheet translation. After-tax currency impacts for years 1998 and 1997 were largely due to currency volatility in Asia. In 1998, our Caltex affiliate incurred significant currency-related losses due to the strengthening of the Korean won and Japanese yen against the U.S. dollar. In contrast, those currencies weakened against the U.S. dollar in 1997, which resulted in significant currency-related gains.

Results for 1997 through 1999 were also impacted by the effect of currency rate changes on deferred income taxes denominated in British pounds. This results in gains from strengthening of the U.S. dollar and losses from weakening of the U.S. dollar. These effects were gains of $8 million in 1999, losses of $5 million in 1998 and gains of $28 million in 1997.

Effective October 1, 1997, Caltex changed the functional currency for its operations in its Korean and Japanese affiliates to the U.S. dollar.

Currency translation adjustments shown in the separate stockholders' equity account result from translation items pertaining to certain affiliates of Caltex. For 1999, we recorded unrealized losses of $9 million from these adjustments. In addition, we reversed an existing $17 million deferred loss due to the sale by Caltex of its investment in Koa Oil Company, Limited. As a result, a $17 million loss was recorded in Texaco's net income as part of the loss on this sale. For years 1998 and 1997, currency translation losses recorded to stockholders' equity were $2 million and $40 million.

NOTE 8 TAXES

(Millions of dollars)	**1999**	1998	1997
Federal and other income taxes			
Current			
U.S. Federal	**$ 100**	$ (45)	$ (538)
Foreign	**678**	283	689
State and local	**(36)**	12	61
Total	**742**	250	212
Deferred			
U.S.	**(120)**	(104)	457
Foreign	**(20)**	(48)	(6)
Total	**(140)**	(152)	451
Total income taxes	**602**	98	663
Taxes other than income taxes			
Oil and gas production	**64**	70	127
Property	**69**	108	139
Payroll	**91**	119	125
Other	**110**	126	129
Total	**334**	423	520
Import duties and other levies			
U.S.	**34**	36	53
Foreign	**6,937**	6,843	5,414
Total	**6,971**	6,879	5,467
Total direct taxes	**7,907**	7,400	6,650
Taxes collected from consumers	**2,097**	2,148	3,370
Total all taxes	**$ 10,004**	$ 9,548	$ 10,020

The deferred income tax assets and liabilities included in the Consolidated Balance Sheet as of December 31, 1999 and 1998 amounted to $198 million and $205 million, as net current assets and $1,468 million and $1,644 million, as net non-current liabilities. The table that follows shows deferred income tax assets and liabilities by category:

	(Liability) Asset	
(Millions of dollars) As of December 31	**1999**	1998
Depreciation	**$ (991)**	$ (1,079)
Depletion	**(383)**	(429)
Intangible drilling costs	**(881)**	(726)
Other deferred tax liabilities	**(691)**	(686)
Total	**(2,946)**	(2,920)
Employee benefit plans	**548**	532
Tax loss carryforwards	**599**	641
Tax credit carryforwards	**495**	368
Environmental liabilities	**123**	116
Other deferred tax assets	**711**	639
Total	**2,476**	2,296
Total before valuation allowance	**(470)**	(624)
Valuation allowance	**(800)**	(815)
Total	**$ (1,270)**	$ (1,439)

The preceding table excludes certain potential deferred income tax asset amounts for which possibility of realization is extremely remote.

The valuation allowance relates principally to upstream operations in Denmark. The related deferred income tax assets result from tax loss carryforwards and book versus tax asset basis differences for a hydrocarbon tax. Loss carryforwards from this tax are generally determined by individual field and, in that case, are not usable against other fields' taxable income.

The following schedule reconciles the differences between the U.S. Federal income tax rate and the effective income tax rate excluding the cumulative effect of accounting change in 1998:

	1999	1998	1997
U.S. Federal income tax rate assumed to be applicable	**35.0%**	35.0%	35.0%
IRS settlement	**—**	—	(14.7)
Net earnings and dividends attributable to affiliated corporations accounted for on the equity method	**(3.8)**	(7.0)	(4.7)
Aggregate earnings and losses from international operations	**14.4**	10.4	6.2
U.S. tax adjustments	**(5.0)**	(8.7)	(.3)
Sales of stock of subsidiaries	**(2.2)**	(6.1)	—
Energy credits	**(3.8)**	(11.7)	(1.4)
Other	**(.8)**	2.1	(.2)
Effective income tax rate	**33.8%**	14.0%	19.9%

The year 1997 included a $488 million benefit resulting from an IRS settlement.

For companies operating in the United States, pre-tax earnings before the cumulative effect of an accounting change aggregated $484 million in 1999, $194 million in 1998 and $1,527 million in 1997. For companies with operations located outside the United States, pre-tax earnings on that basis aggregated $1,295 million in 1999, $507 million in 1998 and $1,800 million in 1997.

Income taxes paid, net of refunds, amounted to $600 million, $430 million and $285 million in 1999, 1998 and 1997.

The undistributed earnings of subsidiary companies and of affiliated corporate joint-venture companies accounted for on the equity method, for which deferred U.S. income taxes have not been provided at December 31, 1999, amounted to $1,708 million and $2,187 million. The corresponding amounts at December 31, 1998 were $1,328 million and $2,226 million. Determination of the unrecognized U.S. deferred income taxes on these amounts is not practicable.

For the years 1999, 1998 and 1997, no loss carryforward benefits were recorded for U.S. Federal income taxes. For the years 1999, 1998 and 1997, the tax benefits recorded for loss carryforwards were $54 million, $30 million and $31 million in foreign income taxes.

At December 31, 1999, we had worldwide tax basis loss carryforwards of approximately $1,647 million, including $941 million which do not have an expiration date. The remainder expire at various dates through 2019.

Foreign tax credit carryforwards available for U.S. Federal income tax purposes amounted to approximately $245 million at December 31, 1999, expiring at various dates through 2004. Alternative minimum tax and other tax credit carryforwards available for U.S. Federal income tax purposes were $461 million at December 31, 1999, of which $357 million have no expiration date. The remaining credits expire at various dates through 2014. The credits that are not utilized by the expiration dates may be taken as deductions for U.S. Federal income tax purposes. For the year 1999, we recorded tax credit carryforwards of $68 million for U.S. Federal income tax purposes.

NOTE 9 SHORT-TERM DEBT, LONG-TERM DEBT, CAPITAL LEASE OBLIGATIONS AND RELATED DERIVATIVES

Notes Payable, Commercial Paper and Current Portion of Long-term Debt

(Millions of dollars) As of December 31	**1999**	1998
Notes payable to banks and others with originating terms of one year or less	**$ 1,251**	$ 368
Commercial paper	**1,099**	1,617
Current portion of long-term debt and capital lease obligations		
Indebtedness	**734**	991
Capital lease obligations	**7**	13
	3,091	2,989
Less short-term obligations intended to be refinanced	**2,050**	2,050
Total	**$ 1,041**	$ 939

The weighted average interest rate of commercial paper and notes payable to banks at December 31, 1999 and 1998 was 5.9%.

Long-term Debt and Capital Lease Obligations

(Millions of dollars) As of December 31	**1999**	1998
Long-Term Debt		
3-1/2% convertible notes due 2004	**$ 203**	$ 204
5.5% note due 2009	**397**	—
5.7% notes due 2008	**201**	201
6% notes due 2005	**299**	299
6-7/8% notes due 1999	**—**	200
6-7/8% debentures due 2023	**196**	196
7.09% notes due 2007	**150**	150
7-1/2% debentures due 2043	**198**	198
7-3/4% debentures due 2033	**199**	199
8% debentures due 2032	**148**	147
8-1/4% debentures due 2006	**150**	150
8-3/8% debentures due 2022	**198**	198
8-1/2% notes due 2003	**200**	199
8-5/8% debentures due 2010	**150**	150
8-5/8% debentures due 2031	**199**	199
8-5/8% debentures due 2032	**199**	199
8-7/8% debentures due 2021	**150**	150
9% notes due 1999	**—**	200
9-3/4% debentures due 2020	**250**	250
Medium-term notes, maturing from 2000 to 2043 (7.0%)	**757**	543
Revolving Credit Facility, due 1999-2002 – variable rate (5.9%)	**—**	309
Pollution Control Revenue Bonds, due 2012 – variable rate (3.5%)	**166**	166
Other long-term debt:		
Texaco Inc. – Guarantee of ESOP Series F loan – variable rate (6.6%)	**—**	2
U.S. dollars (6.6%)	**369**	335
Other currencies (9.4%)	**472**	394
Total	**5,251**	5,238
Capital Lease Obligations (see Note 10)	**46**	68
	5,297	5,306
Less current portion of long-term debt and capital lease obligations	**741**	1,004
	4,556	4,302
Short-term obligations intended to be refinanced	**2,050**	2,050
Total long-term debt and capital lease obligations	**$ 6,606**	$ 6,352

The percentages shown for variable-rate debt are the interest rates at December 31, 1999. The percentages shown for the categories "Medium-term notes" and "Other long-term debt" are the weighted average interest rates at year-end 1999. Where applicable, principal amounts shown in the preceding schedule include unamortized premium or discount. Interest paid, net of amounts capitalized, amounted to $480 million in 1999, $474 million in 1998 and $395 million in 1997.

At December 31, 1999, we had revolving credit facilities with commitments of $2.05 billion with syndicates of major U.S. and international banks. These facilities are available as support for our issuance of commercial paper as well as for working capital and other general corporate purposes. We had no amounts outstanding under these facilities at year-end 1999. We pay commitment fees on these facilities. The banks reserve the right to terminate the credit facilities upon the occurrence of certain specific events, including a change in control.

At December 31, 1999, our long-term debt included $2.05 billion of short-term obligations scheduled to mature during 2000, which we have both the intent and the ability to refinance on a long-term basis through the use of our $2.05 billion revolving credit facilities.

Contractual annual maturities of long-term debt, including sinking fund payments and potential repayments resulting from options that debtholders might exercise, for the five years subsequent to December 31, 1999 are as follows (in millions):

2000	2001	2002	2003	2004
$ 734	$ 135	$ 191	$ 273	$ 31

Debt-related Derivatives

We seek to maintain a balanced capital structure that provides financial flexibility and supports our strategic objectives while achieving a low cost of capital. This is achieved by balancing our liquidity and interest rate exposures. We manage these exposures primarily through long-term and short-term debt on the balance sheet. In managing our exposure to interest rates, we seek to balance the benefit of the lower cost of floating rate debt, with its inherent increased risk, with fixed rate debt having less market risk. To achieve this objective, we also use off-balance sheet derivative instruments, primarily interest rate swaps, to manage identifiable exposures on a non-leveraged, non-speculative basis.

