TEXACO ANNUAL REPORT

1998


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THE world of oil may appear to be falling apart, but in oil things are never quite as bad or as good as they seem. Huge mergers have thrown the industry into confusion as oil prices h
to historic bottoms. Yet, if his
guide, investors who write off energy will
miss opportunities.
True, there has been a wave of bad news:
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Investors Are Buzzing About E
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Collapse in Oil Price

In an era of change intelligence prevails.

A destabilized world economy...

A financial crisis that devastated the economies of Asia spread in successive waves to Russia and Latin America, slashing world gross domestic product growth from a robust 4% increase in 1997 to a meager 1.6% increase in 1998.

slowed growth in the demand for oil...

Annual growth in world oil demand slowed abruptly, from 2 million barrels per day in 1997 to about 400,000 barrels per day in 1998.

increased oil inventories...

OPEC and some non-OPEC producers cut production in the second half of 1998, but year-end oil stocks were at least 200 million barrels higher than normal.

and contributed to falling oil prices.

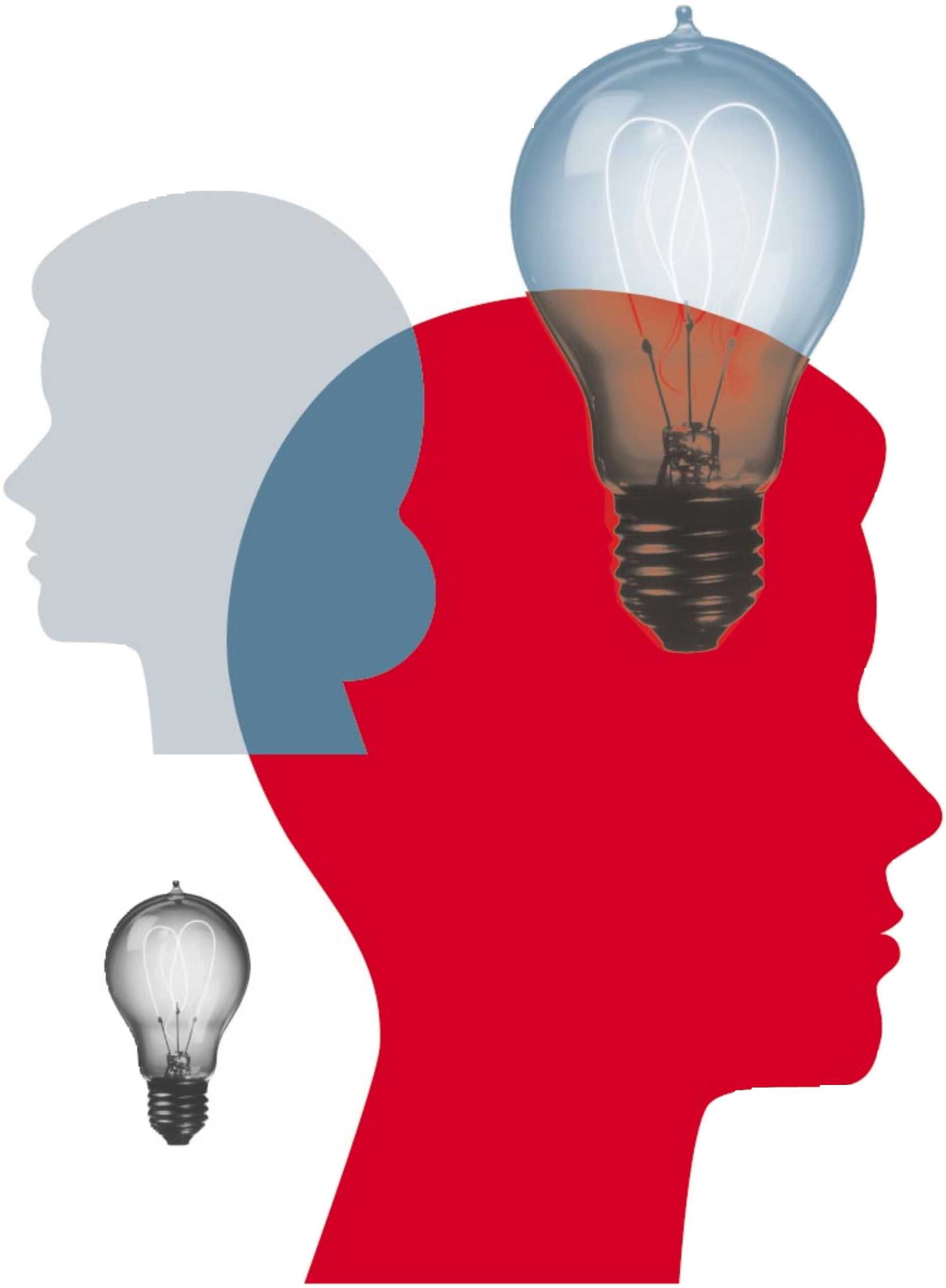
Crude oil prices plunged by 30% from 1997.

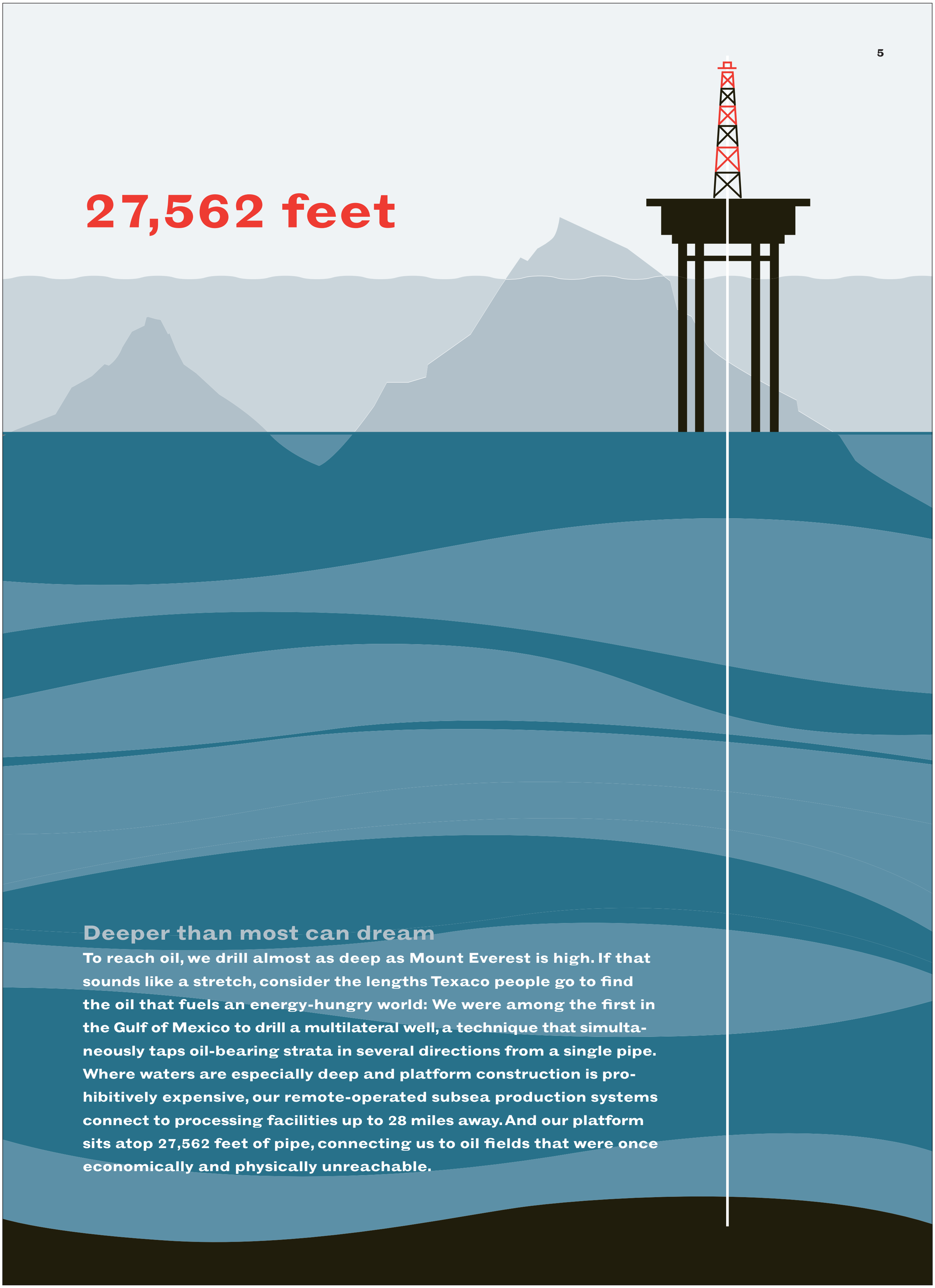
These were the facts of life for everyone in the energy business during 1998. But the energy business is volatile and cyclical by nature. The question is not if there will be tough times, but how to keep adding value in spite of tough times. At Texaco we have a clear vision of what needs to be accomplished, an abundant supply of human and intellectual energy, and the will to get the job done.

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

The energy within us

The challenge of today's market conditions isn't just in the fields or at the gasoline pumps. It exists throughout Texaco, and it's being met with a powerful investment in human energy. We're using technology to reduce the cost of finding and developing oil and gas. We're reorganizing upstream operations to maximize value from existing fields and run leaner. We're focusing on higher-return projects and adding to our reserve base. We've entered into joint ventures to strengthen our downstream position. And we're developing a generation of new and diverse leaders at all levels of our company.





27,562 feet

Deeper than most can dream

To reach oil, we drill almost as deep as Mount Everest is high. If that sounds like a stretch, consider the lengths Texaco people go to find the oil that fuels an energy-hungry world: We were among the first in the Gulf of Mexico to drill a multilateral well, a technique that simultaneously taps oil-bearing strata in several directions from a single pipe. Where waters are especially deep and platform construction is prohibitively expensive, our remote-operated subsea production systems connect to processing facilities up to 28 miles away. And our platform sits atop 27,562 feet of pipe, connecting us to oil fields that were once economically and physically unreachable.

Reduce, reuse, recycle

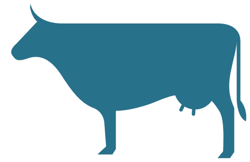
Because Texaco benefits from the world's natural resources, we have an obligation to find and use those resources with utmost care and efficiency. Reducing, reusing and recycling are not only the right things to do, they are good business. Our operations now help irrigate deserts and illuminate cities: In California, we're treating millions of gallons of water a day as part of our extraction process to help grow crops in the parched San Joaquin Valley. We're using cogeneration — producing electrical power and steam from a single energy source — to convert fuels such as natural gas to electricity for home and industrial use. Worldwide, our leading gasification technology enables refiners, utilities and others to make fuel, power and chemical products more efficiently, reducing emissions and waste.