Summarized below are the carrying amounts and fair values of our debt and debt-related derivatives at December 31, 1999 and 1998. Our use of derivatives during the periods presented was limited to interest rate swaps, where we either paid or received the net effect of a fixed rate versus a floating rate (commercial paper or LIBOR) index at specified intervals, calculated by reference to an agreed notional principal amount.

(Millions of dollars) As of December 31	**1999**	1998
Notes Payable and Commercial Paper:		
Carrying amount	**$ 2,350**	$ 1,985
Fair value	**2,348**	1,985
Related Derivatives – Payable (Receivable):		
Carrying amount	**$ —**	$ —
Fair value	**(13)**	17
Notional principal amount	**$ 300**	$ 300
Weighted average maturity *(years)*	**7.3**	8.3
Weighted average fixed pay rate	**6.42%**	6.42%
Weighted average floating receive rate	**6.42%**	5.32%
Long-Term Debt, including current maturities:		
Carrying amount	**$ 5,251**	$ 5,238
Fair value	**5,225**	5,842
Related Derivatives – Payable (Receivable):		
Carrying amount	**$ (19)**	$ (4)
Fair value	**55**	(9)
Notional principal amount	**$ 1,294**	$ 449
Weighted average maturity *(years)*	**5.8**	8.4
Weighted average fixed receive rate	**5.69%**	6.24%
Weighted average floating pay rate	**6.10%**	5.03%
Unamortized net gain on terminated swaps		
Carrying amount	**$ 4**	$ 5

Excluded from this table is an interest rate and equity swap with a notional principal amount of $200 million entered into in 1997, related to the 3-1/2% notes due 2004. We pay a floating rate and receive a fixed rate. Also, the counterparty assumes all exposure for the potential equity-based cash redemption premium on the notes. The fair value of this swap was not significant at year-end 1999 and 1998.

During 1999, floating rate pay swaps having an aggregate notional principal amount of $30 million were amortized or matured. We initiated $875 million of new floating rate pay swaps in connection with certain of the 1999 debt issuances. There was no activity in fixed rate pay swaps during 1999.

Fair values of debt are based upon quoted market prices, as well as rates currently available to us for borrowings with similar terms and maturities. We estimate the fair value of swaps as the amount that would be received or paid to terminate the agreements at year-end, taking into account current interest rates and the current creditworthiness of the swap counterparties. The notional amounts of derivative contracts do not represent cash flow and are not subject to credit risk.

Amounts receivable or payable based on the interest rate differentials of derivatives are accrued monthly and are reflected in interest expense as a hedge of interest on outstanding debt. Gains and losses on terminated swaps are deferred and amortized over the life of the associated debt or the original term of the swap, whichever is shorter.

NOTE 10 LEASE COMMITMENTS AND RENTAL EXPENSE

We have leasing arrangements involving service stations, tanker charters, crude oil production and processing equipment and other facilities. We reflect amounts due under capital leases in our balance sheet as obligations, while we reflect our interest in the related assets as properties, plant and equipment. The remaining lease commitments are operating leases, and we record payments on such leases as rental expense.

As of December 31, 1999, we had estimated minimum commitments for payment of rentals (net of non-cancelable sublease rentals) under leases which, at inception, had a non-cancelable term of more than one year, as follows:

(Millions of dollars)	Operating Leases	Capital Leases
2000	$ 134	$ 9
2001	93	9
2002	416	8
2003	50	7
2004	54	7
After 2004	315	14
Total lease commitments	$ 1,062	$ 54
Less interest		8
Present value of total capital lease obligations		$ 46

Operating lease commitments for 2002 include a $304 million residual value guarantee of leased production facilities if we do not renew the lease.

Rental expense relative to operating leases, including contingent rentals based on factors such as gallons sold, is provided in the table below. Such payments do not include rentals on leases covering oil and gas mineral rights.

(Millions of dollars)	**1999**	1998	1997
Rental expense			
Minimum lease rentals	**$ 218**	$ 208	$ 270
Contingent rentals	**6**	—	3
Total	**224**	208	273
Less rental income on properties subleased to others	**54**	50	78
Net rental expense	**$ 170**	$ 158	$ 195

NOTE 11 EMPLOYEE BENEFIT PLANS

Texaco Inc. and certain of its non-U.S. subsidiaries sponsor various benefit plans for active employees and retirees. The costs of the savings, health care and life insurance plans relative to employees' active service are shared by the company and its employees, with Texaco's costs for these plans charged to expense as incurred. In addition, accruals for employee benefit plans are provided principally for the unfunded costs of various pension plans, retiree health and life insurance benefits, incentive compensation plans and for separation benefits payable to employees.

Employee Stock Ownership Plans (ESOP)

We recorded ESOP expense of $3 million in 1999, $1 million in 1998 and $2 million in 1997. Our contributions to the Employees Thrift Plan of Texaco Inc. and the Employees Savings Plan of Texaco Inc. amounted to $3 million in 1999, $1 million in 1998 and $2 million in 1997. These plans are designed to provide participants with a benefit of approximately 6% of base pay, as well as any benefits earned under the current employee Performance Compensation Program. In December 1999, we made a $27 million advanced company ESOP allocation for the period December 1999 through November 2000 to participants of the Employees Thrift Plan.

During the year, we called the Series B and Series F Convertible Preferred Stock and converted them into Texaco common stock, with future ESOP allocations being made in common stock. Following this conversion, we paid $12 million in dividends. Dividends on the preferred and common ESOP shares used to service debt of the plans are tax deductible to the company.

In 1999, 1998 and 1997, we paid $19 million, $42 million and $44 million in dividends on Series B and Series F stock. The trustee applied the dividends to fund interest payments which amounted to $2 million, $5 million and $7 million for 1999, 1998 and 1997, as well as to reduce principal on the ESOP loans. The Savings Plan ESOP loan was satisfied in January 1999. In November 1998 and December 1997, a portion of the original Thrift Plan ESOP loan was refinanced through a company loan. The refinancing will extend the ESOP for a period of up to six years.

We include in our long-term debt the plans' original ESOP loans guaranteed by Texaco Inc. As the ESOP repays the original and refinanced ESOP loans, we reduce the remaining ESOP-related unearned employee compensation included as a component of stockholders' equity.

Benefit Plan Trust

We have established a benefit plan trust for funding company obligations under some of our benefit plans. At year-end 1999, the trust contained 9.2 million shares of treasury stock. We intend to continue to pay our obligations under our benefit plans. The trust will use the shares, proceeds from the sale of such shares and dividends on such shares to pay benefits only to the extent that we do not pay such benefits. The trustee will vote the shares held in the trust as instructed by the trust's beneficiaries. The shares held by the trust are not considered outstanding for earnings per share purposes until distributed or sold by the trust in payment of benefit obligations.

Termination Benefits

In the fourth quarter of 1998, we announced we were restructuring several of our operations. The principal units affected were our worldwide upstream; our international downstream, principally our marketing operations in the United Kingdom and Brazil and our refining operations in Panama; our global gas marketing operations, now included as part of our global gas and power segment; and our corporate center. In 1998, we recorded an after-tax charge of $80 million for employee separations, curtailment costs and special termination benefits associated with our restructuring. The charge was comprised of $88 million of operating expenses, $27 million of selling, general and administrative expenses and $35 million in related income tax benefits. We initially estimated that over 1,400 employee reductions worldwide would occur. In the second quarter of 1999, we expanded the employee separation programs and recorded an after-tax charge of $31 million to cover an additional 1,100 employee reductions. The charge was comprised of $36 million of operating expenses, $12 million of selling, general and administrative expenses and $17 million in related income tax benefits. The restructuring programs were completed during 1999. Through December 31, 1999, under these programs we have separated 2,462 employees and paid $124 million of benefits and transferred $12 million to long-term obligations. The remaining benefits of $27 million will be paid in future periods in accordance with plan provisions.

We recorded an after-tax charge of $56 million in the fourth quarter of 1996 to cover the costs of employee separations, including employees of affiliates, as a result of a company-wide realignment and consolidation of our operations. We recorded an adjustment of $6 million in the fourth quarter of 1997 to increase the accrual from the previous amount. The program was completed by the end of 1997 with the reduction of approximately 920 employees. During 1999 we paid $4 million of benefits under this program. The remaining benefits of $8 million will be paid in future periods in accordance with plan provisions.

Pension Plans

We sponsor pension plans that cover the majority of our employees. Generally, these plans provide defined pension benefits based on years of service and final average pay. Pension plan assets are principally invested in equity and fixed income securities and deposits with insurance companies.

Effective October 1, 1999, the Retirement Plan was changed to provide improved early retirement benefits and/or lump sum options availability, for vested employees who terminate before age 55. Pensions are now based on a new point system (age plus service) which pays graduated pensions to terminating members.

Total worldwide expense for all employee pension plans of Texaco, including pension supplementations and smaller non-U.S.

plans, was $41 million in 1999 and $92 million in 1998 and 1997.

The following data are provided for principal U.S. and non-U.S. plans:

	Pension Benefits				Other U.S. Benefits	
	1999		1998			
(Millions of dollars) As of December 31	**U.S.**	**Int'l**	U.S.	Int'l	**1999**	1998
Changes in Benefit (Obligations)						
Benefit (obligations) at January 1	**$ (1,884)**	**$ (979)**	$ (1,769)	$ (835)	**$ (773)**	$ (756)
Service cost	**(46)**	**(25)**	(60)	(21)	**(6)**	(9)
Interest cost	**(113)**	**(82)**	(117)	(86)	**(49)**	(50)
Amendments	**(29)**	**(23)**	—	(3)	**12**	—
Actuarial gain/(loss)	**(16)**	**(26)**	(191)	(117)	**59**	8
Employee contributions	**(3)**	**(1)**	(4)	(3)	**(14)**	(12)
Benefits paid	**63**	**62**	64	70	**66**	56
Curtailments/settlements	**364**	**(2)**	193	—	**12**	(7)
Special termination benefits	**—**	**—**	(12)	—	**—**	(3)
Currency adjustments	**—**	**96**	—	16	**—**	—
Acquisitions/joint ventures	**—**	**—**	12	—	**60**	—
Benefit (obligations) at December 31	**$ (1,664)**	**$ (980)**	$ (1,884)	$ (979)	**$ (633)**	$ (773)
Changes in Plan Assets						
Fair value of plan assets at January 1	**$ 1,826**	**$ 1,028**	$ 1,702	$ 900	**$ —**	$ —
Actual return on plan assets	**236**	**151**	293	142	**—**	—
Company contributions	**15**	**26**	90	32	**52**	44
Employee contributions	**3**	**1**	4	3	**14**	12
Expenses	**(7)**	**—**	(6)	(2)	**—**	—
Benefits paid	**(63)**	**(62)**	(64)	(70)	**(66)**	(56)
Currency adjustments	**—**	**(74)**	—	23	**—**	—
Curtailments/settlements	**(364)**	**—**	(176)	—	**—**	—
Acquisitions/joint ventures	**—**	**—**	(17)	—	**—**	—
Fair value of plan assets at December 31	**$ 1,646**	**$ 1,070**	$ 1,826	$ 1,028	**$ —**	$ —
Funded Status of the Plans						
Obligation (greater than) less than assets	**$ (18)**	**$ 90**	$ (58)	$ 49	**$ (633)**	$ (773)
Unrecognized net transition asset	**(7)**	**(1)**	(14)	(14)	**—**	—
Unrecognized prior service cost	**85**	**63**	68	52	**(7)**	4
Unrecognized actuarial (gain)/loss	**(161)**	**(17)**	(93)	4	**(143)**	(92)
Net (liability)/asset recorded in Texaco's Consolidated Balance Sheet	**$ (101)**	**$ 135**	$ (97)	$ 91	**$ (783)**	$ (861)
Net (liability)/asset recorded in Texaco's Consolidated Balance Sheet consists of:						
Prepaid benefit asset	**$ 84**	**$ 373**	$ 72	$ 346	**$ —**	$ —
Accrued benefit liability	**(231)**	**(246)**	(215)	(268)	**(783)**	(861)
Intangible asset	**23**	**8**	23	12	**—**	—
Other accumulated non-owner equity	**23**	**—**	23	1	**—**	—
Net (liability)/asset recorded in Texaco's Consolidated Balance Sheet	**$ (101)**	**$ 135**	$ (97)	$ 91	**$ (783)**	$ (861)
Assumptions as of December 31						
Discount rate	**8.0%**	**8.1%**	6.75%	9.5%	**8.0%**	6.75%
Expected return on plan assets	**10.0%**	**8.8%**	10.0%	8.4%	**—**	—
Rate of compensation increase	**4.0%**	**5.2%**	4.0%	6.1%	**4.0%**	4.0%
Health care cost trend rate	**—**	**—**	—	—	**4.0%**	4.0%

(Millions of dollars) As of December 31	Pension Benefits 1999 U.S.	1999 Int'l	1998 U.S.	1998 Int'l	1997 U.S.	1997 Int'l	Other U.S. Benefits 1999	1998	1997
Components of Net Periodic Benefit Expenses									
Service cost	**$ 46**	**$ 25**	$ 60	$ 21	$ 54	$ 17	**$ 6**	$ 9	$ 6
Interest cost	**113**	**82**	117	86	117	85	**49**	50	49
Expected return on plan assets	**(140)**	**(81)**	(136)	(79)	(132)	(66)	**—**	—	—
Amortization of transition asset	**(6)**	**(12)**	(4)	(10)	(5)	(8)	**—**	—	—
Amortization of prior service cost	**11**	**13**	11	7	10	6	**—**	—	—
Amortization of (gain)/loss	**4**	**(2)**	6	(2)	3	—	**(1)**	(4)	(5)
Curtailments/settlements	**(15)**	**2**	6	—	—	—	**(12)**	1	—
Special termination charges	**—**	**—**	8	—	—	—	**—**	2	—
Net periodic benefit expenses	**$ 13**	**$ 27**	$ 68	$ 23	$ 47	$ 34	**$ 42**	$ 58	$ 50

For pension plans with accumulated obligations in excess of plan assets, the projected benefit obligation and the accumulated benefit obligation were $410 million and $379 million as of December 31, 1999, and $414 million and $383 million as of December 31, 1998. The fair value of plan assets for both years was $0.

In connection with the formation of Equilon, effective January 1, 1998, we transferred to Equilon pension benefit obligations of $12 million and related plan assets of $17 million.

Other U.S. Benefits

We sponsor postretirement plans in the U.S. that provide health care and life insurance for retirees and eligible dependents. Effective October 1, 1999, we introduced an age and service point schedule for eligible participants. Our U.S. health insurance obligation is our fixed dollar contribution. The plans are unfunded, and the costs are shared by us and our employees and retirees. Certain of the company's non-U.S. subsidiaries have postretirement benefit plans, the cost of which is not significant to the company.

As a result of the transfer of employees to the downstream alliances effective April 1, 1999, $58 million of postretirement benefit obligations were also transferred.

For measurement purposes, the fixed dollar contribution is expected to increase by 4% per annum for all future years. A change in our fixed dollar contribution has a significant effect on the amounts we report. A 1% change in our contributions would have the following effects:

(Millions of dollars)	1-Percentage Point Increase	1-Percentage Point Decrease
Effect on annual total of service and interest cost components	$ 4	$ (4)
Effect on postretirement benefit obligation	$ 38	$ (34)

NOTE 12 STOCK INCENTIVE PLAN

Under our Stock Incentive Plan, stock options, restricted stock and other incentive award forms may be granted to executives, directors and key employees to provide motivation to enhance the company's success and increase shareholder value. The maximum number of shares that may be awarded as stock options or restricted stock under the plan is 1% of the common stock outstanding on December 31 of the previous year. The following table summarizes the number of shares at December 31, 1999, 1998 and 1997 available for awards during the subsequent year:

(Shares) As of December 31	1999	1998	1997
To all participants	**15,646,336**	12,677,325	9,607,506
To those participants not officers or directors	**2,020,621**	1,967,715	2,362,273
Total	**17,666,957**	14,645,040	11,969,779

Restricted shares granted under the plan contain a performance element which must be satisfied in order for all or a specified portion of the shares to vest. Restricted performance shares awarded in each year under the plan were as follows:

	1999	1998	1997
Shares	**278,402**	334,798	281,174
Weighted average fair value	**$ 62.78**	$ 61.59	$ 55.09

Stock options granted under the plan extend for 10 years from the date of grant and vest over a two year period at a rate of 50% in the first year and 50% in the second year. The exercise price cannot be less than the fair market value of the underlying shares of common stock on the date of the grant. The plan provides for restored options. This feature enables a participant who exercises a stock option by exchanging previously acquired common stock or who has shares withheld by us to satisfy tax withholding obligations, to receive new options equal to the number of shares exchanged or withheld. The restored options are fully exercisable six months after the date of grant and the exercise price is the fair market value of the common stock on the day the restored option is granted.

We apply APB Opinion 25 in accounting for our stock-based compensation programs. Stock-based compensation expense recognized in connection with the plan was $19 million in 1999, $17 million in 1998 and $18 million in 1997. Had we accounted for our plan using the accounting method recommended by SFAS 123, net income and earnings per share would have been the pro forma amounts below:

	1999	1998	1997
Net income *(Millions of dollars)*			
As reported	**$ 1,177**	$ 578	$ 2,664
Pro forma	**$ 1,107**	$ 524	$ 2,621
Earnings per share *(dollars)*			
Basic — as reported	**$ 2.14**	$ .99	$ 4.99
— pro forma	**$ 2.01**	$ .89	$ 4.91
Diluted — as reported	**$ 2.14**	$ .99	$ 4.87
— pro forma	**$ 2.01**	$ .89	$ 4.79

We used the Black-Scholes model with the following assumptions to estimate the fair market value of options at date of grant:

	1999	1998	1997
Expected life	**2 yrs.**	2 yrs.	2 yrs.
Interest rate	**5.4%**	5.4%	6.0%
Volatility	**29.1%**	22.5%	18.6%
Dividend yield	**3.0%**	3.0%	3.0%

Option award activity during 1999, 1998 and 1997 is summarized in the following table:

	1999		1998		1997	
(Stock options)	**Shares**	**Weighted Average Exercise Price**	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding January 1	**11,616,049**	**$ 59.48**	10,071,307	$ 53.31	9,436,406	$ 42.73
Granted	**2,015,741**	**62.78**	2,388,593	61.56	2,084,902	55.06
Exercised	**(8,163,386)**	**59.24**	(7,732,978)	53.18	(9,533,861)	44.86
Restored	**7,448,018**	**64.55**	6,889,941	60.77	8,103,502	55.32
Canceled	**(819,284)**	**64.48**	(814)	78.08	(19,642)	51.43
Outstanding December 31	**12,097,138**	**62.98**	11,616,049	59.48	10,071,307	53.31
Exercisable December 31	**6,358,652**	**$ 62.57**	5,945,445	$ 58.93	3,197,262	$ 51.21
Weighted average fair value of options granted during the year		**$ 11.21**		$ 8.48		$ 6.92

The following table summarizes information on stock options outstanding at December 31, 1999:

	Options Outstanding			**Options Exercisable**	
Exercisable Price Range (per share)	**Shares**	**Weighted Average Remaining Life**	**Weighted Average Exercise Price**	**Shares**	**Weighted Average Exercise Price**
$ 25.36 – 31.84	**20,323**	**2.4 yrs.**	**$ 29.32**	**20,323**	**$ 29.32**
$ 32.47 – 78.08	**12,076,815**	**6.3 yrs.**	**$ 63.04**	**6,338,329**	**$ 62.67**
$ 25.36 – 78.08	**12,097,138**	**6.3 yrs.**	**$ 62.98**	**6,358,652**	**$ 62.57**

NOTE 13 PREFERRED STOCK AND RIGHTS

Series B ESOP Convertible Preferred Stock

At December 31, 1998, the outstanding shares of Series B ESOP Convertible Preferred Stock (Series B) were held by an ESOP. Dividends on each share of Series B were cumulative and payable semiannually at the rate of $57 per annum.

On June 30, 1999, after we called the Series B for redemption, each share of Series B was converted into 25.736 shares, or 15.1 million shares in total, of common stock.

Series D Junior Participating Preferred Stock and Rights

In 1989, we declared a dividend distribution of one Right for each outstanding share of common stock. This was adjusted to one-half Right when we declared a two-for-one stock split in 1997. In 1998, our shareholders approved the extension of the Rights until May 1, 2004. Unless we redeem the Rights, the Rights will be exercisable only after a person(s) acquires, obtains the right to acquire or commences a tender offer that would result in that person(s) acquiring 20% or more of the outstanding common stock other than pursuant to a Qualifying Offer. A Qualifying Offer is an all-cash, fully financed tender offer for all outstanding shares of common stock which remains open for 45 days, which results in the acquiror owning a majority of the company's voting stock, and in which the acquiror agrees to purchase for cash all remaining shares of common stock. The Rights entitle holders to purchase from the company units of Series D Junior Participating Preferred Stock (Series D). In general, each Right entitles the holder to acquire shares of Series D, or in certain cases common stock, property or other securities, at a formula value equal to two times the exercise price of the Right.

We can redeem the Rights at one cent per Right at any time prior to 10 days after the Rights become exercisable. Until a Right becomes exercisable, the holder has no additional voting or dividend rights and it will not have any dilutive effect on the company's earnings. We have reserved and designated 3 million shares as Series D for issuance upon exercise of the Rights. At December 31, 1999, the Rights are not exercisable.

Series F ESOP Convertible Preferred Stock

At December 31, 1998, the outstanding shares of Series F ESOP Convertible Preferred Stock (Series F) were held by an ESOP. Dividends on each share of Series F were cumulative and payable semiannually at the rate of $64.53 per annum.