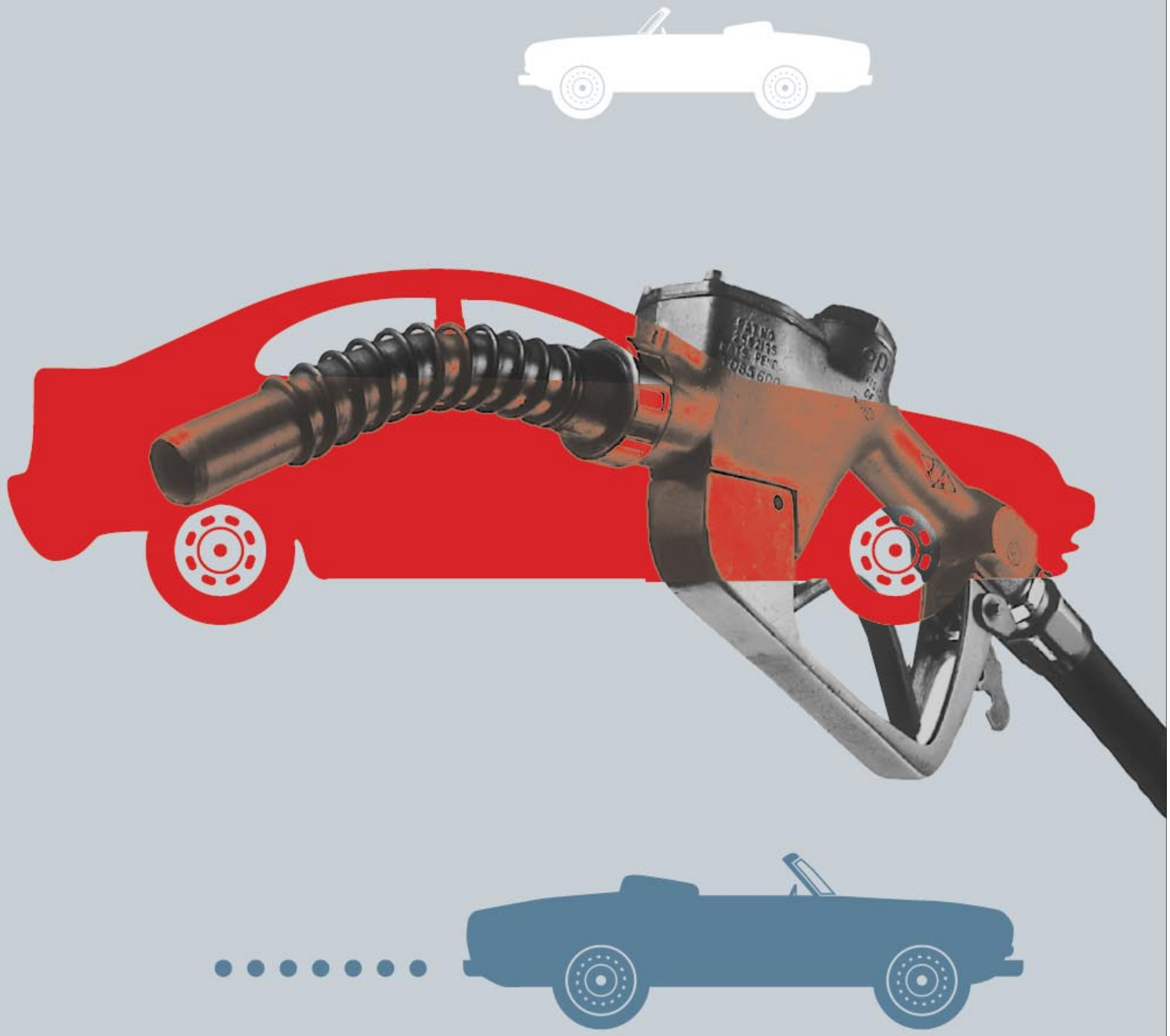
Virtual exploration, real rewards

Texaco exploration teams take their hunt for oil and gas indoors, equipped with the world's best data and technology. Over land, information is gathered by aircraft outfitted with ground-penetrating radar and electromagnetic scanners. At sea, data from reflected sound waves are collected by mobile hydrophone buoys that Texaco adapted from Cold War-era submarine-detection technology. Texaco geoscientists model these data into clear, 3-D images, pinpointing high-potential oil and gas deposits. "Seeing" into the Earth before drilling means a massive reduction in time and cost. What used to take weeks and months now takes hours and days. In the field, "virtual" exploration is yielding outstanding results, discovering real oil and natural gas from the United States to Trinidad, West Africa and the Middle East.

100% lean

Texaco now competes in some markets where a gallon of gasoline costs less than a gallon of milk. That stark fact underscores the challenge Texaco and our industry face: how to maintain acceptable returns during a low-price cycle. The answer is to drive costs lower and maximize the return on assets wherever possible. While our oil and gas production was up 9% in 1998 and has grown by a total of 19% since 1995, we're still reducing our overhead and production costs. Our lifting costs and our finding and development costs already rank among the industry's best.





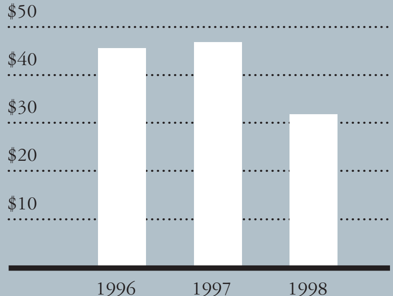
Priming the pump

Texaco and its joint venture partners Shell and Saudi Refining, Inc. are together the largest gasoline marketers in the U.S., with approximately 23,600 outlets and a 15 percent market share. These alliances — Equilon Enterprises and Motiva Enterprises — are on their way to capturing about $800 million in annual savings (over $300 million for Texaco alone) that we anticipated when we created them in 1998. With Chevron, our Fuel and Marine Marketing joint venture is expected to yield more efficiency and growth opportunities. Globally, our longstanding Caltex affiliate, whose 13 refineries in 10 countries support about 8,000 retail outlets, is reorganizing to improve its competitiveness in the Asia-Pacific market and save Texaco $25 million annually.

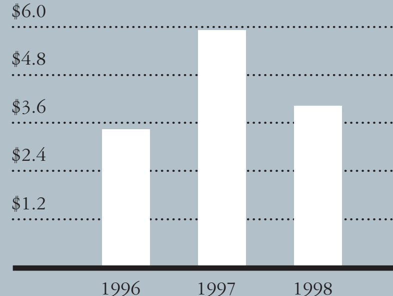
Financial Highlights

(Millions of dollars, except per share amounts in dollars and ratio data)	1998	1997
Revenues	$ 31,707	$ 46,667
Income before special items and cumulative effect of accounting change	$ 894	$ 1,894
Diluted per common share	$ 1.59	$ 3.45
Return on average capital employed	6.5%	13.0%
Net income	$ 578	$ 2,664
Diluted per common share	$ .99	$ 4.87
Return on average capital employed before cumulative effect of accounting change	5.0%	17.3%
Cash dividends paid		
Common	$ 952	$ 918
Per share	$ 1.80	$ 1.75
Preferred	$ 53	$ 55
Total assets	$ 28,570	$ 29,600
Total debt	$ 7,291	$ 6,392
Stockholders' equity	$ 11,833	$ 12,766
Capital and exploratory expenditures	$ 4,019	$ 5,930
Per common share		
Common stockholders' equity	$ 21.24	$ 22.75
Market price at year-end	$ 53.00	$ 54.38
Return on average stockholders' equity before cumulative effect of accounting change	4.9%	23.5%
Total debt to total borrowed and invested capital	36.8%	32.3%

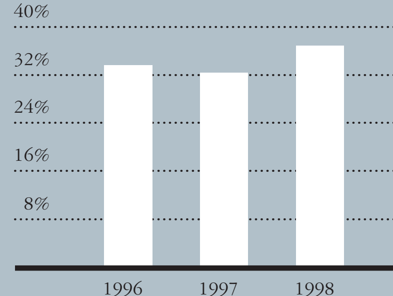
TOTAL REVENUES
(Billions of dollars)



CAPITAL AND EXPLORATORY EXPENDITURES
(Billions of dollars)



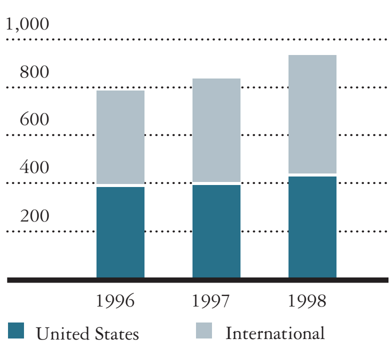
TOTAL DEBT TO TOTAL BORROWED AND INVESTED CAPITAL
(Percent)



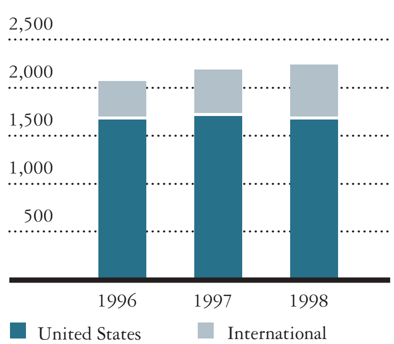
Operational Highlights

	1998	1997
Net production of crude oil and natural gas liquids (Thousands of barrels a day)		
United States	433	396
International	497	437
Total	930	833
Net production of natural gas – available for sale (Millions of cubic feet a day)		
United States	1,679	1,706
International	548	471
Total	2,227	2,177
Natural gas sales (Millions of cubic feet a day)		
United States	3,873	3,584
International	664	592
Total	4,537	4,176
Refinery input (Thousands of barrels a day)		
United States	698	747
International	832	804
Total	1,530	1,551
Refined product sales (Thousands of barrels a day)		
United States	1,203	1,022
International	1,685	1,563
Total	2,888	2,585
Worldwide net proved reserves as of year-end		
Crude oil and natural gas liquids (Millions of barrels)	3,573	3,267
Natural gas (Billions of cubic feet)	6,517	6,242

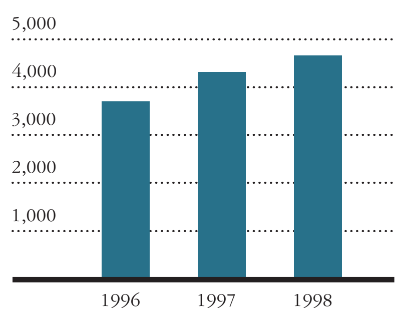
NET PRODUCTION OF CRUDE OIL AND NATURAL GAS LIQUIDS
(Thousands of barrels a day)



NET PRODUCTION OF NATURAL GAS AVAILABLE FOR SALE
(Millions of cubic feet a day)



WORLDWIDE NET PROVED RESERVES
(Millions of barrels of oil equivalent)



To Our Stockholders:

1998 was the toughest time we have faced in my 33 years with the Company. Despite an excellent operational performance, our financial results were sharply lower than the outstanding results we turned in for 1997.

Although our financial results may not show it, we did what we said we would do in 1998. We achieved our key operational goals by increasing production 9% over 1997, replacing 166% of our production and making a significant exploration discovery in Nigeria. Also, our new joint ventures with Shell and Saudi Refining, Inc. in the U.S. downstream are up and running. However, all of this was not enough to offset the disappointing impact that low commodity prices had on the price of our stock.

A difficult price environment, however, is an excuse we simply don't accept. Our goal is to outperform our competitors in creating shareholder value, whatever the price environment.

That is why we made tough choices in 1998, and why we are continuing to take disciplined actions to keep the Company strong and healthy in this challenging environment. And when the market recovers, we will be ready to quickly seize opportunities and make the best use of the technologies and streamlined structure that are revitalizing our business.

In this letter, I first want to discuss the state of the energy business. Then I'll describe the actions that we are taking to invigorate our operations and grow shareholder value.

The Competitive Landscape Has Changed

Oil prices for West Texas Intermediate fell from an average of $20.61/barrel in 1997 to $14.39/barrel in 1998. This $6.22 drop in price represented a reduction of almost $1 billion in 1998 earnings to Texaco, and similar declines for most of our competitors.

The primary reason for the stunning drop in oil prices has to do with supply and demand. In 1997, Asia suffered a rapid and unexpected financial crisis, which in turn spawned a precipitous worldwide economic slowdown. Demand for oil and other energy products is highly sensitive to increases in Gross Domestic Product, so that when economies almost stalled around the world, the demand growth for our commodities also slowed sharply.

A stubborn expansion of supply in early 1998 exacerbated this market weakness. Even though OPEC and a few non-OPEC producers moved to stem the growing surplus by mid-1998, these actions were "too little, too late." This, along with other factors such as a mild winter in the Northern Hemisphere, has caused inventories of crude and refined products to remain high.

We already see the beginnings of an economic recovery in parts of Asia. Also, capital expenditure cutbacks by almost all oil and gas companies have already resulted in a reduction of

crude oil and natural gas production. OPEC may well react to the oversupply by reducing its output, which would also help stabilize prices. Looking beyond the current economic downturn, we see signs of a cyclical upturn in 2000.

Frankly, however, even with these encouraging signs, oil prices may not readily return to their historical price range. Prices may have also adjusted to another structural factor: the efficiencies created by new technology.

Technologies such as horizontal drilling, "smart" downhole technologies, 3-D seismic visualization, and floating ship producing operations have enabled the industry to locate, drill, produce and transport oil and gas much more efficiently than ever before. As an industry, we have reduced the cost and the cycle times required to bring hydrocarbons to market. Technology has not only made it easier to do our business; it may have changed the economics of our business.

Mergers Among Our Competitors

Some of our competitors have reacted to the new competitive marketplace by consolidating. BP and Amoco announced they were joining forces in August, Exxon/Mobil and Total/Petrofina last December. At Texaco, we are constantly evaluating the changed competitive landscape and assessing what actions will create the most value for our shareholders, including mergers and acquisitions. We have also taken steps to improve our competitive position. Let me describe two of them:

First, we are already achieving the benefits of mergers in one of our most significant businesses, the U.S. refining, marketing, trading and transportation and lubricants operations — and we did it two years before our competitors. The U.S. remains a strong market for gasoline, having grown a surprising 2.4% last year.

Our alliances with Shell and Saudi Refining, Inc., announced in 1997, are the largest downstream enterprises in the United States, with about $16.8 billion of assets, accounting for some 15% of the nation's market share.

We expect that our alliances will produce, proportionately, a larger magnitude of cost savings than those announced by our merging competitors...and that they will produce them quicker. Together with our partners, we have already completed the complicated job of weaving our organizations together. Our competitors have yet to face this difficult and time-consuming task.

We will accomplish similar efficiencies on a smaller scale with our worldwide Fuel and Marine Marketing venture with Chevron. We are convinced that, with selective joint ventures such as these, we can achieve the same benefits and cost savings as mergers, but targeted to specific business needs.