On February 16, 1999, after we called the Series F for redemption, each share of Series F was converted into 20 shares, or 1.1 million shares in total, of common stock.

Market Auction Preferred Shares

There are 1,200 shares of cumulative variable rate preferred stock, called Market Auction Preferred Shares (MAPS) outstanding. The MAPS are grouped into four series (300 shares each of Series G, H, I and J) of $75 million each, with an aggregate value of $300 million.

The dividend rates for each series are determined by Dutch auctions conducted at seven-week or longer intervals.

During 1999, the annual dividend rate for the MAPS ranged between 3.59% and 4.36% and dividends totaled $9 million ($7,713, $7,772, $7,989 and $7,935 per share for Series G, H, I and J).

For 1998, the annual dividend rate for the MAPS ranged between 3.96% and 4.50% and dividends totaled $13 million ($11,280, $11,296, $11,227 and $11,218 per share for Series G, H, I and J). For 1997, the annual dividend rate for the MAPS ranged between 3.88% and 4.29% and dividends totaled $11 million ($9,689, $9,650, $9,675 and $9,774 per share for Series G, H, I and J).

We may redeem the MAPS, in whole or in part, at any time at a liquidation preference of $250,000 per share, plus premium, if any, and accrued and unpaid dividends thereon.

The MAPS are non-voting, except under limited circumstances.

NOTE 14 FINANCIAL INSTRUMENTS

We utilize various types of financial instruments in conducting our business. Financial instruments encompass assets and liabilities included in the balance sheet, as well as derivatives which are principally off-balance sheet.

Derivatives are contracts whose value is derived from changes in an underlying commodity price, interest rate or other item. We use derivatives to reduce our exposure to changes in foreign exchange rates, interest rates and crude oil, petroleum products and natural gas prices. Our written policies restrict our use of derivatives to protecting existing positions and committed or anticipated transactions. On a limited basis, we may use commodity-based derivatives to establish a position in anticipation of future movements in prices or margins. Derivative transactions expose us to counterparty credit risk. We place contracts only with parties whose credit-worthiness has been pre-determined under credit policies and limit the dollar exposure to any counterparty. Therefore, risk of counterparty non-performance and exposure to concentrations of credit risk are limited.

CASH AND CASH EQUIVALENTS Fair value approximates cost as reflected in the Consolidated Balance Sheet at December 31, 1999 and 1998 because of the short-term maturities of these instruments. Cash equivalents are classified as held-to-maturity. The amortized cost of cash equivalents at December 31, 1999 includes $67 million of time deposits and $165 million of commercial paper. Comparable amounts at year-end 1998 were $72 million and $109 million.

SHORT-TERM AND LONG-TERM INVESTMENTS Fair value is primarily based on quoted market prices and valuation statements obtained from major financial institutions. At December 31, 1999, our available-for-sale securities had an estimated fair value of $167 million, including gross unrealized gains of $11 million and losses of $6 million. At December 31, 1998, our available-for-sale securities had an estimated fair value of $492 million, including gross unrealized gains of $40 million and losses of $8 million. The available-for-sale securities consist primarily of debt securities issued by U.S. and foreign governments and corporations. The majority of these investments mature within five years.

Proceeds from sales of available-for-sale securities were $750 million in 1999, $1,011 million in 1998 and $1,040 million in 1997. These sales resulted in gross realized gains of $45 million in 1999, $53 million in 1998 and $48 million in 1997, and gross realized losses of $13 million, $22 million and $19 million.

The estimated fair value of other long-term investments qualifying as financial instruments but not included above, for which it is practicable to estimate fair value, approximated the December 31, 1999 and 1998 carrying values of $465 million and $331 million.

SHORT-TERM DEBT, LONG-TERM DEBT AND RELATED DERIVATIVES Refer to Note 9 for additional information about debt and related derivatives outstanding at December 31, 1999 and 1998.

FORWARD EXCHANGE AND OPTION CONTRACTS As an international company, we are exposed to currency exchange risk. To hedge against adverse changes in foreign currency exchange rates, we will enter into forward and option contracts to buy and sell foreign currencies. Shown below in U.S. dollars are the notional amounts of outstanding forward exchange contracts to buy and sell foreign currencies.

(Millions of dollars)	Buy	Sell
Australian dollars	**$ 251**	**$ 37**
British pounds	**1,161**	**145**
Danish kroner	**245**	**39**
Euro	**264**	**40**
New Zealand dollars	**145**	**—**
Other European currencies	**56**	**11**
Total at December 31, 1999	**$ 2,122**	**$ 272**
Total at December 31, 1998	$ 2,953	$ 883

Market risk exposure on these contracts is essentially limited to currency rate movements. At year-end 1999, there were $10 million of unrealized gains and $30 million of unrealized losses related to these contracts. At year-end 1998, there were $8 million of unrealized gains and $19 million of unrealized losses.

We use forward exchange contracts to buy foreign currencies primarily to hedge the net monetary liability position of our European, Australian and New Zealand operations and to hedge portions of significant foreign currency capital expenditures and lease commitments. These contracts generally have terms of 60 days or less. Contracts that hedge foreign currency monetary positions are marked-to-market monthly. Any resultant gains and losses are included in income currently as other costs. At year-end 1999 and 1998, hedges of foreign currency commitments principally involved capital projects requiring expenditure of British pounds and Danish kroner. The percentages of planned capital expenditures hedged at year-end were: British pounds – 90% in 1999 and 54% in 1998; Danish kroner – 94% in 1999 and 40% in 1998. Realized gains and losses on hedges of foreign currency commitments are initially recorded to deferred charges. Subsequently, the amounts are applied to the capitalized project cost on a percentage-of-completion basis, and are then amortized over the lives of the applicable projects. At year-end 1999 and 1998, net hedging gains of $17 million and $50 million, respectively, had yet to be amortized.

We sell foreign currencies under a separately managed program to hedge the value of our investment portfolio denominated in foreign currencies. Our strategy is to hedge the full value of this portion of our investment portfolio and to close out forward contracts upon the sale or maturity of the corresponding investments. We value these contracts at market based on the foreign exchange rates in effect on the balance sheet dates. We record changes in the value of these contracts as part of the carrying amount of the related investments. We record related gains and losses, net of applicable income taxes, to stockholders' equity until the underlying investments are sold or mature.

PREFERRED SHARES OF SUBSIDIARIES Refer to Note 15 regarding derivatives related to subsidiary preferred shares.

PETROLEUM AND NATURAL GAS HEDGING We hedge a portion of the market risks associated with our crude oil, natural gas and petroleum product purchases, sales and exchange activities to reduce price exposure. All hedge transactions are subject to the company's corporate risk management policy which sets out dollar, volumetric and term limits, as well as to management approvals as set forth in our delegations of authorities.

We use established petroleum futures exchanges, as well as "over-the-counter" hedge instruments, including futures, options, swaps and other derivative products. In carrying out our hedging programs, we analyze our major commodity streams for fixed cost, fixed revenue and margin exposure to market price changes. Based on this corporate risk profile, forecasted trends and overall business objectives, we determine an appropriate strategy for risk reduction.

Hedge positions are marked-to-market for valuation purposes. Gains and losses on hedge transactions, which offset losses and gains on the underlying "cash market" transactions, are recorded to deferred income or charges until the hedged transaction is closed, or until the anticipated future purchases, sales or production occur. At that time, any gain or loss on the hedging contract is recorded to operating revenues as an increase or decrease in margins, or to inventory, as appropriate. Derivative transactions not designated as hedging a specific position or transaction are adjusted to market at each balance sheet date. Gains and losses are included in operating income.

At December 31, 1999 and 1998, there were open derivative commodity contracts required to be settled in cash, consisting mostly of basis swaps related to location differences in prices. Notional contract amounts, excluding unrealized gains and losses, were $6,604 million and $4,397 million at year-end 1999 and 1998. These amounts principally represent future values of contract volumes over the remaining duration of outstanding swap contracts at the respective dates. These contracts hedge a small fraction of our business activities, generally for the next twelve months. Unrealized gains and losses on contracts outstanding at year-end 1999 were $195 million and $132 million, respectively. At year-end 1998, unrealized gains and losses were $161 million and $140 million, respectively.

NOTE 15 OTHER FINANCIAL INFORMATION, COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

Texaco Inc. and subsidiary companies have financial liabilities relating to environmental remediation programs which we believe are sufficient for known requirements. At December 31, 1999, the balance sheet includes liabilities of $246 million for future environmental remediation costs. Also, we have accrued $803 million for the future cost of restoring and abandoning existing oil and gas properties.

We have accrued for our probable environmental remediation liabilities to the extent reasonably measurable. We based our accruals for these obligations on technical evaluations of the currently available facts, interpretation of the regulations and our experience with similar sites. Additional accrual requirements for existing and new remediation sites may be necessary in the future when more facts are known. The potential also exists for further legislation which may provide limitations on liability. It is not possible to project the overall costs or a range of costs for environmental items beyond that disclosed above. This is due to uncertainty surrounding future developments, both in relation to remediation exposure and to regulatory initiatives. We believe that such future costs will not be material to our financial position or to our operating results over any reasonable period of time.

Preferred Shares of Subsidiaries

Minority holders own $602 million of preferred shares of our subsidiary companies, which is reflected as minority interest in subsidiary companies in the Consolidated Balance Sheet.

MVP Production Inc., a subsidiary, has variable rate cumulative preferred shares of $75 million owned by one minority holder. The shares have voting rights and are redeemable in 2003. Dividends on these shares were $4 million in 1999, 1998 and 1997.

Texaco Capital LLC, another subsidiary, has three classes of preferred shares, all held by minority holders. The first class is 14 million shares totaling $350 million of Cumulative Guaranteed Monthly Income Preferred Shares, Series A (Series A). The second class is 4.5 million shares totaling $112 million of Cumulative Adjustable Rate Monthly Income Preferred Shares, Series B (Series B). The third class, issued in Canadian dollars, is 3.6 million shares totaling $65 million of Deferred Preferred Shares, Series C (Series C). Texaco Capital LLC's sole assets are notes receivable from Texaco Inc. The payment of dividends and payments on liquidation or redemption with respect to Series A, Series B and Series C are guaranteed by Texaco Inc.

The fixed dividend rate for Series A is 6-7/8% per annum. The annual dividend rate for Series B averaged 5.0% for 1999, 5.1% for 1998 and 5.9% for 1997. The dividend rate on Series B is reset quarterly per contractual formula. Dividends on Series A and Series B are paid monthly. Dividends on Series A for 1999, 1998 and 1997 totaled $24 million for each year. Annual dividends on Series B totaled $6 million for both 1999 and 1998 and $7 million for 1997.

Series A and Series B are redeemable under certain circumstances at the option of Texaco Capital LLC (with Texaco Inc.'s consent) in whole or in part at $25 per share plus accrued and unpaid dividends to the date fixed for redemption.

Dividends on Series C at a rate of 7.17% per annum, compounded annually, will be paid at the redemption date of February 28, 2005, unless earlier redemption occurs. Early redemption may result upon the occurrence of certain specific events.

We have entered into an interest rate and currency swap related to Series C preferred shares. The swap matures in the year 2005. Over the life of the interest rate swap component of the contract, we will make LIBOR-based floating rate interest payments based on a notional principal amount of $65 million. Canadian dollar interest will accrue to us at a fixed rate applied to the accreted notional principal amount, which was Cdn. $87 million at the inception of the swap.

The currency swap component of the transaction calls for us to exchange at contract maturity date $65 million for Cdn. $170 million, representing Cdn. $87 million plus accrued interest. The carrying amount of this contract represents the Canadian dollar accrued interest receivable by us. At year-end 1999 and 1998, the carrying amounts of this swap, which approximated fair value, were $20 million and $16 million, respectively.

Series A, Series B and Series C preferred shares are non-voting, except under limited circumstances.

The above preferred stock issues currently require annual dividend payments of approximately $34 million. We are required to redeem $75 million of this preferred stock in 2003, $65 million (plus accreted dividends of $59 million) in 2005, $112 million in 2024 and $350 million in 2043. We have the ability to extend the required redemption dates for the $112 million and $350 million of preferred stock beyond 2024 and 2043.

Pending Award

In July 1999, the Governing Council of the United Nations Compensation Commission (UNCC) approved an award to Saudi Arabian Texaco Inc. (SAT), a wholly-owned subsidiary of Texaco Inc., of about $505 million, plus unspecified interest, for damages sustained as a result of Iraq's invasion of Kuwait in 1990. Payments to SAT are subject to income tax in Saudi Arabia at an applicable tax rate of 85%. SAT is party to a concession agreement with the Kingdom of Saudi Arabia covering the Partitioned Neutral Zone in Southern Kuwait and Northern Saudi Arabia.

The UNCC funds compensation awards by retaining 30% of Iraqi oil sales revenue under an agreement with Iraq. We do not know when we will receive this award since the timing of payments by the UNCC depends on several factors, including the total amount of all compensation awards, the ability of Iraq to produce and sell oil, the price of Iraqi oil and the duration of U.N. trade sanctions on Iraq. This award will be recognized in income when collection is assured.

Financial Guarantees

We have guaranteed the payment of certain debt, lease commitments and other obligations of third parties and affiliate companies. These guarantees totaled $716 million and $797 million at December 31, 1999 and 1998. The year-end 1999 and 1998 amounts include $336 million and $387 million of operating lease commitments of Equilon, our affiliate.

Exposure to credit risk in the event of non-payment by the obligors is represented by the contractual amount of these instruments. No loss is anticipated under these guarantees.

On December 22, 1999, our 50% owned affiliate, Caltex Corporation (Caltex), settled an excise tax claim with the United States Internal Revenue Service (IRS) for $65 million. The IRS claim related to sales of crude oil by Caltex to Japanese customers beginning in 1980. The original claim was for $292 million in excise taxes, $140 million in penalties and $1.6 billion in interest. In order to litigate this claim, Caltex had arranged for a letter of credit for $2.5 billion. Pursuant to an agreement with the IRS in May 1999, the letter of credit was reduced to $200 million. The letter of credit, which Texaco and its 50% partner, Chevron Corporation, had severally guaranteed, was terminated upon settlement. Resolution of this matter had no significant impact on reported results.

Throughput Agreements

Texaco Inc. and certain of its subsidiary companies previously entered into certain long-term agreements wherein we committed to ship through affiliated pipeline companies and an offshore oil port sufficient volume of crude oil or petroleum products to enable these affiliated companies to meet a specified portion of their individual debt obligations, or, in lieu thereof, to advance sufficient funds to enable these affiliated companies to meet these obligations. In 1998, we assigned the shipping obligations to Equilon, our affiliate, but Texaco remains responsible for deficiency payments on virtually all of these agreements. Additionally, Texaco has entered into long-term purchase commitments with third parties for take or pay gas transportation. At December 31, 1999 and 1998, our maximum exposure to loss was estimated to be $445 million and $500 million.

However, based on our right of counterclaim against Equilon and unaffiliated third parties in the event of non-performance, our net exposure was estimated to be $173 million and $195 million at December 31, 1999 and 1998.

No significant losses are anticipated as a result of these obligations.

Litigation

Texaco and approximately 50 other oil companies are defendants in 17 purported class actions. The actions are pending in Texas, New Mexico, Oklahoma, Louisiana, Utah, Mississippi and Alabama. The plaintiffs allege that the defendants undervalued oil produced from properties leased from the plaintiffs by establishing artificially low selling prices. They allege that these low selling prices resulted in the defendants underpaying royalties or severance taxes to them. Plaintiffs seek to recover royalty underpayments and interest. In some cases plaintiffs also seek to recover severance taxes and treble and punitive damages. Texaco and 24 other defendants have executed a settlement agreement with most of the plaintiffs that will resolve many of these disputes. The federal court in Texas gave final approval to the settlement in April 1999 and the matter is now pending before the U.S. Fifth Circuit Court of Appeal.

Texaco has reached an agreement with the federal government to resolve similar claims. The claims of various state governments remain unresolved.

It is impossible for us to ascertain the ultimate legal and financial liability with respect to contingencies and commitments. However, we do not anticipate that the aggregate amount of such liability in excess of accrued liabilities will be materially important in relation to our consolidated financial position or results of operations.

Report of Management

We are responsible for preparing Texaco's consolidated financial statements in accordance with generally accepted accounting principles. In doing so, we must use judgment and estimates when the outcome of events and transactions is not certain. Information appearing in other sections of this Annual Report is consistent with the financial statements.

Texaco's financial statements are based on its financial records. We rely on Texaco's internal control system to provide us reasonable assurance these financial records are being accurately and objectively maintained and the company's assets are being protected. The internal control system comprises:

> Corporate Conduct Guidelines requiring all employees to obey all applicable laws, comply with company policies and maintain the highest ethical standards in conducting company business,

> An organizational structure in which responsibilities are defined and divided, and

> Written policies and procedures that cover initiating, reviewing, approving and recording transactions.

We require members of our management team to formally certify each year that the internal controls for their business units are operating effectively.

Texaco's internal auditors review and report on the effectiveness of internal controls during the course of their audits. Arthur Andersen LLP, selected by the Audit Committee and approved by stockholders, independently audits Texaco's financial statements. Arthur Andersen LLP assesses the adequacy and effectiveness of Texaco's internal controls when determining the nature, timing and scope of their audit. We seriously consider all suggestions for improving Texaco's internal controls that are made by the internal and independent auditors.

The Audit Committee is comprised of six directors who are not employees of Texaco. This Committee reviews and evaluates Texaco's accounting policies and reporting practices, internal auditing, internal controls, security and other matters. The Committee also evaluates the independence and professional competence of Arthur Andersen LLP and reviews the results and scope of their audit. The internal and independent auditors have free access to the Committee to discuss financial reporting and internal control issues.

Peter I. Bijur
Chairman of the Board and Chief Executive Officer

Patrick J. Lynch
Senior Vice President and Chief Financial Officer

George J. Batavick
Comptroller

Report of Independent Public Accountants

To the Stockholders, Texaco Inc.:

We have audited the accompanying consolidated balance sheet of Texaco Inc. (a Delaware corporation) and subsidiary companies as of December 31, 1999 and 1998, and the related statements of consolidated income, cash flows, stockholders' equity and non-owner changes in equity for each of the three years in the period ended December 31, 1999. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Texaco Inc. and subsidiary companies as of December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999 in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP
February 24, 2000
New York, N.Y.

Supplemental Oil and Gas Information

The following pages provide information required by Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities.

Table I – Net Proved Reserves

The reserve quantities include only those quantities that are recoverable based upon reasonable estimates from sound geological and engineering principles. As additional information becomes available, these estimates may be revised. Also, we have a large inventory of potential hydrocarbon resources that we expect will increase our reserve base as future investments are made in exploration and development programs.

> Proved *developed* reserves are reserves that we expect to be recovered through existing wells with existing equipment and operating methods.

> Proved *undeveloped* reserves are reserves that we expect to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion of development.

Table I

Net Proved Reserves of Crude Oil and Natural Gas Liquids *(Millions of Barrels)* | **Net Proved Reserves of Natural Gas** *(Billions of Cubic Feet)*

	Crude Oil and NGL: Consolidated Subsidiaries					Equity		Natural Gas: Consolidated Subsidiaries					Equity	
	United States	Other West	Europe	Other East	Total	Affiliate – Other East	World-wide	United States	Other West	Europe	Other East	Total	Affiliate – Other East	World-wide
Developed reserves	1,100	50	165	418	1,733	354	2,087	3,360	893	452	96	4,801	136	4,937
Undeveloped reserves	222	6	232	48	508	109	617	368	138	509	4	1,019	17	1,036
As of December 31, 1996	1,322	56	397	466	2,241	463	2,704	3,728	1,031	961	100	5,820	153	5,973
Discoveries & extensions	107	13	34	61	215	4	219	692	26	92	346	1,156	2	1,158
Improved recovery	15	—	65	—	80	18	98	7	—	22	—	29	5	34
Revisions	55	3	11	100	169	22	191	228	75	41	(22)	322	19	341
Net purchases (sales)	413	(2)	(31)	(8)	372	—	372	10	(118)	(7)	(310)	(425)	—	(425)
Production	(145)	(5)	(45)	(66)	(261)	(56)	(317)	(643)	(96)	(81)	(2)	(822)	(17)	(839)
Total changes	445	9	34	87	575	(12)	563	294	(113)	67	12	260	9	269
Developed reserves	1,374	54	210	463	2,101	354	2,455	3,379	792	576	110	4,857	145	5,002
Undeveloped reserves	393	11	221	90	715	97	812	643	126	452	2	1,223	17	1,240
As of December 31, 1997*	1,767	65	431	553	2,816	451	3,267	4,022	918	1,028	112	6,080	162	6,242
Discoveries & extensions	70	2	8	32	112	1	113	599	6	47	98	750	1	751
Improved recovery	136	—	16	3	155	156	311	4	—	7	—	11	3	14
Revisions	46	(15)	22	55	108	137	245	152	(12)	(6)	34	168	10	178
Net purchases (sales)	(38)	—	—	26	(12)	—	(12)	(39)	—	—	250	211	—	211
Production	(157)	(4)	(58)	(71)	(290)	(61)	(351)	(633)	(92)	(112)	(17)	(854)	(25)	(879)
Total changes	57	(17)	(12)	45	73	233	306	83	(98)	(64)	365	286	(11)	275
Developed reserves	1,415	39	246	490	2,190	456	2,646	3,345	688	615	374	5,022	135	5,157
Undeveloped reserves	409	9	173	108	699	228	927	760	132	349	103	1,344	16	1,360
As of December 31, 1998*	1,824	48	419	598	2,889	684	3,573	4,105	820	964	477	6,366	151	6,517
Discoveries & extensions	**66**	**11**	**23**	**23**	**123**	**2**	**125**	**442**	**7**	**93**	**42**	**584**	**5**	**589**
Improved recovery	**34**	**—**	**2**	**29**	**65**	**52**	**117**	**4**	**—**	**2**	**235**	**241**	**1**	**242**
Revisions	**11**	**—**	**36**	**72**	**119**	**(132)**	**(13)**	**285**	**193**	**7**	**427**	**912**	**3**	**915**
Net purchases (sales)	**(9)**	**—**	**—**	**23**	**14**	**—**	**14**	**(81)**	**—**	**—**	**712**	**631**	**—**	**631**
Production	**(144)**	**(4)**	**(53)**	**(75)**	**(276)**	**(60)**	**(336)**	**(550)**	**(79)**	**(104)**	**(27)**	**(760)**	**(26)**	**(786)**
Total changes	**(42)**	**7**	**8**	**72**	**45**	**(138)**	**(93)**	**100**	**121**	**(2)**	**1,389**	**1,608**	**(17)**	**1,591**
Developed reserves	**1,361**	**39**	**261**	**545**	**2,206**	**316**	**2,522**	**3,388**	**865**	**557**	**787**	**5,597**	**131**	**5,728**
Undeveloped reserves	**421**	**16**	**166**	**125**	**728**	**230**	**958**	**817**	**76**	**405**	**1,079**	**2,377**	**3**	**2,380**
As of December 31, 1999*	**1,782**	**55**	**427**	**670**	**2,934**	**546**	**3,480**	**4,205**	**941[a]**	**962**	**1,866**	**7,974[a]**	**134**	**8,108[a]**
*Includes net proved NGL reserves														
As of December 31, 1997	246	—	71	—	317	4	321							
As of December 31, 1998	250	—	68	22	340	6	346							
As of December 31, 1999	**250**	**—**	**74**	**134**	**458**	**1**	**459**							