Second, in the upstream, we are well positioned with our high-potential set of opportunities, notably in West Africa, Kazakhstan and the Gulf of Mexico. One of the areas we set about improving over the last two years was our exploration program, and I am pleased to report that we have achieved considerable success. We are especially encouraged by our recent Nigerian discovery.

How to Grow Value

FIRST, ASSURE PRODUCTION IS PROFITABLE

The changed marketplace has compelled us to modify the strategies we developed when oil prices were higher. For example, we will keep our production volumes to about the same level they were in 1998 and concentrate on maximizing per-barrel profits by driving down costs.

SECOND, FIND EFFICIENCIES

We have identified over $450 million in annual pre-tax cost savings in 1999 from expense reductions at various businesses including synergies in the U.S. downstream ventures and restructuring in Caltex and the Exploration and Production organization. As a result of these efforts, we made the hard decision to eliminate about 3,000 jobs. In 1999, we are attempting to accelerate $200 million in cost savings that were planned for 2000. We hope to achieve a total of $650 million of efficiencies for 1999 and every year thereafter.

However, we aren't just cutting costs; we are changing the way we do business. For example, as part of the upstream restructuring that we expect will save $100 million this year and $200 million annually in 2000 and beyond, we analyzed the "value creation chain" for this business. This is the life cycle of oil and gas reserves that moves from discovery through commercialization and production and finally to sale or disposal. Three of our most talented and experienced corporate officers have been given primary responsibility for each important phase of the cycle so that we can realize greater value during every stage of asset life.

In another example, we and our partner Chevron have restructured and flattened the operations in our Caltex joint venture, positioning it to outperform our competitors in the promising Asia-Pacific growth area. Over the next five years, this area will add nearly as many people as now reside in the entire United States. We are moving the heart of this operation to Singapore, so that the senior management team will have a closer "line of sight" with the business units, which should speed cycle time and improve decision-making. In addition to reducing $50 million of Caltex expense in 1999, it will also help us develop closer relationships within countries and with our customers. When the Asian economies rebound, Caltex will be revitalized and positioned to be the pre-eminent competitor in this theatre of operations.

THIRD, SEIZE OPPORTUNITIES IN THE DOWNSTREAM BUSINESSES

In this low crude oil price environment, we will focus on the more profitable refining and marketing businesses around the world. I have already discussed our ambitions in the growing U.S. marketplace and in the Asia-Pacific areas.

In the last two years, we have achieved a $160 million turnaround in our European refining and marketing operations through an aggressive strategy of profitable growth, focused expense containment and customer satisfaction. Our Latin American and Caribbean operations continued their outstanding performance last year, earning in excess of $300 million. We will continue our drive towards revenue growth and profitability in both of these areas during 1999.

FOURTH, JUDICIOUS CAPITAL EXPENDITURES AND CASH CONTROL

We reduced our capital budgets for 1998 and 1999. As we proceed through the year we will test our capital expenditures to ensure that we find the optimal balance between conserving cash and funding projects with the greatest opportunities to provide higher returns and grow stockholder value.

At the end of 1998 our debt to total debt and equity ratio was 36.8%, well within our target range of 35–40%. Maintaining our rates in this range gives us the financial flexibility to use our debt capacity together with our stock to participate in acquisition opportunities, fund our capital requirements and pay a competitive dividend.

FIFTH, ENGAGE THE ORGANIZATION

Our compensation programs are designed to align rewards for employees at all levels with stockholder value. For example, most employees participate in a bonus program linked to our competitive positioning in earnings growth and total return to stockholders. If we rank lower than fifth compared to our peers, there are no payouts under the program.

We have linked compensation to performance to a much greater degree for senior executives and officers. In 1999, for example, because we are committed to aligning our compensation with the fortunes of our stockholders, top managers at Texaco will forego salary increases.

Our Workforce: The Energy Within Texaco

One of Texaco's distinctive advantages is our workforce, which is characterized by dedicated, energetic people who consistently deliver outstanding results. I thank every one of them for their hard work and their astonishing spirit and drive, especially in this extremely difficult time.

We are also committed to protecting our employees. In 1998, we renewed our emphasis on safety to ensure that our employees and contractors work in safe environments every day. We also formed a Safety Council to assess our facilities and ensure we are employing the best safety practices in industry.

Similarly, we are performing environmental assessments in several areas, including a baseline of greenhouse gas emissions and audits of our worldwide producing operations, to

ensure that our practices are consistent with the highest levels of environmental protection and conservation in industry.

We are committed to developing our fine workforce and to developing outstanding leaders. We are developing systematic methods to honestly assess the talents and needs of our employees and help them develop their skills to advance in their careers. In addition, we have developed a comprehensive system for evaluating the leadership skills of all managers and supervisors throughout our organization.

Because strong leadership is the single most important way to achieve sustained competitive advantage, the nine members of the Executive Council, including me, are all committed to recruit, develop and challenge talented leaders inside and outside of the organization. I have personally taken responsibility for developing up to 125 promising employees working in every area and at all levels of the Company.

We are making progress in our diversity initiatives, despite the tough economic circumstances in our industry. In 1998, 58% of our hires and 48.6% of our promotions went to highly talented women and minorities. The fresh insights and ideas brought by employees with diverse backgrounds and skills are broadening our already accomplished workforce and helping us to better reflect and understand the marketplace in which we operate.

We are also pleased that we have exceeded our 1998 commitment to spend $176 million with minority and women-owned business enterprises by spending $230 million or 8.3% of our total discretionary expenditures. After just two years we are more than halfway to meeting our five-year goal of spending $1 billion with these firms.

Texaco Foundation: Music, Math and Science

We have given our Texaco Foundation a new focus, which is linked to our future workforce needs and the educational needs in the next century. Our Foundation is now guided by two simple beliefs: 1) that early childhood learning is critical to educational achievement and 2) the workforce of the next century must include a diverse pool of scientists and engineers. Our Foundation is encouraging schoolchildren's natural curiosity about science through interactive, "hands on" learning programs.

We are especially interested in the role that music plays in improving children's educational achievement, particularly in math and science. Texaco has a special understanding of the power of music, due to our decades-long affiliation with the Metropolitan Opera. Some promising research points to a link between early music education and the reasoning skills essential for the successful study of mathematics and science. To advance the understanding in this area, we are funding school programs for very young children that explore the link between music education and math and science.

We are hopeful that through these programs, we can help to develop the mathematicians, physicists, astronomers, environmental scientists, petroleum engineers and geologists for the 21st century.

* * *

We are fortunate to have added two outstanding new directors to our Board, A. Charles Baillie and Charles R. Shoemate. Their leadership positions in the fields of international banking and consumer products will be a great complement to our Board.

We would like to say a grateful farewell to Directors Willard C. Butcher and Dr. John Brademas, who are retiring from our Board after many years of distinguished service. We thank them for their dedication, their exceptional contributions and unfailing encouragement.

And finally, as always, we extend our thanks to our stockholders and customers for your continuing support, especially during these challenging times. We are confident that as the world economy gains momentum — and it will — your Company will be poised to energetically seize the opportunities.

Peter I. Bijur

PETER I. BIJUR
Chairman of the Board and Chief Executive Officer
February 25, 1999

Texaco At A Glance

Operating in more than 150 countries, Texaco and its affiliates explore for, find, produce and sell crude oil, natural gas liquids (NGLs) and natural gas; manufacture and market high-quality fuels and lubricant products; operate trading, transportation and distribution facilities and produce electricity or alternate forms of energy for power and manufacturing.

Strengths

Strong balance sheet.Commitment to ensure long-term success by growing profitable production through application of leading-edge technology. Fiscal discipline to operate effectively in low-price environment. Dedicated workforce. More than 60 years of alliance management.

1998 Performance

Weak demand and oversupply caused earnings to drop sharply: income before special items was $894 million. Despite low-price environment, production and refined product sales increased.

Strategies

Develop and nurture growth businesses by dedicating appropriate capital and human resources to them. Either fix under-performing businesses or sell them to free up capital. Achieve operational excellence in all areas of our business. Develop a world-class, diverse workforce, with explicit leadership development at all levels. Enhance Texaco's image, reputation and brand by everything we do.

Exploration and Production

We seek, find and produce crude oil, NGLs and natural gas from a global portfolio of fields. Our exploration program is concentrated in the deepwater Gulf of Mexico, West Africa and Latin America, while our core production areas extend to other areas of the U.S., the North Sea, the Middle East and the Pacific Rim.

Strengths

Strong commitment to fast-tracking production from new fields, while reducing lifting costs and finding and development costs. Focused exploration program to strengthen acreage position in core areas while exiting properties that no longer fit asset portfolio. Effective allocation of capital and application of leading-edge technologies.

1998 Performance

We restructured our worldwide upstream operations to reduce costs and generate long-term opportunities. We increased production by 9%. We replaced 166% of our worldwide production while cutting finding and development costs by 9%. We outranked the industry in production growth. We made potentially significant discoveries in Dolphin Deep and Starfish fields offshore Trinidad and Block 216 offshore Nigeria.

Strategies

Invest in growth through balanced program of acquisitions and discovered reserve opportunities, and exploration in core areas. Leverage technological leadership to drive down lifting costs.

Marketing, Manufacturing and Distribution

Texaco and its affiliates own or have interests in 28 refineries worldwide. With our affiliates and joint-venture companies, we market automotive fuels through some 38,000 branded retail facilities worldwide. Through our global businesses, we manufacture and sell lubricants, coolants, marine and aviation fuel, and natural gas.

Strengths

Worldwide, we are gaining a platform for growth through new alliances — such as our U.S. joint ventures with Shell and Saudi Refining, Inc., which created the number-one U.S. marketer — and restructuring businesses such as our affiliate, Caltex. We continue to maintain a strong presence in Brazil and elsewhere in Latin America and the Caribbean.

1998 Performance

Completed U.S. downstream joint ventures. Increased product sales in the U.S., a strong market turnaround in Europe, robust growth in Latin America and the Caribbean, growth of global lubricants and coolants and organizational efficiencies. Nevertheless, downstream earnings were slightly lower, largely due to weak margins and significant refinery downtime in the U.S. as well as currency losses in the Caltex region.

Strategies

Our global approach is to grow market share, cut costs and fix or sell underperforming businesses. For example: in the U.S., our alliances will capture synergies while serving as a platform for growth. And Caltex will achieve cost savings through a restructuring, which includes a headquarters move to Singapore.

Global Gas and Power

Texaco Global Gas & Power's expertise in power generation and gasification technology complements our natural gas activities worldwide, and frequently enhances our producing and manufacturing operations. With our affiliates and partners, we own, operate and are developing or licensing technology for plants totaling more than 8,200 megawatts of electrical generating capacity.

Strengths

We are strategically positioned to pursue power generation opportunities in areas such as Asia, in the Americas and Europe, which have strong demand for electricity. Our gasification technology is unequaled: Texaco-licensed projects currently represent 55% of the total worldwide market.

1998 Performance

Even during difficult economic times in Asia, a Texaco-led partnership closed project financing on a 700-megawatt power plant in Thailand. We are also participating in a joint venture to own and operate a gasification plant in Singapore, which will supply industrial gases to the chemical industry. Four additional power plants are under development in Italy, the Philippines and Indonesia.

Strategies

We will leverage our strengths in power and gasification technology to pursue power generation opportunities where Texaco has a presence, where we understand the risk/reward tradeoffs and where governments support restructuring and privatization.

Major World Operations

In the U.K. North Sea, we increased daily production by 38%, growing from 112,000 BOE in 1997 to 155,000 BOE in 1998.

Motiva At A Glance

47 product terminals (owns or has interests in)

Approximately 14,200 branded outlets in all or part of 26 states

Estimated 15.5% market share in joint venture area

Equilon At A Glance

66 crude oil and product terminals (owns or has interests in)

Approximately 9,400 branded outlets in all or part of 32 states

Estimated 14.3% market share in joint venture area

Brazil's population is 163 million people and growing. We have about 3,200 service stations — and a 13% retail market share there.