(a) Additionally, there is approximately 489 BCF of natural gas in Other West which will be available from production during the period 2005-2016 under a long-term purchase associated with a service agreement.

The following chart summarizes our experience in finding new quantities of oil and gas to replace our production. Our reserve replacement performance is calculated by dividing our reserve additions by our production. Our additions relate to new discoveries, existing reserve extensions, improved recoveries and revisions to previous reserve estimates. The chart excludes oil and gas quantities from purchases and sales.

	Worldwide	United States	International
Year 1999	111%	99%	124%
Year 1998	166%	144%	191%
Year 1997	167%	132%	212%
3-year average	148%	126%	174%
5-year average	138%	115%	166%

Table II – Standardized Measure

The standardized measure provides a common benchmark among those companies that have exploration and producing activities. This measure may not necessarily match our view of the future cash flows from our proved reserves.

The standardized measure is calculated at a 10% discount. Future revenues are based on year-end prices for oil and gas. Future production and development costs are based on current year costs. Extensive judgment is used to estimate the timing of production and future costs over the remaining life of the reserves. Future income taxes are calculated using each country's statutory tax rate.

Our inventory of potential hydrocarbon resources, which may become proved in the future, are excluded. This could significantly impact our standardized measure in the future.

Table II – Standardized Measure of Discounted Future Net Cash Flows

	Consolidated Subsidiaries					Equity	
(Millions of dollars)	United States	Other West	Europe	Other East	Total	Affiliate – Other East	Worldwide
As of December 31, 1999							
Future cash inflows from sale of oil & gas, and service fee revenue	**$ 45,281**	**$ 2,668**	**$ 11,875**	**$ 16,890**	**$ 76,714**	**$ 7,646**	**$ 84,360**
Future production costs	**(10,956)**	**(913)**	**(2,264)**	**(2,946)**	**(17,079)**	**(2,254)**	**(19,333)**
Future development costs	**(3,853)**	**(239)**	**(1,749)**	**(1,956)**	**(7,797)**	**(767)**	**(8,564)**
Future income tax expense	**(8,304)**	**(758)**	**(2,428)**	**(7,665)**	**(19,155)**	**(2,340)**	**(21,495)**
Net future cash flows before discount	**22,168**	**758**	**5,434**	**4,323**	**32,683**	**2,285**	**34,968**
10% discount for timing of future cash flows	**(10,816)**	**(327)**	**(1,985)**	**(2,243)**	**(15,371)**	**(887)**	**(16,258)**
Standardized measure of discounted future net cash flows	**$ 11,352**	**$ 431**	**$ 3,449**	**$ 2,080**	**$ 17,312**	**$ 1,398**	**$ 18,710**
As of December 31, 1998							
Future cash inflows from sale of oil & gas, and service fee revenue	$ 23,147	$ 1,657	$ 6,581	$ 4,816	$ 36,201	$ 4,708	$ 40,909
Future production costs	(10,465)	(605)	(2,574)	(2,551)	(16,195)	(1,992)	(18,187)
Future development costs	(4,055)	(142)	(1,695)	(761)	(6,653)	(803)	(7,456)
Future income tax expense	(2,583)	(419)	(715)	(1,023)	(4,740)	(967)	(5,707)
Net future cash flows before discount	6,044	491	1,597	481	8,613	946	9,559
10% discount for timing of future cash flows	(2,626)	(244)	(644)	(167)	(3,681)	(391)	(4,072)
Standardized measure of discounted future net cash flows	$ 3,418	$ 247	$ 953	$ 314	$ 4,932	$ 555	$ 5,487
As of December 31, 1997							
Future cash inflows from sale of oil & gas, and service fee revenue	$ 34,084	$ 2,305	$ 9,395	$ 7,690	$ 53,474	$ 5,182	$ 58,656
Future production costs	(10,980)	(807)	(2,854)	(2,303)	(16,944)	(1,840)	(18,784)
Future development costs	(4,693)	(132)	(1,809)	(749)	(7,383)	(476)	(7,859)
Future income tax expense	(5,512)	(652)	(898)	(3,445)	(10,507)	(1,519)	(12,026)
Net future cash flows before discount	12,899	714	3,834	1,193	18,640	1,347	19,987
10% discount for timing of future cash flows	(5,361)	(252)	(1,424)	(374)	(7,411)	(519)	(7,930)
Standardized measure of discounted future net cash flows	$ 7,538	$ 462	$ 2,410	$ 819	$ 11,229	$ 828	$ 12,057

Table III – Changes in the Standardized Measure

The annual change in the standardized measure is explained in this table by the major sources of change, discounted at 10%.

> *Sales & transfers, net of production costs* capture the current year's revenues less the associated producing expenses. The net amount reflected here correlates to Table VII for revenues less production costs.

> *Net changes in prices, production & development costs* are computed before the effects of changes in quantities. The beginning-of-the-year production forecast is multiplied by the net annual change in the unit sales price and production cost.

> *Discoveries & extensions* indicate the value of the new reserves at year-end prices, less related costs.

> *Development costs incurred during the period* capture the current year's development costs that are shown in Table V. These costs will reduce the previously estimated future development costs.

> *Accretion of discount* represents 10% of the beginning discounted future net cash flows before income tax effects.

> *Net change in income taxes* is computed as the change in present value of future income taxes.

Table III – Changes in the Standardized Measure

	Worldwide Including Equity in Affiliate – Other East		
(Millions of dollars)	**1999**	1998	1997
Standardized measure – beginning of year	**$ 5,487**	$ 12,057	$ 17,966
Sales of minerals-in-place	**(352)**	(160)	(79)
	5,135	11,897	17,887
Changes in ongoing oil and gas operations:			
Sales and transfers of produced oil and gas, net of production costs during the period	**(4,230)**	(3,129)	(4,921)
Net changes in prices, production and development costs	**21,990**	(11,205)	(14,632)
Discoveries and extensions and improved recovery, less related costs	**1,821**	728	2,681
Development costs incurred during the period	**1,598**	1,770	1,976
Timing of production and other changes	**(517)**	(1,170)	(969)
Revisions of previous quantity estimates	**301**	852	1,476
Purchases of minerals-in-place	**895**	48	449
Accretion of discount	**881**	1,916	3,027
Net change in discounted future income taxes	**(9,164)**	3,780	5,083
Standardized measure – end of year	**$ 18,710**	$ 5,487	$ 12,057

Table IV – Capitalized Costs

Costs of the following assets are capitalized under the "successful efforts" method of accounting. These costs include the activities of Texaco's upstream operations but exclude the crude oil marketing activities, geothermal and other non-producing activities. As a result, this table will not correlate to information in Note 6 to the financial statements.

> *Proved properties* include mineral properties with proved reserves, development wells and uncompleted development well costs.

> *Unproved properties* include leaseholds under exploration (even where hydrocarbons were found but not in sufficient quantities to be considered proved reserves) and uncompleted exploratory well costs.

> *Support equipment and facilities* include costs for seismic and drilling equipment, construction and grading equipment, repair shops, warehouses and other supporting assets involved in oil and gas producing activities.

> *The accumulated depreciation, depletion and amortization* represents the portion of the assets that have been charged to expense in prior periods. It also includes provisions for future restoration and abandonment activity.

Table IV – Capitalized Costs

(Millions of dollars)	Consolidated Subsidiaries United States	Other West	Europe	Other East	Total	Equity Affiliate – Other East	Worldwide
As of December 31, 1999							
Proved properties	**$ 20,364**	**$ 304**	**$ 5,327**	**$ 2,273**	**$ 28,268**	**$ 1,085**	**$ 29,353**
Unproved properties	**983**	**139**	**50**	**619**	**1,791**	**335**	**2,126**
Support equipment and facilities	**441**	**267**	**37**	**529**	**1,274**	**975**	**2,249**
Gross capitalized costs	**21,788**	**710**	**5,414**	**3,421**	**31,333**	**2,395**	**33,728**
Accumulated depreciation, depletion and amortization	**(13,855)**	**(298)**	**(3,955)**	**(1,365)**	**(19,473)**	**(1,217)**	**(20,690)**
Net capitalized costs	**$ 7,933**	**$ 412**	**$ 1,459**	**$ 2,056**	**$ 11,860**	**$ 1,178**	**$ 13,038**
As of December 31, 1998							
Proved properties	$ 20,601	$ 515	$ 4,709	$ 1,799	$ 27,624	$ 1,015	$ 28,639
Unproved properties	1,188	53	71	390	1,702	408	2,110
Support equipment and facilities	437	27	37	342	843	768	1,611
Gross capitalized costs	22,226	595	4,817	2,531	30,169	2,191	32,360
Accumulated depreciation, depletion and amortization	(14,140)	(277)	(3,381)	(1,253)	(19,051)	(1,119)	(20,170)
Net capitalized costs	$ 8,086	$ 318	$ 1,436	$ 1,278	$ 11,118	$ 1,072	$ 12,190

Table V – Costs Incurred

This table summarizes how much we spent to explore and develop our existing reserve base, and how much we spent to acquire mineral rights from others (classified as proved or unproved).