Major Areas of Operations: Upstream

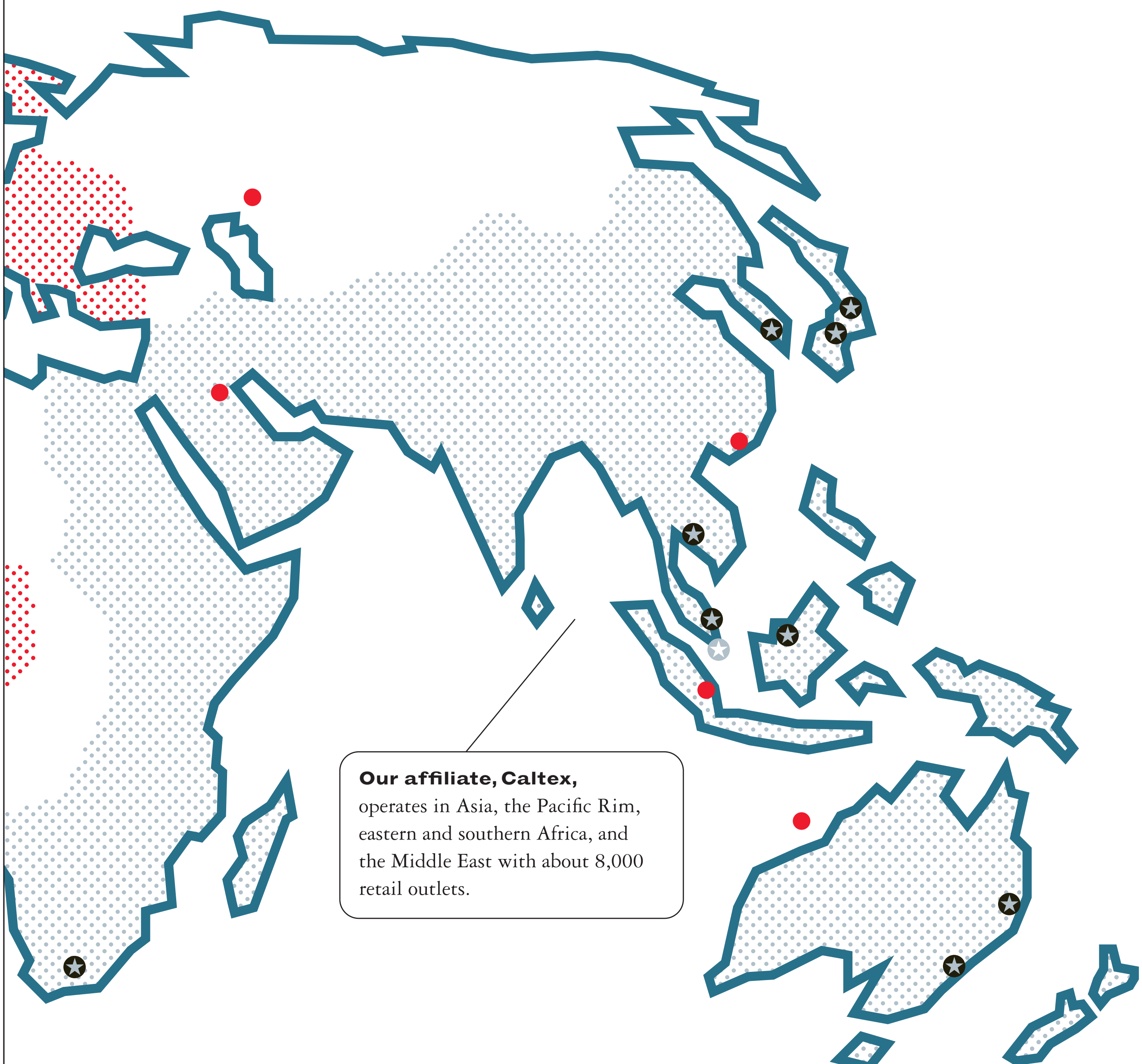
- Texaco's Exploration and Production

Texaco Headquarters

Caltex Headquarters

Major Areas of Operations: Downstream

- Texaco Marketing
- Caltex Marketing
- Caltex Refineries
- Equilon Marketing
- Equilon Refineries
- Motiva Marketing
- Motiva Refineries



Worldwide Businesses

Aviation
Lubricants/Additives/Coolants
Marine Fuels/Lubricants
Exploration and Production

Vital Statistics

Total reserves: nearly 4.7 billion barrels of oil equivalent (BOE)
Total production: 1,301 thousands of BOE a day
Refinery input: 1,530 thousands of barrels a day
Worldwide branded service stations: about 38,000
Refined product sales: 2,888 thousands of barrels a day

Glossary of Terms

API GRAVITY
A measurement of the gravity (weight per unit volume) of crude oil and other liquid hydrocarbons by a system recommended by the American Petroleum Institute (API). The measuring scale is calibrated in terms of "API degrees." The lower the API gravity, the heavier the oil. The higher the API gravity, the lighter the oil.

BARRELS OF OIL EQUIVALENT (BOE)
The volume of natural gas that when burned produces the same amount of heat as a barrel of oil (6,000 cubic feet of gas equals one barrel of oil).

COGENERATION
A process that harnesses a single fuel such as natural gas to produce two forms of energy: electricity and steam or dry heat.

COMPLIANT TOWER
The upper portion of the support pilings of an oil rig, which is designed to flex with the forces of waves, wind and ocean current and is therefore especially suited for deepwater projects.

DELINEATION WELL
A well drilled in an unproven area adjacent to a proven well to determine the extent of the reservoir; also referred to as a "stepout" well.

DOWNHOLE
A term used in exploration and production to describe tools, equipment and instruments used in the well bore. Also, it refers to conditions or techniques applying to the well bore.

DOWNSTREAM
All activities associated with the refining, marketing and transportation of petroleum products.

ENHANCED RECOVERY
Various technologies for increasing or prolonging the productivity of oil and natural gas fields. Common methods include waterflooding and steamflooding.

GASIFICATION
An environmentally superior technology for converting a wide variety of hydrocarbon fuels (coal, heavy oil, petroleum coke, natural gas and wastes) into clean synthetic gas, or "syngas," which is used to produce electricity, industrial chemicals and gases as well as fuels and fertilizers.

HEAVY OIL
A category of crude oil characterized by relatively high viscosity, a higher carbon-to-hydrogen ratio, and heavier specific gravities (weights). In the refining process, heavy crude oil generally yields more "heavy" products such as asphalt.

HORIZONTAL DRILLING
A technique in which the drill bit is turned to move horizontally through a productive reservoir, increasing data about the reservoir and guiding the placement of wells to optimize oil recovery.

HYDROCARBONS
Compounds containing hydrogen and carbon atoms that may be in solid, liquid or gaseous form, and that form the basis of all petroleum products.

LEASE OPERATING EXPENSES
Production expenses and cost of sales excluding exploration expenses, depreciation, depletion, amortization and dry hole expenses.

LIGHT OIL
A category of crude oil characterized by relatively low viscosity, a lower carbon-to-hydrogen ratio, and lower specific gravities (weights). In the refining process, light crude oil generally yields more "light" products such as gasoline.

LIQUEFIED NATURAL GAS (LNG)
Gas, mainly methane, that has been liquefied in a refrigeration and pressure process to facilitate storage and transportation.

LIQUEFIED PETROLEUM GAS (LPG)
A mixture of butane, propane and other light hydrocarbons. At normal temperature it is a gas, but it can be cooled or subjected to pressure to facilitate storage and transportation.

MIDSTREAM
All activities associated with storage and transport of crude oil and natural gas (before processing) via ship, rail, truck or pipeline.

NATURAL GAS
A naturally occurring mixture of hydrocarbons found in porous sedimentary rocks in the earth's crust, usually in association with petroleum deposits.

NATURAL GAS LIQUIDS (NGLs)
A mixed stream of ethane, propane, butane and pentanes that is split into individual components and either sold or used as feedstocks for refineries and chemical plants.

PETROLEUM COKE
Solid carbon or coke retained as a residue in tar stills after high-temperature distillation.

PRODUCED WATER
Water that is produced from a well along with oil and gas.

REFINED PRODUCTS
The marketable processed output of a petroleum refinery. Examples include naphtha, gasoline, kerosene, heating oil, diesel, lubricant base oils and asphalt.

REFINING MARGIN
Similar to gross margin, refining margin represents the composite value of all products produced by the refinery minus the cost of crude. To get the net margin, subtract the overhead and manufacturing costs from the gross margin.

RESERVES
An economically recoverable quantity of crude oil and gas that has not yet been produced from reservoirs.

RESERVOIR
A porous, permeable, sedimentary rock formation containing oil and/or natural gas enclosed or surrounded by layers of less permeable or impervious rock.

STEAMFLOOD TECHNOLOGY
One method of enhanced recovery in which steam is introduced into the reservoir through an injector well, providing heat and pressure to push heavy oil toward the surrounding producing wells.

SYNTHETIC GAS (SYNGAS)
A synthetic fuel created from hydrocarbon feedstocks, which may be used as a building block to produce electricity, industrial chemicals, gases and other petroleum products.

THREE-DIMENSIONAL SEISMIC IMAGING (3D)
A technology that involves bouncing sound waves off formations to create three-dimensional images, which enable oil companies to find likely sites of oil and gas.

UPSTREAM
All activities associated with the exploration and production of crude oil and natural gas.

WTI
An abbreviation for West Texas Intermediate. WTI is a specific grade of crude oil that is a benchmark commodity of the U.S. oil industry.

Financial Table of Contents

Management's Discussion and Analysis

Introduction

In 1996, the Securities and Exchange Commission (SEC) issued plain English guidelines to improve shareholder communications. In 1997, we were the first major energy company to begin writing our Management's Discussion and Analysis (MD&A) in plain English. This year we continue to expand the use of plain English.

We were the first major energy company to write our MD&A in plain English.

In the MD&A, we explain the operating results and general financial condition of our company. The MD&A begins with a table of financial highlights that provides a financial picture of the company. The remainder of our MD&A consists of four main topics: Industry Review, Results of Operations, Analysis of Income by Operating Segments and Other Items.

In the *Industry Review*, we discuss the economic factors that affected our industry in 1998. We also provide our near-term outlook for the industry.

In the *Results of Operations,* we compare and describe 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 events that affect our results but are outside the scope of normal current-year operations.

In the *Analysis of Income by Operating Segments,* we show and discuss our operating segments: Exploration and Production (Upstream), Manufacturing, Marketing and Distribution (Downstream) and Global Gas Marketing. We also show and discuss Other Business Units and our Corporate/Non-operating results. Our discussion focuses on major business factors affecting our results.

In the *Other Items* section, we discuss other important items:

- Liquidity and Capital Resources: Our program to manage cash, working capital and debt and other actions that provide us financial flexibility
- Capital and Exploratory Expenditures: Our program to invest in our 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 new accounting standards to be adopted
- Euro Conversion: The status of our program to convert to the new euro currency
- Year 2000: The status of our program to identify and correct our computers, software and related technologies to be year 2000 compliant

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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 1998 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)	1998	1997	1996
Revenues	$ 31,707	$ 46,667	$ 45,500
Income before special items and cumulative effect of accounting change	$ 894	$ 1,894	$ 1,665
Special items	(291)	770	353
Cumulative effect of accounting change	(25)	—	—
Net income	$ 578	$ 2,664	$ 2,018
Diluted income per common share (dollars)			
Income before special items and cumulative effect of accounting change	$ 1.59	$ 3.45	$ 3.03
Special items	(.55)	1.42	.65
Cumulative effect of accounting change	(.05)	—	—
Net income	$ .99	$ 4.87	$ 3.68
Cash dividends per common share (dollars)	$ 1.80	$ 1.75	$ 1.65
Total assets	$ 28,570	$ 29,600	$ 26,963
Total debt	$ 7,291	$ 6,392	$ 5,590
Stockholders' equity	$ 11,833	$ 12,766	$ 10,372
Current ratio	1.07	1.07	1.24
Return on average stockholders' equity*	4.9%	23.5%	20.4%
Return on average capital employed before special items*	6.5%	13.0%	12.8%
Return on average capital employed*	5.0%	17.3%	14.9%
Total debt to total borrowed and invested capital	36.8%	32.3%	33.6%

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

Industry Review

Introduction

Crude oil prices have a major effect on our financial performance. The price of crude oil is determined in the international market by the often complex interaction of worldwide petroleum demand and supply. In 1998, crude oil prices were driven down by several factors which influenced demand and supply. These included economic activity, weather patterns and actions of the Organization of Petroleum Exporting Countries (OPEC).

For 1998, WTI crude oil prices averaged $14.39 per barrel, or about 30% below the 1997 average.

Review of 1998

In 1998, the world experienced a severe economic crisis. Global economic growth averaged a meager 1.6%, significantly below the 4% growth recorded in 1997 and 1996.

Economic activity varied widely among regions, with many Asian countries hit the hardest. Japan, the world's second-largest economy, experienced its worst downturn in the post-war period, caused by a collapse in consumer and investor confidence and severe banking problems. Several of developing Asia's key economies, including Indonesia, Hong Kong, Korea, Malaysia, Singapore and Thailand also plunged into recession, crippled by a regional financial crisis which began in July 1997.

The financial turbulence eventually spread to Russia and Latin America. Russia's economy registered a steep decline. In Latin America, the heightened financial uncertainty ultimately pushed the large Brazilian economy into recession, and slowed growth in other Latin American countries. Moreover, weak commodity prices — attributable in part to the slowdown in Asia — curtailed economic growth in other areas, particularly the oil producing countries of the Middle East and Africa.