> *Exploration costs* include geological and geophysical costs, the cost of carrying and retaining undeveloped properties and exploratory drilling costs.

> *Development costs* include the cost of drilling and equipping development wells and constructing related production facilities for extracting, treating, gathering and storing oil and gas from proved reserves.

> *Exploration and development costs* may be capitalized or expensed, as applicable. Such costs also include administrative expenses and depreciation applicable to support equipment associated with these activities. As a result, the costs incurred will not correlate to *Capital and Exploratory Expenditures.*

On a worldwide basis, in 1999 we spent $4.37 for each BOE we added. Finding and development costs averaged $3.80 for the three-year period 1997-1999 and $3.88 per BOE for the five-year period 1995-1999.

Table V – Costs Incurred

(Millions of dollars)	Consolidated Subsidiaries – United States	Other West	Europe	Other East	Total	Equity Affiliate – Other East	Worldwide
For the year ended December 31, 1999							
Proved property acquisition	**$ 4**	**$ —**	**$ —**	**$ 481**	**$ 485**	**$ —**	**$ 485**
Unproved property acquisition	**39**	**25**	**—**	**27**	**91**	**—**	**91**
Exploration	**204**	**92**	**23**	**224**	**543**	**19**	**562**
Development	**698**	**97**	**319**	**301**	**1,415**	**183**	**1,598**
Total	**$ 945**	**$ 214**	**$ 342**	**$ 1,033**	**$ 2,534**	**$ 202**	**$ 2,736**
For the year ended December 31, 1998							
Proved property acquisition	$ 27	$ —	$ —	$ 199	$ 226	$ —	$ 226
Unproved property acquisition	85	1	—	32	118	—	118
Exploration	417	92	65	277	851	19	870
Development	1,073	25	308	204	1,610	160	1,770
Total	$ 1,602	$ 118	$ 373	$ 712	$ 2,805	$ 179	$ 2,984
For the year ended December 31, 1997							
Proved property acquisition	$ 1,099*	$ —	$ —	$ —	$ 1,099	$ —	$ 1,099
Unproved property acquisition	527*	1	—	23	551	—	551
Exploration	480	15	59	234	788	18	806
Development	1,220	62	419	108	1,809	167	1,976
Total	$ 3,326	$ 78	$ 478	$ 365	$ 4,247	$ 185	$ 4,432

*Includes the acquisition of Monterey Resources on a net cost basis of $1,520 million, which is net of deferred income taxes amounting to $469 million and $245 million for the acquired proved and unproved properties, respectively.

Table VI – Unit Prices

Average sales prices are calculated using the gross revenues in Table VII. Average production costs equal producing (lifting) costs, other taxes and the depreciation, depletion and amortization of support equipment and facilities.

	Average sales prices						Average production costs (per composite barrel)		
	Crude oil and NGL per barrel	**Natural gas per thousand cubic feet**	Crude oil and NGL per barrel	Natural gas per thousand cubic feet	Crude oil and NGL per barrel	Natural gas per thousand cubic feet			
	1999		1998		1997		**1999**	1998	1997
United States	**$ 16.56**	**$ 2.13**	$ 10.14	$ 1.93	$ 16.32	$ 2.32	**$ 4.01**	$ 4.07	$ 3.94
Other West	**14.12**	**.77**	9.65	.92	14.40	1.03	**2.87**	1.86	2.80
Europe	**17.42**	**1.99**	11.73	2.42	18.41	2.42	**6.15**	5.24	5.58
Other East	**15.33**	**.18**	9.61	.38	16.87	1.89	**3.45**	3.65	4.11
Affiliate – Other East	**13.24**	**—**	9.81	—	14.89	—	**3.95**	2.68	3.76

Table VII – Results of Operations

Results of operations for exploration and production activities consist of all the activities within our upstream operations, except for crude oil marketing activities, geothermal and other non-producing activities. As a result, this table will not correlate to the *Analysis of Income by Operating Segments.*

> *Revenues* are based upon our production that is available for sale and excludes revenues from resale of third party volumes, equity earnings of certain smaller affiliates, trading activity and miscellaneous operating income. Expenses are associated with current year operations, but do not include general overhead and special items.

> *Production costs* consist of costs incurred to operate and maintain wells and related equipment and facilities. These costs also include taxes other than income taxes and administrative expenses.

> *Exploration costs* include dry hole, leasehold impairment, geological and geophysical expenses, the cost of retaining undeveloped leaseholds and administrative expenses. Also included are taxes other than income taxes.

> *Depreciation, depletion and amortization* includes the amount for support equipment and facilities.

> *Estimated income taxes* are computed by adjusting each country's income before income taxes for permanent differences related to the oil and gas producing activities, then multiplying the result by the country's statutory tax rate and adjusting for applicable tax credits.

Table VII – Results of Operations

	Consolidated Subsidiaries					Equity	
(Millions of dollars)	United States	Other West	Europe	Other East	Total	Affiliate – Other East	Worldwide
For the year ended December 31, 1999							
Gross revenues from:							
Sales and transfers, including affiliate sales	**$ 2,890**	**$ —**	**$ 617**	**$ 935**	**$ 4,442**	**$ 592**	**$ 5,034**
Sales to unaffiliated entities	**230**	**116**	**498**	**202**	**1,046**	**24**	**1,070**
Production costs	**(943)**	**(39)**	**(435)**	**(252)**	**(1,669)**	**(205)**	**(1,874)**
Exploration costs	**(243)**	**(97)**	**(21)**	**(154)**	**(515)**	**(17)**	**(532)**
Depreciation, depletion and amortization	**(794)**	**(22)**	**(336)**	**(134)**	**(1,286)**	**(109)**	**(1,395)**
Other expenses	**(92)**	**(15)**	**(1)**	**(53)**	**(161)**	**(3)**	**(164)**
Results before estimated income taxes	**1,048**	**(57)**	**322**	**544**	**1,857**	**282**	**2,139**
Estimated income taxes	**(312)**	**(8)**	**(114)**	**(457)**	**(891)**	**(143)**	**(1,034)**
Net results	**$ 736**	**$ (65)**	**$ 208**	**$ 87**	**$ 966**	**$ 139**	**$ 1,105**
For the year ended December 31, 1998							
Gross revenues from:							
Sales and transfers, including affiliate sales	$ 2,570	$ —	$ 438	$ 571	$ 3,579	$ 454	$ 4,033
Sales to unaffiliated entities	218	120	509	122	969	28	997
Production costs	(1,066)	(35)	(400)	(250)	(1,751)	(150)	(1,901)
Exploration costs	(286)	(31)	(53)	(137)	(507)	(16)	(523)
Depreciation, depletion and amortization	(832)	(22)	(422)	(113)	(1,389)	(106)	(1,495)
Other expenses	(198)	—	(4)	(10)	(212)	(1)	(213)
Results before estimated income taxes	406	32	68	183	689	209	898
Estimated income taxes	(49)	(14)	(27)	(166)	(256)	(102)	(358)
Net results	$ 357	$ 18	$ 41	$ 17	$ 433	$ 107	$ 540
For the year ended December 31, 1997							
Gross revenues from:							
Sales and transfers, including affiliate sales	$ 3,492	$ —	$ 495	$ 934	$ 4,921	$ 610	$ 5,531
Sales to unaffiliated entities	312	165	499	178	1,154	43	1,197
Production costs	(986)	(57)	(323)	(249)	(1,615)	(192)	(1,807)
Exploration costs	(238)	(10)	(60)	(195)	(503)	(16)	(519)
Depreciation, depletion and amortization	(735)	(27)	(382)	(129)	(1,273)	(110)	(1,383)
Other expenses	(249)	—	—	(24)	(273)	9	(264)
Results before estimated income taxes	1,596	71	229	515	2,411	344	2,755
Estimated income taxes	(511)	(40)	(85)	(418)	(1,054)	(173)	(1,227)
Net results	$ 1,085	$ 31	$ 144	$ 97	$ 1,357	$ 171	$ 1,528

Supplemental Market Risk Disclosures

We use derivative financial instruments to hedge interest rate, foreign currency exchange and commodity market risks. Derivatives principally include interest rate and/or currency swap contracts, forward and option contracts to buy and to sell foreign currencies, and commodity futures, options, swaps and other instruments. We hedge only a portion of our risk exposures for assets, liabilities, commitments and future production, purchases and sales. We remain exposed on the unhedged portion of such risks.

The estimated sensitivity effects below assume that valuations of all items within a risk category will move in tandem. This cannot be assured for exposures involving interest rates, currency exchange rates, petroleum and natural gas. Users should realize that actual impacts from future interest rate, currency exchange and petroleum and natural gas price movements will likely differ from the disclosed impacts due to ongoing changes in risk exposure levels and concurrent adjustments of hedging derivative positions. Additionally, the range of variability in prices and rates is representative only of past fluctuations for each risk category. Past fluctuations in rates and prices may not necessarily be an indicator of probable future fluctuations.

Notes 9, 14 and 15 to the financial statements include details of our hedging activities, fair values of financial instruments, related derivatives exposures and accounting policies.

DEBT AND DEBT-RELATED DERIVATIVES

We had variable rate debt of approximately $2.8 billion and $2.7 billion at year-end 1999 and 1998, before effects of related interest rate swaps. Interest rate swap notional amounts at year-end 1999 increased by $845 million from year-end 1998.

Based on our overall interest rate exposure on variable rate debt and interest rate swaps at December 31, 1999 (including the interest rate and equity swap), a hypothetical two percentage points increase or decrease in interest rates would decrease or increase net income approximately $52 million.

CURRENCY FORWARD EXCHANGE AND OPTION CONTRACTS

During 1999, the net notional amount of open forward contracts decreased $220 million. This related mostly to a decrease in balance sheet monetary exposures.

The effect on fair value of our forward exchange contracts at year-end 1999 from a hypothetical 10% change in currency exchange rates would be an increase or decrease of approximately $185 million. This would be offset by an opposite effect on the related hedged exposures.

PETROLEUM AND NATURAL GAS HEDGING

In 1999, the notional amount of open derivative contracts increased by $2,207 million, mostly related to natural gas hedging.

For commodity derivatives outstanding at year-end 1999 that are permitted to be settled in cash or another financial instrument, the aggregate effect of a hypothetical 17% change in natural gas prices, a 13% change in crude oil prices and a 14% change in petroleum product prices would not be material to our consolidated financial position, net income or cash flows.