In sharp contrast to the areas experiencing economic recession or stagnation, the U.S. and Western Europe enjoyed favorable economic conditions. U.S. growth remained robust as the economy benefited from lower interest rates, and Western Europe showed an improvement because of higher consumer spending.

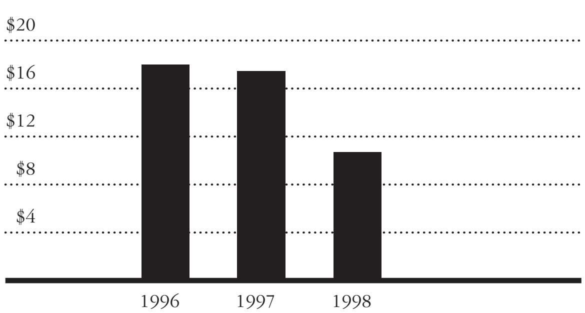
Economic activity has a major effect on petroleum consumption. The deterioration in major portions of the global economy resulted in a substantial reduction in oil demand growth, which increased by only about 400,000 barrels per day (BPD) or 0.5% during 1998. This represents a dramatic slowing from the roughly 2 million BPD growth which occurred in both 1997 and 1996. Demand in Asia suffered the largest decline, about 500,000 BPD. This was a significant development, since growth in Asia had accounted for about half of the total worldwide increase in recent years. Moreover, warm weather at both the beginning and end of 1998 constrained oil consumption in the U.S. and Western Europe.

Crude oil prices were further weakened by significant increases in petroleum supplies early in 1998. Specifically:

- OPEC countries set new, higher production quotas in late 1997 and proceeded to exceed them
- U.N.-sanctioned crude oil exports from Iraq increased sharply
- Production from non-OPEC countries also increased

These actions led to a large increase in worldwide petroleum inventories. By mid-1998, OPEC, Mexico and a few other non-OPEC producers agreed to reduce their combined oil production by about 3 million BPD. Yet, in the face of lower demand, this attempt to improve the growing market imbalance did not prevent the slide in world oil prices. The market price of West Texas Intermediate (WTI) crude oil slipped from an average of about $16.70 per barrel in January to $11.30 per barrel during December.

TEXACO'S U.S. REALIZED CRUDE OIL PRICE PER BARREL
(Dollars)



Prices in 1998 fell to historically low levels.

In addition to lower worldwide crude oil prices, warmer than normal weather and excess capacity caused natural gas prices in the U.S. to decline almost 20%.

Near-Term Outlook

We have begun to see signs of stabilization in the global economic crisis, prompted by various steps taken by the U.S. and other industrialized countries, including:

- The cutting of interest rates by the U.S. Federal Reserve and other central banks
- An increase in the International Monetary Fund's loanable resources by more than $90 billion
- A significant financial rescue package for Brazil
- Japanese banking reform legislation and implementation of fiscal measures to stimulate the economy

Although there are some preliminary indications that the troubled economies of Asia may be bottoming-out, improvements in the region could be partly offset by slower expansions in the U.S., Western Europe and Latin America. In addition, the Russian economy shows no signs of a near-term turnaround. Accordingly, we anticipate only a 1.7% increase in world economic output in 1999.

These elements point to a continued weak oil market in 1999. OPEC's production cuts are due to expire in June, and it is unsure if they will be expanded, or even extended. In the absence of additional large-volume production reductions, high worldwide petroleum inventories are likely to constrain any significant recovery in oil prices through at least mid-1999.

Results of Operations

Revenues

Our consolidated worldwide revenues were $31.7 billion in 1998, $46.7 billion in 1997 and $45.5 billion in 1996. Approximately 80% of the decrease in 1998 resulted 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 decreased in 1998 due to historically low commodity prices throughout our global markets. Crude oil, natural gas and refined product prices were all lower. Partly offsetting lower sales revenue due to declining prices were higher volumes. We continue to expand our production and sales volumes through successful capital investments and focused market expansion. Worldwide production in

1998 increased by 9% following an increase of 6% in 1997. These increases span our global areas of operations including the United States, the U.K. and the Partitioned Neutral Zone. Refined product sales growth included expanded activities in Latin America and Europe. We also expanded our aviation, marine and other refined product trading activities in the U.S., which are handled outside the joint ventures. Natural gas sales also grew as we expanded our marketing activities in the United States.

Other Revenues

Other revenues include our equity in the income of affiliates, income from asset sales and interest income. Results for 1998 show a decrease in other revenues. Equity in income of affiliates decreased in 1998, mostly due to a decline in Caltex' results and special charges recorded by several of our affiliates. This decline was partly offset by the inclusion of results for Equilon. Income from asset sales was also lower in 1998. In 1997 we sold a 15% interest in the U.K. North Sea Captain field and our upstream interests in Myanmar.

Costs and Expenses

Costs and expenses from operations were $30.5 billion in 1998, $42.9 billion in 1997 and $42.0 billion in 1996. Similar to the explanation of revenues, the decrease for both costs and expenses for 1998 is largely due to the equity accounting treatment for our joint venture company, Equilon. The impact of lower prices, which reduced our cost of goods sold, was partly offset by higher purchased volumes.

Special items recorded by our subsidiaries increased costs and operating expenses in 1998 by $382 million. Principal charges were for inventory valuation adjustments, asset write-downs and employee separation costs. Inventory valuation adjustments to reflect lower market prices for crude oil and refined products increased costs by $99 million.

Asset write-downs, which increased depreciation expense by $150 million, resulted from impairments primarily in our upstream operations. These and other asset impairments that we have recognized since initially applying the provisions of SFAS 121 have been driven by specific events, such as the sale of properties or downward revisions in underground reserve quantities, not changes in prices used to calculate future revenues by year. 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. Our present outlook is that prices will recover from their low levels that existed at the end of 1998. If in the future we change this view, asset impairments may result.

Employee separation costs increased our other expenses by approximately $133 million. In the fourth quarter of 1998, we announced reorganizations for several of our operations and began implementing other cost-cutting initiatives to reduce costs and improve focus in growth areas. As a result, we accrued for employee severance costs. The principal units affected were our worldwide upstream operations, our North America natural gas operations, our marketing operations in the U.K. and Brazil, our manufacturing operations in Panama, and our corporate center. We expect that the reorganizations and other initiatives will be substantially completed by the end of the first quarter of 1999. For additional information, see Note 12 to the financial statements.

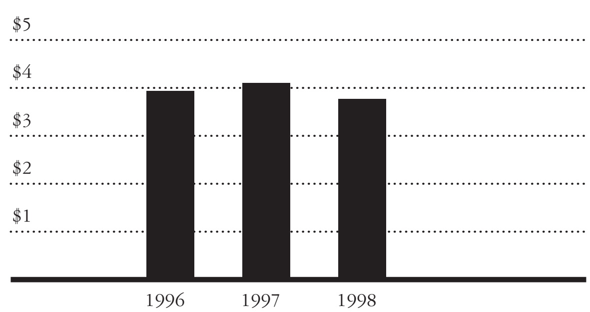
Special charges in 1997 were $136 million principally for asset write-downs and royalty litigation issues, and $152 million in 1996 for employee separation and litigation matters.

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

During 1998 we kept tight control over expenses as we continued to grow our business. Our success is illustrated by the chart below.

CASH EXPENSES PER BARREL

(Dollars) Excludes operations now in Equilon and special items.



Tight controls on expenses led to an 8% reduction per barrel in 1998.

In 1998, we targeted about $650 million in annual pre-tax cost savings through the year 2000.

Income Taxes

Income tax expense was $98 million in 1998, $663 million in 1997 and $965 million in 1996. The decrease in 1998 is mostly due to lower income. The year 1997 included a $488 million benefit for an IRS settlement. The years 1998 and 1996 included benefits of $43 million and $188 million from the sales of interests in a subsidiary.

Income Summary Schedules

The following schedules show 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)	1998	1997	1996
Income before special items and cumulative effect of accounting change	$ 894	$ 1,894	$ 1,665
Special items:			
Inventory valuation adjustments	(142)	—	—
Asset write-downs	(93)	(41)	—
Employee separation costs	(80)	—	(65)
Caltex reorganization	(43)	—	—
U.S. joint venture formation issues	(21)	—	—
Gains on major asset sales	20	367	194
Tax benefits on asset sales	43	—	188
Tax and other issues	25	444	36
Total special items	(291)	770	353
Income before cumulative effect of accounting change	$ 603	$ 2,664	$ 2,018

The following schedule further details our results:

Income (loss)

	Before Special Items			After Special Items		
(Millions of dollars)	1998	1997	1996	1998	1997	1996
Exploration and production						
U.S.	$ 381	$ 1,038	$ 1,074	$ 301	$ 990	$ 1,074
International	172	474	466	120	807	493
Total	553	1,512	1,540	421	1,797	1,567
Manufacturing, marketing and distribution						
U.S.	278	311	236	223	324	210
International	503	524	249	332	508	447
Total	781	835	485	555	832	657
Global gas marketing	(35)	(43)	34	(18)	(43)	34
Total	1,299	2,304	2,059	958	2,586	2,258
Other business units	7	5	10	7	5	10
Corporate/Non-operating	(412)	(415)	(404)	(362)	73	(250)
Income before cumulative effect of accounting change	$ 894	$ 1,894	$ 1,665	$ 603	$ 2,664	$ 2,018

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 were significantly challenged in 1998, due to lower crude oil and natural gas prices. The following discussion will focus on how the low-price environment and other business factors affected our earnings. We will present our U.S. and international results and conclude our discussion with some forward-looking comments. The U.S. results include some minor Canadian operations which were sold in December 1998.

United States Upstream

(Millions of dollars, except as indicated)	1998	1997	1996
Operating income before special items	$ 381	$ 1,038	$ 1,074
Special items:			
Asset write-downs	(51)	(31)	—
Employee separation costs	(29)	—	—
Gains on major asset sales	—	26	—
Tax and other issues	—	(43)	—
Total special items	(80)	(48)	—
Operating income	$ 301	$ 990	$ 1,074
Selected Operating Data:			
Net production			
Crude oil and NGL (thousands of barrels a day)	433	396	388
Natural gas available for sale (millions of cubic feet a day)	1,679	1,706	1,675
Average realized crude price (dollars per barrel)	$ 10.60	$ 17.34	$ 17.93
Average realized natural gas price (dollars per MCF)	$ 2.00	$ 2.37	$ 2.19
Exploratory expenses (millions of dollars)	$ 257	$ 189	$ 153
Production costs (dollars per barrel)	$ 4.07	$ 3.94	$ 3.82
Return on average capital employed before special items	6.0%	21.2%	23.7%
Return on average capital employed	4.8%	20.2%	23.7%

WHAT HAPPENED IN THE UNITED STATES?

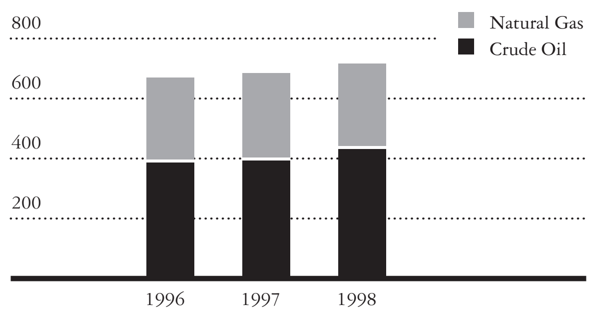
Business Factors

PRICES Lower prices in 1998 reduced earnings by $647 million. Our average realized crude oil price decreased 39% to $10.60 per barrel. This follows a 3% decrease in 1997. In 1998, crude oil prices plummeted to *over 20 year lows* in the fourth quarter. Our average realized natural gas price decreased 16% in 1998 to $2.00 per MCF. This follows an 8% increase in 1997.

PRODUCTION Our production increased 5% in 1998. This follows a 2% increase in 1997. The increases are due to the acquisition of heavy oil producer Monterey Resources in November 1997. We also had new production in the Gulf of Mexico and higher production from our Kern River field in California. These production increases more than offset natural field declines.

Our production increased 5% in 1998 while the U.S. industry average decreased 3%.

U.S. PRODUCTION
(Thousands of barrels of oil equivalent a day)



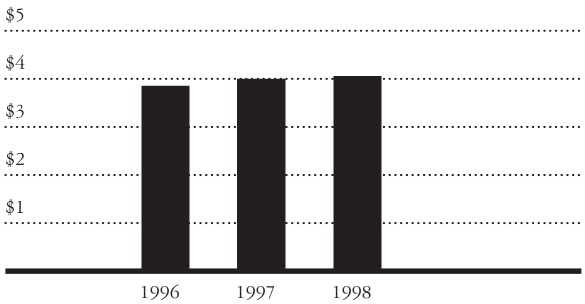
Growth of 5% in 1998 due to higher production in California and the Gulf of Mexico.

EXPLORATORY EXPENSES We expensed $257 million on exploratory activity in 1998, an increase of 36%. In 1998, we continued to focus our exploration efforts in Texas, Louisiana, California and offshore opportunities in the Gulf of Mexico. In 1997, we began spending more money in these areas, contributing to the increase over 1996.

Other Factors

Our production costs per barrel have increased over the last two years. This increase is due to higher depreciation expenses and production costs associated with the acquired Monterey properties. However, applying our enhanced oil recovery techniques to the acquired Monterey fields has reduced cash lifting costs for these properties by over $1 per barrel.

U.S. PRODUCTION COSTS PER BARREL
(Dollars)



Slight rise due to higher lifting costs of acquired Monterey properties.

Special Items

Results for 1998 included asset write-downs of $51 million for impaired properties in Louisiana and Canada and $29 million for employee separation costs.

The employee separation costs result from our announced worldwide restructuring which should be completed by the end of the first quarter of 1999. This restructuring is expected to yield significant annual cost savings.

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, a gain of $26 million from the sale of gas properties in Canada and a $43 million charge for expense accruals associated with royalty and tax issues.

International Upstream

(Millions of dollars, except as indicated)	1998	1997	1996
Operating income before special items	$ 172	$ 474	$ 466
Special items:			
Asset write-downs	(42)	(10)	—
Employee separation costs	(10)	—	—
Gains on major asset sales	—	328	—
Tax and other issues	—	15	27
Total special items	(52)	333	27
Operating income	$ 120	$ 807	$ 493
Selected Operating Data:			
Net production			
Crude oil and NGL (thousands of barrels a day)	497	437	399
Natural gas available for sale (millions of cubic feet a day)	548	471	382
Average realized crude price (dollars per barrel)	$ 11.20	$ 17.64	$ 19.55
Average realized natural gas price (dollars per MCF)	$ 1.62	$ 1.66	$ 1.79
Exploratory expenses (millions of dollars)	$ 204	$ 282	$ 226
Production costs (dollars per barrel)	$ 3.74	$ 4.30	$ 4.47
Return on average capital employed before special items	5.5%	17.9%	19.1%
Return on average capital employed	3.9%	30.5%	20.2%

WHAT HAPPENED IN THE INTERNATIONAL AREAS?

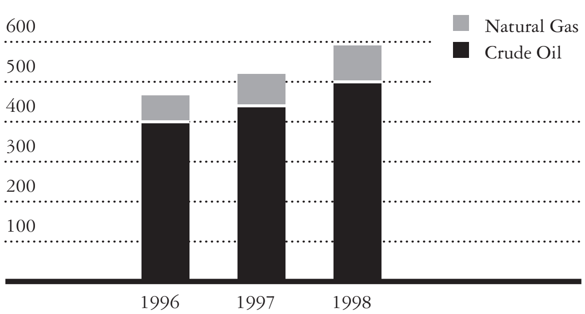
Business Factors

PRICES Lower prices reduced 1998 earnings by $503 million. Our average realized crude oil price decreased 37% to $11.20 per barrel. This follows a 10% decrease in 1997. This trend of lower 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 decreased 2% in 1998 to $1.62 per MCF. This follows a 7% decrease in 1997.

PRODUCTION Our production had double-digit growth over the last two years. The 1998 increase is attributable 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. Combined production from these fields averaged 78 thousand barrels-of-oil-equivalent per day in 1998. Production also grew in the Partitioned Neutral Zone and Indonesia. Our natural gas production at the Dolphin field in Trinidad and from the Chuchupa field offshore Colombia also contributed to our production growth over the last two years.

Our 1998 production increased 14% following an 11% increase in 1997.

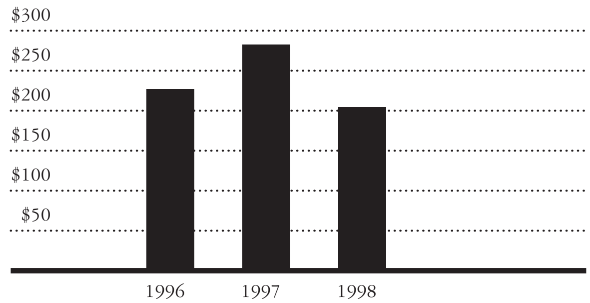
INTERNATIONAL PRODUCTION
(Thousands of barrels of oil equivalent a day)



Production grew by 14% in 1998 due to continuing development in the North Sea, Indonesia and the Middle East.

EXPLORATORY EXPENSES We expensed $204 million on exploration activity in 1998, a decrease of 28%. During the last half of 1998 we slowed activities in the Far East. However, we continued our initiatives to increase future production as we focused on new prospects in the U.K. North Sea and West Africa.

INTERNATIONAL EXPLORATORY EXPENSES
(Millions of dollars)



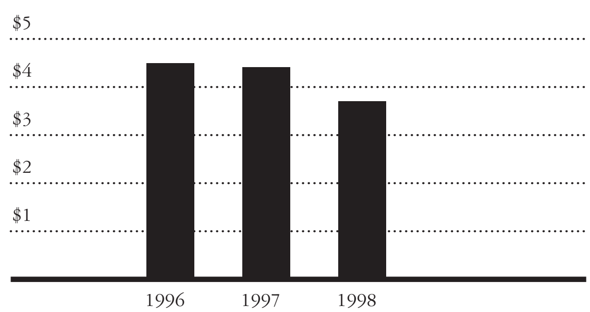
Reduction in 1998 spending due to low-price environment.

Other Factors

Our production costs per barrel for 1998 were $3.74, down 13%. As we raised production and maintained control of expenses, our costs per barrel decreased.

Operating results included non-cash currency translation effects. Years 1998 and 1996 included charges of $2 million and $38 million while 1997 included a benefit of $21 million. These effects are derived from our British pound deferred income tax liability. When the pound strengthens against the U.S. dollar, we recognize a charge and when the pound weakens we experience a benefit.

INTERNATIONAL PRODUCTION COSTS PER BARREL
(Dollars)



Lower lifting costs per barrel through operating efficiencies and increased production.

Special Items

Results for 1998 included a write-down of $42 million for the impairment of our investment in the Strathspey field in the U.K. North Sea and employee separation costs of $10 million from an announced restructuring which is expected to yield annual cost savings.

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. Results for 1996 included a non-cash gain of $27 million for a Danish deferred tax benefit.

LOOKING FORWARD IN THE WORLDWIDE UPSTREAM

We will continue to cost-effectively explore for, develop and produce crude oil and natural gas reserves. Our areas of focus include:

- The Gulf of Mexico where we hold a significant inventory of valuable exploration and development acreage
- Areas rich in heavy oil reserves, where we will apply our world class enhanced oil recovery techniques
- In the U.K. North Sea, where several fields are slated to phase in production in the years 1999 – 2001
- In Kazakhstan, where we have a 20% interest in the Karachaganak oil and gas field
- In West Africa, where we recently announced a major oil discovery offshore Nigeria, and in Latin America

We expect $200 million in annual pre-tax cost savings from our recent upstream restructuring.

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 operations in the Equilon area and the Motiva area. The Equilon area includes western and midwestern refining and marketing operations, and nationwide trading, transportation and lubricants activities. Our 1998 results in this area are our share of the earnings of our joint venture with Shell, named Equilon, which began operations on January 1, 1998. We have a 44% interest in Equilon. Results for 1997 and 1996 are for our subsidiary operations in this same area. The Motiva area includes eastern and Gulf Coast refining and marketing operations. Our 1998 results are, for the last half of the year, our share of the earnings of our joint venture with Shell and Saudi Refining, Inc., named 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 years 1997 and 1996 are for our share of our joint venture with Saudi Refining, Inc., named Star. We had a 50% interest in Star.

Internationally, our downstream operations are reported separately as Latin America and West Africa and Europe. We also have a 50% joint venture with Chevron named 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 and other refined product trading activity.

We will present our U.S. and international results and conclude our discussion with some forward-looking comments.

United States Downstream

(Millions of dollars, except as indicated)	1998	1997	1996
Operating income before special items	$ 278	$ 311	$ 236
Special items:			
Inventory valuation adjustments	(34)	—	—
Employee separation costs	—	—	(1)
U.S. joint venture formation issues	(21)	—	—
Gains (losses) on major asset sales	—	13	(25)
Total special items	(55)	13	(26)
Operating income	$ 223	$ 324	$ 210
Selected Operating Data:			
Refinery input (thousands of barrels a day)	698	747	724
Refined product sales (thousands of barrels a day)	1,203	1,022	1,036
Return on average capital employed before special items	9.6%	9.8%	7.4%
Return on average capital employed	7.7%	10.2%	6.6%

WHAT HAPPENED IN THE UNITED STATES?

Equilon Area These operations contributed 79% of our 1998 operating income before special items. 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 includes a 4% growth in Texaco branded gasoline sales. We achieved higher results for 1997 from improved refining margins, better run-rates at our refineries and effective cost cutting. In 1996, increased crude oil costs late in the year sent margins downward from a second quarter peak.

Motiva Area These operations contributed 21% of our 1998 operating income before special items. The 1998 earnings were lower due to refinery downtime coupled with lower refining margins. Refined product sales were higher as a result of our new joint venture and an increase in Texaco branded gasoline sales of 2%. The year 1997 benefited from improved Gulf Coast refining margins while 1996 earnings were adversely affected by refinery disruptions that lowered yields.

Special Items Results for 1998 included a charge for inventory valuation adjustments of $34 million to reflect lower market prices for crude oil and refined products and a net charge of $21 million for U.S. alliance formation issues. This net charge includes charges of $52 million for employee separations and $45 million for asset write-downs of closed facilities and surplus equipment and other expenses. Also included in other net charges were gains of $76 million for the Federal Trade Commission-mandated sales of the Anacortes refinery and Plantation pipeline. Results for 1997 included a gain of $13 million from the sale of our credit card business. Results for 1996 included charges of $26 million primarily related to the sale of a propylene oxide/methyl tertiary butyl ether (PO/MTBE) manufacturing site in Texas.

International Downstream

(Millions of dollars, except as indicated)	1998	1997	1996
Operating income before special items	**$ 503**	$ 524	$ 249
Special items:			
Inventory valuation adjustments	**(108)**	—	—
Employee separation costs	**(20)**	—	(21)
Caltex reorganization	**(43)**	—	—
Gains on major asset sales	—	—	219
Tax and other issues	—	(16)	—
Total special items	**(171)**	(16)	198
Operating income	**$ 332**	$ 508	$ 447
Selected Operating Data:			
Refinery input (thousands of barrels a day)	**832**	804	762
Refined product sales (thousands of barrels a day)	**1,685**	1,563	1,552
Return on average capital employed before special items	**8.1%**	8.9%	4.5%
Return on average capital employed	**5.3%**	8.7%	8.0%

WHAT HAPPENED IN THE INTERNATIONAL AREAS?

Latin America and West Africa Our operations in Latin America and West Africa contributed 63% of 1998 operating income before special items. Refined product sales volumes increased due to service station acquisitions and the expansion of our industrial customer base. We also realized improved refinery operations in Panama. In 1997, earnings increased due to higher refining margins and a growth in product sales volumes.

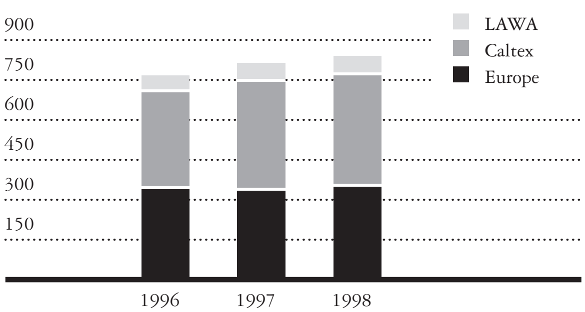
Europe Our European operations contributed 25% of 1998 operating income before special items. Earnings increased significantly from improved refining and marketing margins. Additionally, we grew our refined product sales volumes by increasing retail outlets and obtaining new commercial business. In 1997, earnings increased as general industry conditions improved from the historically low levels experienced in 1996.

Results for 1998 and 1996 included non-cash currency charges of $3 million and $20 million related to deferred income taxes that are denominated in British pounds while 1997 had a $7 million benefit.

Caltex Our Caltex operations contributed 9% of 1998 operating income before special items. In 1998, our share of Caltex' results was $163 million lower. The dramatic earnings decline was due to currency-related losses in 1998 versus gains in 1997. The year-to-year earnings decline due to currency effects was $204 million. Excluding currency effects, Caltex' results in 1998 improved as both margins and volumes were higher. This improvement was accomplished in spite of the economic downturn experienced by many Asian economies. Our share of Caltex' results in 1997, excluding currency-related gains of $101 million, was basically unchanged from 1996. Strong operational results in the first nine months of 1997 eroded in the fourth quarter due to the economic crisis in Southeast Asia.