INVESTMENTS IN DEBT AND PUBLICLY TRADED EQUITY SECURITIES

We are subject to price risk on this unhedged portfolio of available-for-sale securities. During 1999, market risk exposure decreased by $325 million. At year-end 1999, a 10% appreciation or depreciation in debt and equity prices would change portfolio fair value by about $17 million. This assumes no fluctuations in currency exchange rates.

PREFERRED SHARES OF SUBSIDIARIES

We are exposed to interest rate risk on dividend requirements of Series B preferred shares of Texaco Capital LLC.

We are exposed to currency exchange risk on the Canadian dollar denominated Series C preferred shares of Texaco Capital LLC. We are exposed to offsetting currency exchange risk as well as interest rate risk on a swap contract used to hedge the Series C.

Based on the above exposures, a hypothetical two percentage points increase or decrease in the applicable variable interest rates and a hypothetical 10% appreciation or depreciation in the Canadian dollar exchange rate would not materially affect our consolidated financial position, net income or cash flows.

MARKET AUCTION PREFERRED SHARES (MAPS)

We are exposed to interest rate risk on dividend requirements of MAPS. A hypothetical two percentage points increase or decrease in interest rates would not materially affect our consolidated financial position or cash flows. There are no derivatives related to MAPS.

Selected Financial Data

Selected Quarterly Financial Data

(Millions of dollars)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
				1999				1998
Revenues								
Sales and services	**$ 6,914**	**$ 8,116**	**$ 9,472**	**$ 10,473**	$ 7,922	$ 7,729	$ 7,481	$ 7,778
Equity in income of affiliates, interest, asset sales and other	**276**	**153**	**205**	**82**	225	315	226	31
	7,190	**8,269**	**9,677**	**10,555**	8,147	8,044	7,707	7,809
Deductions								
Purchases and other costs	**5,450**	**6,356**	**7,448**	**8,188**	6,114	5,972	5,836	6,257
Operating expenses	**559**	**550**	**544**	**666**	580	645	593	690
Selling, general and administrative expenses	**290**	**311**	**270**	**315**	276	296	290	362
Exploratory expenses	**130**	**80**	**72**	**219**	141	90	93	137
Depreciation, depletion and amortization	**361**	**365**	**356**	**461**	388	375	409	503
Interest expense, taxes other than income taxes and minority interest	**216**	**212**	**214**	**279**	249	240	237	233
	7,006	**7,874**	**8,904**	**10,128**	7,748	7,618	7,458	8,182
Income (loss) before income taxes and cumulative effect of accounting change	**184**	**395**	**773**	**427**	399	426	249	(373)
Provision for (benefit from) income taxes	**(15)**	**122**	**386**	**109**	140	84	34	(160)
Income (loss) before cumulative effect of accounting change	**199**	**273**	**387**	**318**	259	342	215	(213)
Cumulative effect of accounting change	**—**	**—**	**—**	**—**	(25)	—	—	—
Net income (loss)	**$ 199**	**$ 273**	**$ 387**	**$ 318**	$ 234	$ 342	$ 215	$ (213)
Total non-owner changes in equity	**$ 179**	**$ 271**	**$ 393**	**$ 316**	$ 239	$ 344	$ 210	$ (221)
Net income (loss) per common share *(dollars)*								
Basic								
Income (loss) before cumulative effect of accounting change	**$ .35**	**$ .50**	**$ .71**	**$ .58**	$ .46	$ .62	$ .38	$ (.43)
Cumulative effect of accounting change	**—**	**—**	**—**	**—**	(.05)	—	—	—
Net income (loss)	**$ .35**	**$ .50**	**$ .71**	**$ .58**	$ .41	$ .62	$ .38	$ (.43)
Diluted								
Income (loss) before cumulative effect of accounting change	**$ .35**	**$ .50**	**$ .71**	**$ .58**	$ .46	$ .61	$ .38	$ (.43)
Cumulative effect of accounting change	**—**	**—**	**—**	**—**	(.04)	—	—	—
Net income (loss)	**$ .35**	**$ .50**	**$ .71**	**$ .58**	$ .42	$ .61	$ .38	$ (.43)

See accompanying notes to consolidated financial statements.

Five-Year Comparison of Selected Financial Data

(Millions of dollars)	**1999**	1998	1997	1996	1995
For the year:					
Revenues	**$ 35,691**	$ 31,707	$ 46,667	$ 45,500	$ 36,787
Net income before cumulative effect of accounting changes	**$ 1,177**	$ 603	$ 2,664	$ 2,018	$ 728
Cumulative effect of accounting changes	**—**	(25)	—	—	(121)
Net income	**$ 1,177**	$ 578	$ 2,664	$ 2,018	$ 607
Total non-owner changes in equity	**$ 1,159**	$ 572	$ 2,601	$ 1,863	$ 592
Net income per common share* *(dollars)*					
Basic					
Income before cumulative effect of accounting changes	**$ 2.14**	$ 1.04	$ 4.99	$ 3.77	$ 1.29
Cumulative effect of accounting changes	**—**	(.05)	—	—	(.24)
Net income	**$ 2.14**	$ .99	$ 4.99	$ 3.77	$ 1.05
Diluted					
Income before cumulative effect of accounting changes	**$ 2.14**	$ 1.04	$ 4.87	$ 3.68	$ 1.28
Cumulative effect of accounting changes	**—**	(.05)	—	—	(.23)
Net income	**$ 2.14**	$ .99	$ 4.87	$ 3.68	$ 1.05
Cash dividends per common share* *(dollars)*	**$ 1.80**	$ 1.80	$ 1.75	$ 1.65	$ 1.60
Total cash dividends paid on common stock	**$ 964**	$ 952	$ 918	$ 859	$ 832
At end of year:					
Total assets	**$ 28,972**	$ 28,570	$ 29,600	$ 26,963	$ 24,937
Debt and capital lease obligations					
Short-term	**$ 1,041**	$ 939	$ 885	$ 465	$ 737
Long-term	**6,606**	6,352	5,507	5,125	5,503
Total debt and capital lease obligations	**$ 7,647**	$ 7,291	$ 6,392	$ 5,590	$ 6,240

*Reflects two-for-one stock split effective September 29, 1997.

See accompanying notes to consolidated financial statements.

Texaco Inc. Board of Directors

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Chief Executive Officer
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New York, NY

THOMAS A. VANDERSLICE
Private Investor
Naples, FL

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Charles H. Price, II
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Thomas A. Vanderslice

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Chief Executive Officer

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Senior Vice President and
Chief Financial Officer

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Worldwide Exploration &
Production

GLENN F. TILTON
Senior Vice President
Global Businesses

WILLIAM M. WICKER
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New Ventures

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Finance & Risk Management

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Chief Technology Officer

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General Counsel

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Shareholder Services

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Commercial Development

JANET L. STONER
Vice President
Human Resources

MICHAEL N. AMBLER
General Tax Counsel

GEORGE J. BATAVICK
Comptroller

IRA D. HALL
Treasurer

MICHAEL H. RUDY
Secretary

CHANGES

> George J. Batavick was elected Comptroller of Texaco Inc., effective April 1, 1999.

> C. Robert Black, Senior Vice President of Texaco Inc., retired on May 1, 1999, after 41 years of service.

> Stephen M. Turner, Senior Vice President of Texaco Inc., retired on June 1, 1999, after 10 years of service.

> James F. Link was elected Vice President of Texaco Inc., effective October 1, 1999.

> Claire S. Farley, Vice President of Texaco Inc., retired on October 1, 1999, after 18 years of service.

> Ira D. Hall was elected Treasurer of Texaco Inc., effective October 1, 1999.

> Kjestine M. Anderson, Secretary of Texaco Inc., retired on December 31, 1999, after 20 years of service.

> Michael H. Rudy was elected Secretary of Texaco Inc., effective January 1, 2000.

> Bruce S. Appelbaum was elected Vice President of Texaco Inc., effective March 1, 2000.

> Clarence P. Cazalot, Jr., Vice President of Texaco Inc., retired on March 3, 2000, after 27 years of service.

Investor Information

COMMON STOCK — MARKET AND DIVIDEND INFORMATION:

Texaco Inc. common stock (symbol TX) is traded principally on the New York Stock Exchange. As of February 24, 2000, there were 198,698 shareholders of record. In 1999, Texaco's common stock price reached a high of $70 1/16, and closed December 31, 1999, at $54 5/16.

	Common Stock Price Range				Dividends	
	High	**Low**	High	Low		
	1999		1998		**1999**	1998
First Quarter	**$ 59 3/16**	**$ 44 9/16**	$ 65	$ 49 1/16	**$ .45**	$ .45
Second Quarter	**70 1/16**	**55 1/8**	63 3/4	55 3/4	**.45**	.45
Third Quarter	**68 1/2**	**60 5/16**	64 7/8	55 1/4	**.45**	.45
Fourth Quarter	**67 3/16**	**52 3/8**	63 7/8	50 1/4	**.45**	.45

STOCK TRANSFER AGENT AND SHAREHOLDER COMMUNICATIONS

FOR INFORMATION ABOUT TEXACO OR ASSISTANCE WITH YOUR ACCOUNT, PLEASE CONTACT:

Texaco Inc.
Investor Services
2000 Westchester Avenue
White Plains, NY 10650-0001
Phone: 1-800-283-9785
Fax: (914) 253-6286
E-mail: invest@texaco.com

NY DROP AGENT

ChaseMellon Shareholder Services
120 Broadway – 13th Floor
New York, NY 10271
Phone: (212) 374-2500
Fax: (212) 571-0871

CO-TRANSFER AGENT

Montreal Trust Company
151 Front Street West – 8th Floor
Toronto, Ontario, Canada M5J 2N1
Phone: 1-800-663-9097
Fax: (416) 981-9507

SECURITY ANALYSTS AND INSTITUTIONAL INVESTORS SHOULD CONTACT:

Elizabeth P. Smith
Vice President, Texaco Inc.
Phone: (914) 253-4478
Fax: (914) 253-6269
E-mail: smithep@texaco.com

ANNUAL MEETING

Texaco Inc.'s Annual Stockholders Meeting will be held at Purchase College, The State University of New York, in Purchase, NY, on Wednesday, April 26, 2000. A formal notice of the meeting, together with a proxy statement and proxy form, is being mailed to stockholders with this report.

INVESTOR SERVICES PLAN

The company's Investor Services Plan offers a variety of benefits to individuals seeking an easy way to invest in Texaco Inc. common stock. Enrollment in the Plan is open to anyone, and investors may make initial investments directly through the company. The Plan features dividend reinvestment, optional cash investments, and custodial service for stock certificates. Open an account or access your registered shareholder account on the Internet through our new TexLink connection at www.texaco.com. Texaco's Investor Services Plan is an excellent way to start an investment program for family or friends. For a complete informational package, including a Plan prospectus, call 1-800-283-9785, e-mail at invest@texaco.com, or visit Texaco's Internet home page at www.texaco.com.