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 REFINERY INPUT
(Thousands of barrels a day)



Texaco's refinery system supplies key markets.

Special Items Results for 1998 included a charge for inventory valuation adjustments of $108 million to reflect lower market prices for crude oil and refined products, employee separation costs of $20 million associated with various cost-cutting initiatives, mostly in the U.K., Panama and Brazil, and a charge of $43 million for a reorganization program in Caltex.

The Caltex charge results 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 will relocate its headquarters from Dallas to Singapore. About $35 million of the 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.

Results for 1997 included a charge of $16 million primarily for a European deferred tax adjustment. Results for 1996 included a charge for employee separations of $21 million and a gain of $219 million related to the sale of Caltex' interest in Nippon Petroleum Refining Company, Limited.

LOOKING FORWARD IN THE WORLDWIDE DOWNSTREAM

We anticipate that our joint ventures with Shell and Saudi Refining, Inc. will continue to lower costs and capture synergies. Our share of these annual pre-tax cost reductions is expected to be over $300 million. We will continue to expand in Latin America. In addition, our share of the annual pre-tax cost savings from the Caltex reorganization is expected to be $25 million.

Global Gas Marketing

(Millions of dollars, except as indicated)	1998	1997	1996
Operating income (loss) before special items	**$ (35)**	$ (43)	$ 34
Special items:			
Employee separation costs	**(3)**	—	—
Gain on major asset sales	**20**	—	—
Total special items	**17**	—	—
Operating income (loss)	**$ (18)**	$ (43)	$ 34
Natural gas sales (millions of cubic feet per day)	**3,764**	3,452	2,937

Global gas marketing purchases natural gas and natural gas products from our upstream operations and others for resale, and operates natural gas processing plants and pipelines in the United States.

Our global gas marketing results in both 1998 and 1997 were adversely affected by losses associated with our start-up wholesale and retail marketing activities in the United Kingdom. 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. In 1996, natural gas marketing margins in the U.S. were strong, especially in the first quarter.

Special Items Results for 1998 included employee separation costs of $3 million associated with an announced restructuring and a gain of $20 million on the sale of an interest in our Discovery pipeline affiliate. The restructuring is expected to yield annual pre-tax cost savings of $20 million.

LOOKING FORWARD IN GLOBAL GAS MARKETING
Operations will focus on more profitable trading markets. We will also exit the retail gas marketing business in the United Kingdom.

Other Business Units

(Millions of dollars)	1998	1997	1996
Operating income	$ 7	$ 5	$ 10

Our other business units include insurance activity and power generation and gasification operations. There were no significant items in our three-year results.

Corporate/Non-operating

(Millions of dollars)	1998	1997	1996
Results before special items	$ (412)	$ (415)	$ (404)
Special items:			
Employee separation costs	(18)	—	(43)
Tax benefits on asset sales	43	—	188
Tax and other issues	25	488	9
Total special items	50	488	154
Total Corporate/ Non-operating	$ (362)	$ 73	$ (250)

Corporate/Non-operating includes our corporate center and financing activities. Over the last three years, our corporate and non-operating results before special items have been relatively flat. The year 1998 includes lower overhead and tax expense as well as higher interest income mostly offset by interest expense from higher average debt levels.

Special Items Results for 1998 included a charge of $18 million for employee separation costs associated with our corporate center reorganization and other cost-cutting initiatives which are expected to reduce annual pre-tax costs by $60 million. Also included in 1998 results are tax benefits of $43 million for the sales of interests in a subsidiary and a benefit of $25 million to adjust for prior years' federal tax liabilities. The year 1997 included a tax benefit of $488 million for an IRS settlement. Results for 1996 included a charge of $43 million for employee separation costs, a tax benefit of $188 million from the sale of an interest in a subsidiary, a tax benefit of $41 million from adjusting prior years' state tax expenses, and a charge of $32 million for expense accruals for litigation issues.

Other Items

Liquidity and Capital Resources

INTRODUCTION The Statement of Consolidated Cash Flows on page 45 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-requirement strategy is to rely on 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 an investing activity. In 1998, cash from operating activities of $2,544 million is significantly lower than the prior year primarily due to lower prices. For more detailed insight into our financial and operational results, see Analysis of Income by Operating Segments on the preceding pages.

Net new borrowings in 1998 were $1,052 million compared to $498 million in 1997. Our strong cash management policies have provided us with the resources to obtain cash necessary to supplement our funding requirements when faced with deteriorating market conditions such as lower crude oil and natural gas prices. During the year, we borrowed $280 million associated with assets in the U.K. North Sea, $691 million from our existing "shelf" registrations, including $191 million under our medium-term note program, and $94 million from the issuance of Zero Coupon Notes in Brazil. We also increased the amount of our commercial paper by $725 million during the year, to a total of $1.6 billion at year-end. See Note 10 to the financial statements for total outstanding debt, including 1998 borrowings.

After December 31, 1998, we issued an additional $500 million from our existing "shelf" registration to refinance existing short-term debt.

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 additional support for liquidity and our commercial paper program.

Cash from affiliates of $612 million was received from Equilon, representing formation payments. In February 1999, we received $101 million from Equilon for the payment of notes receivable.

OUTFLOWS *Capital and exploratory expenditures (Capex)* were $3,101 million in 1998 — The section on page 37 describes in more detail the uses of our Capex dollars.

We continue our commitment to return value to our shareholders through a sustained dividend policy.

Payments of dividends were $1,057 million in 1998 — $952 million to common, $53 million to preferred and $52 million to shareholders who hold a minority interest in Texaco subsidiary companies.

Purchases of common stock were $579 million in 1998 — In the first quarter of 1998, we purchased $105 million of our common stock. In March 1998, we announced our intention to purchase up to an additional $1 billion of our common stock, subject to market conditions, through open market purchases or privately negotiated transactions. Under this program, we purchased $474 million in the second and third quarters of 1998. Purchases under this program have been suspended for an indefinite period.

The following table reflects our key financial indicators:

(Millions of dollars, except as indicated)	1998	1997	1996
Current ratio	**1.07**	1.07	1.24
Total debt	**$ 7,291**	$ 6,392	$ 5,590
Average years debt maturity	**10**	11	12
Average interest rates	**7.0%**	7.2%	7.5%
Minority interest in subsidiary companies	**$ 679**	$ 645	$ 658
Stockholders' equity	**$ 11,833**	$ 12,766	$ 10,372
Total debt to total borrowed and invested capital	**36.8%**	32.3%	33.6%

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 while assuring that the appropriate safeguards are in effect to provide adequate internal controls for all transactions. Cash required to service debt maturities in 1999 is projected to be about $500 million, which we intend to refinance.

While projections for a low price scenario extend through 1999, we feel that our *cash from operating activities,* coupled with our *borrowing* capacity, will allow us to meet our *Capex* requirements and continue to provide substantial return to our shareholders in the form of dividends.

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

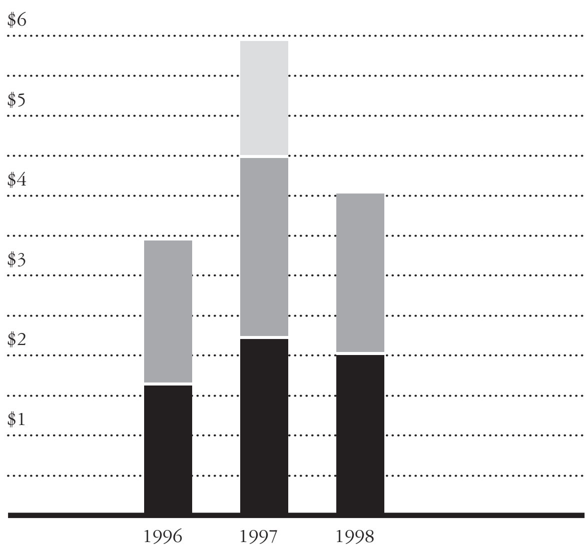
- The price of crude oil, natural gas and petroleum products
- The value of foreign currencies in relation to the U.S. dollar
- Interest rates

We enter into arrangements such as futures contracts, swaps and options to manage our exposure to these risks within established guidelines. Our written policies for engaging in these transactions limit our exposure and do not allow for speculation. These arrangements do not expose us to material adverse effects. See Notes 10, 15 and 16 to the financial statements and Supplemental Market Risk Disclosures on page 76 for additional information.

Capital and Exploratory Expenditures

1998 ACTIVITY Worldwide capital and exploratory expenditures, including our share of affiliates, were $4.0 billion for the year 1998, $5.9 billion for 1997 and $3.4 billion in 1996. The year 1997 included the $1.4 billion acquisition of Monterey Resources Inc., a producing company primarily in California. Excluding this acquisition, Texaco's expenditures in 1998 reflect the deferral of certain projects due to the low-price environment. Expenditures were geographically and functionally split as follows:

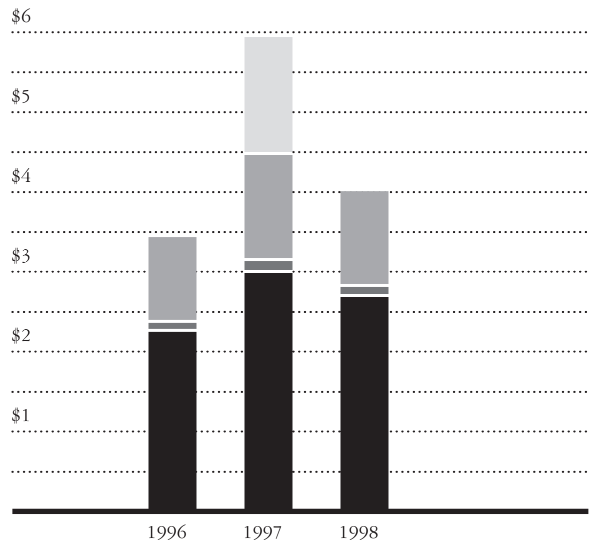
CAPITAL AND EXPLORATORY EXPENDITURES — GEOGRAPHICAL
(Billions of dollars)



Acquisition of Monterey Resources
International
United States

Balanced spending on a worldwide portfolio of projects.

CAPITAL AND EXPLORATORY EXPENDITURES — FUNCTIONAL
(Billions of dollars)



Acquisition of Monterey Resources
Manufacturing, marketing, distribution and other
Global gas marketing
Exploration and production

Continued emphasis on exploration and production projects.

EXPLORATION AND PRODUCTION Significant areas of investment included:

- High-impact development and exploratory projects in the deepwater Gulf of Mexico
- Enhanced oil recovery spending in California and Indonesia
- Exploratory activity in promising international areas, including Nigeria, the U.K., Angola and Trinidad
- Development work in the U.K. North Sea, Indonesia and other promising areas
- Continued investments, though at a slowed pace, in Eurasia

MANUFACTURING, MARKETING AND DISTRIBUTION AND OTHER
Investments in downstream facilities included:

- Refining and marketing investments by two newly formed alliances in the United States
- Marketing expansion throughout promising areas of Latin America
- Investments associated with the Caltex refinery in Thailand

The following table details our capital and exploratory expenditures:

(Millions of dollars)	1998 U.S.	1998 International	1998 Total	1997 U.S.	1997 International	1997 Total	1996 U.S.	1996 International	1996 Total
Exploration and production									
Exploratory expenses	$ 257	$ 204	$ 461	$ 189	$ 282	$ 471	$ 153	$ 226	$ 379
Capital expenditures									
Acquisition of Monterey Resources Inc.	—	—	—	1,448	—	1,448	—	—	—
Other	1,182	1,068	2,250	1,406	1,127	2,533	990	902	1,892
Total exploration and production	1,439	1,272	2,711	3,043	1,409	4,452	1,143	1,128	2,271
Manufacturing, marketing and distribution	433	726	1,159	429	848	1,277	357	658	1,015
Global gas marketing	115	—	115	142	2	144	103	7	110
Other	33	1	34	55	2	57	33	2	35
Total	$ 2,020	$ 1,999	$ 4,019	$ 3,669	$ 2,261	$ 5,930	$ 1,636	$ 1,795	$ 3,431
Total, excluding affiliates	$ 1,528	$ 1,496	$ 3,024	$ 3,421	$ 1,718	$ 5,139	$ 1,535	$ 1,338	$ 2,873

1999 AND BEYOND Spending for 1999 is expected to be $3.7 billion. We realize that future profitability is in large part dependent upon successful investments today. Even in the current low-price environment, we feel it is important to continue to prudently allocate capital resources on projects which often have long lead times and which will generate attractive returns in the future.

In the upstream, development spending will be directed toward projects in the U.S. deepwater Gulf of Mexico, the U.K. North Sea and Denmark. Major exploration projects will include Nigeria, Angola and Trinidad. In the downstream, capital requirements funded by our affiliates Equilon, Motiva and Caltex, will be slightly lower in 1999. In the European and Latin American downstream areas, 80% of the expenditures relate to marketing operations. Most of the manufacturing capital will be spent at the Pembroke plant in the U.K. We will also increase our capital spending for power generation projects, mostly through affiliates.

Environmental Matters

The cost of compliance with federal, state and local environmental laws in both the U.S. and international continues to be substantial. Using definitions and guidelines established by the American Petroleum Institute, our 1998 environmental spending was $807 million. This includes our equity share in the environmental expenditures of our major affiliates, Equilon, Motiva and its predecessor Star, and the Caltex Group of Companies. The following table provides our environmental expenditures for the past three years:

(Millions of dollars)	1998	1997	1996
Capital expenditures	$ 175	$ 162	$ 185
Non-capital:			
Ongoing operations	495	538	561
Remediation	93	79	111
Restoration and abandonment	44	46	48
Total environmental expenditures	$ 807	$ 825	$ 905

CAPITAL EXPENDITURES

Our spending for capital projects in 1998 was $175 million. These expenditures were made to comply with clean air and water regulations as well as waste management requirements. In the United States, reformulated gasoline must meet more stringent emission requirements in the year 2000. As a result, additional investments will be made to meet these new standards. Worldwide capital expenditures projected for 1999 and 2000 are $194 million and $183 million.

ONGOING OPERATIONS

In 1998, environmental expenses charged to current operations were $495 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 1998 were $93 million. This included $14 million spent on the remediation of Superfund waste sites. At the end of 1998, we had liabilities of $468 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 hazardous waste sites. We have determined that we may have potential exposure, though limited in most cases, at 260 multi-party hazardous waste sites. Of these sites, 73 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 PRP's. 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 1998 for restoration and abandonment amounted to $44 million. At year-end 1998, accruals to cover the cost of restoration and abandonment or "closure" of our oil and gas producing properties were $851 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 will be material to our financial position or to our operating results over any reasonable period of time.

New Accounting Standards

Note 2 to the financial statements discusses accounting standards adopted in 1998.

In June 1998, SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," was issued. SFAS 133 establishes new accounting rules and disclosure requirements for most derivative instruments and for hedging related to those instruments. We will adopt this Statement effective January 1, 2000 and are currently assessing the initial 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 legacy currencies and one common currency — the euro. The euro began trading on world currency exchanges 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.

Our operating subsidiaries affected by the euro conversion have been actively addressing our computer systems and overall fiscal and operational activities to ensure our euro readiness. We are adapting our computer, financial and operating systems and equipment to accommodate euro-denominated transactions. We are also reviewing 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

THE PROBLEM The Year 2000 (Y2K) problem concerns the inability of information and technology based operating systems to properly recognize and process date-sensitive information beyond December 31, 1999. This could result in systems failures and miscalculations, which could cause business disruptions. Equipment that uses a date, such as computers and operating control systems, may be affected. This includes equipment used by our customers and suppliers, as well as by utilities and governmental entities that provide critical services to us.

OUR STATE OF READINESS We started working on the Y2K problem in early 1995. By early 1996, we formed a Business Unit Steering Team and a Corporate Year 2000 Office. Our progress is reported monthly to our Chief Executive Officer, and quarterly to our Board of Directors. Additionally, we are actively performing both internal audits and external reviews to ensure that we reach our objectives.

We recognize that the Y2K issue affects every aspect of our business, including computer software, computer hardware, telecommunications, industrial automation and relationships with our suppliers and customers. Our Y2K effort has included an extensive program to educate our employees, and development of detailed guidelines for project management, testing and remediation. Each business unit is periodically graded on their progress toward reaching their project milestones. Our major affiliates have undertaken similar programs.

In our computers and computer software, most of the problems we have found involve our corporate financial software applications. Approximately 95% of these need some type of modification or upgrade. In our industrial automation systems, which we use in our refinery, lubricant plant, gas plant and oil well operations to monitor, control and log data about the processes, approximately 5% need modification or upgrade. The majority of these are auxiliary systems, such as laboratory analyzers and alarm logging functions, but several of the higher level supervisory data acquisition systems and flow metering systems also require upgrades.

At the end of 1998, we were approximately 80% through our Y2K efforts of inventorying, assessing and fixing our systems.

Almost all systems should be ready by the end of the first quarter of 1999, but a few will be delayed until later in 1999 as we wait for vendor upgrades. If any of these late-scheduled upgrades are delayed, we will seek alternate vendors or develop contingency plans, as appropriate. We are also progressing in our reviews with critical suppliers and customers as to their Y2K state of readiness.

COSTS Because we began early, we have been able to do most of the work ourselves. This has kept our costs low, and we project that we will spend no more than $75 million on making our systems Y2K ready. As of December 31, 1998, we have incurred costs of approximately $37 million.

RISKS Certain Y2K risk factors which could have a material adverse effect on our results of operations, liquidity and financial condition include, but are not limited to: failure to identify critical systems which will experience failures, errors in efforts to correct problems, unexpected failures by key business suppliers and customers, extended failures by public and private utility companies or common carriers supplying services to us and failures in global banking systems and capital markets.

If we have missed a potential Y2K problem, it will most likely be in our financial software, or in auxiliary systems in our operations, such as laboratory analyzers and alarm logging functions, where we have found the majority of the problems. We do not anticipate that a problem in these areas will have a significant impact on our ability to pursue our primary business objectives. We routinely analyze all of our production and automation systems for potential failures and appropriate responses are identified and documented. Any problems in our primary industrial automation systems can be dealt with using our existing engineering procedures.

The worst case scenario would be that our failure or failures by our important suppliers and customers to correct material Y2K problems could result in serious disruptions in normal business activities and operations. Such disruptions could prevent us from producing crude oil and natural gas, and manufacturing and delivering refined products to customers. For example, failure by a utility company to deliver electricity to our producing operations could cause us to shut-in production leading to lost sales and income. We do not expect a worst case scenario. However, if it occurs, Y2K failures, if not corrected on a timely basis or otherwise mitigated by our contingency plans, could have a material adverse effect on our results of operations, liquidity and overall financial condition.

CONTINGENCY PLANS We are well into our program to identify and assess our Y2K readiness and the Y2K readiness of our critical and important suppliers and customers. We will either seek alternative suppliers and customers for those we assess as risky, or we will develop and test contingency plans. We have begun to develop these contingency plans. In addition, we are reviewing our existing business resumption plans. We expect to arrange alternative suppliers or develop and complete the testing of contingency plans no later than July 1, 1999.

Description of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements consist of the accounts of Texaco Inc. and subsidiary companies owned directly or indirectly more than 50% except when voting control does not exist. 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, we are required to use estimates and management's 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 the passage of title during delivery.

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 initial 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 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 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 nonproductive. 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 nonmineral 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 expense environmentally-related remediation costs and record them as liabilities. 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, nonproductive 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	1998	1997	1996
Revenues			
Sales and services (includes transactions with significant affiliates of $4,169 million in 1998, $3,633 million in 1997 and $3,867 million in 1996)	$ 30,910	$ 45,187	$ 44,561
Equity in income of affiliates, interest, asset sales and other	797	1,480	939
Total revenues	31,707	46,667	45,500
Deductions			
Purchases and other costs (includes transactions with significant affiliates of $1,669 million in 1998, $2,178 million in 1997 and $2,048 million in 1996)	24,179	35,230	34,643
Operating expenses	2,508	3,251	3,235
Selling, general and administrative expenses	1,224	1,755	1,803
Exploratory expenses	461	471	379
Depreciation, depletion and amortization	1,675	1,633	1,455
Interest expense	480	412	434
Taxes other than income taxes	423	520	496
Minority interest	56	68	72
	31,006	43,340	42,517
Income before income taxes and cumulative effect of accounting change	701	3,327	2,983
Provision for income taxes	98	663	965
Income before cumulative effect of accounting change	603	2,664	2,018
Cumulative effect of accounting change	(25)	—	—
Net income	$ 578	$ 2,664	$ 2,018
Net Income per Common Share (Dollars)			
Basic:			
Income before cumulative effect of accounting change	$ 1.04	$ 4.99	$ 3.77
Cumulative effect of accounting change	(.05)	—	—
Net income	$ .99	$ 4.99	$ 3.77
Diluted:			
Income before cumulative effect of accounting change	$ 1.04	$ 4.87	$ 3.68
Cumulative effect of accounting change	(.05)	—	—
Net income	$ .99	$ 4.87	$ 3.68
Average Number of Common Shares Outstanding (for computation of earnings per share) (thousands)			
Basic	528,416	522,234	520,392
Diluted	528,965	542,570	541,824

See accompanying notes to consolidated financial statements.

Consolidated Balance Sheet

(Millions of dollars) As of December 31	1998	1997
Assets		
Current Assets		
Cash and cash equivalents	$ 249	$ 311
Short-term investments – at fair value	22	84
Accounts and notes receivable (includes receivables from significant affiliates of $694 million in 1998 and $234 million in 1997), less allowance for doubtful accounts of $28 million in 1998 and $22 million in 1997	3,955	4,230
Inventories	1,154	1,483
Deferred income taxes and other current assets	256	324
Total current assets	5,636	6,432
Investments and advances	7,184	5,097
Net properties, plant and equipment	14,761	17,116
Deferred charges	989	955
Total	$ 28,570	$ 29,600
Liabilities and Stockholders' Equity		
Current Liabilities		
Notes payable, commercial paper and current portion of long-term debt	$ 939	$ 885
Accounts payable and accrued liabilities (includes payables to significant affiliates of $395 million in 1998 and $106 million in 1997)		
Trade liabilities	2,302	2,669
Accrued liabilities	1,368	1,480
Estimated income and other taxes	655	960
Total current liabilities	5,264	5,994
Long-term debt and capital lease obligations	6,352	5,507
Deferred income taxes	1,644	1,825
Employee retirement benefits	1,248	1,224
Deferred credits and other noncurrent liabilities	1,550	1,639
Minority interest in subsidiary companies	679	645
Total	16,737	16,834
Stockholders' Equity		
Market auction preferred shares	300	300
ESOP convertible preferred stock	428	457
Unearned employee compensation and benefit plan trust	(334)	(389)
Common stock – 567,606,290 shares issued	1,774	1,774
Paid-in capital in excess of par value	1,640	1,688
Retained earnings	9,561	9,987
Other accumulated nonowner changes in equity	(101)	(95)
	13,268	13,722
Less – Common stock held in treasury, at cost	1,435	956
Total stockholders' equity	11,833	12,766
Total	$ 28,570	$ 29,600

See accompanying notes to consolidated financial statements.

Statement of Consolidated Cash Flows

(Millions of dollars) For the years ended December 31	1998	1997	1996
Operating Activities			
Net income	$ 578	$ 2,664	$ 2,018
Reconciliation to net cash provided by (used in) operating activities			
Cumulative effect of accounting change	25	—	—
Depreciation, depletion and amortization	1,675	1,633	1,455
Deferred income taxes	(152)	451	(20)
Exploratory expenses	461	471	379
Minority interest in net income	56	68	72
Dividends from affiliates, greater than (less than) equity in income	224	(370)	167
Gains on asset sales	(109)	(558)	(19)
Changes in operating working capital			
Accounts and notes receivable	125	718	(1,072)
Inventories	(51)	(56)	(104)
Accounts payable and accrued liabilities	16	(856)	716
Other – mainly estimated income and other taxes	(205)	(64)	97
Other – net	(99)	(186)	73
Net cash provided by operating activities	2,544	3,915	3,762
Investing Activities			
Capital and exploratory expenditures	(3,101)	(3,628)	(2,897)
Proceeds from asset sales	282	1,036	125
Proceeds from sale of discontinued operations	—	—	344
Sales (purchases) of leasehold interests	25	(503)	261
Purchases of investment instruments	(947)	(1,102)	(1,668)
Sales/maturities of investment instruments	1,118	1,096	1,816
Formation payments from U.S. affiliate	612	—	—
Other – net	—	(57)	70
Net cash used in investing activities	(2,011)	(3,158)	(1,949)
Financing Activities			
Borrowings having original terms in excess of three months			
Proceeds	1,300	507	307
Repayments	(741)	(637)	(802)
Net increase (decrease) in other borrowings	493	628	(143)
Purchases of common stock	(579)	(382)	(159)
Dividends paid to the company's stockholders			
Common	(952)	(918)	(859)
Preferred	(53)	(55)	(58)
Dividends paid to minority stockholders	(52)	(81)	(87)
Net cash used in financing activities	(584)	(938)	(1,801)
Cash and Cash Equivalents			
Effect of exchange rate changes	(11)	(19)	(2)
Increase (decrease) during year	(62)	(200)	10
Beginning of year	311	511	501
End of year	$ 249	$ 311	$ 511

See accompanying notes to consolidated financial statements.

Statement of Consolidated Stockholders' Equity

(Shares in thousands; amounts in millions of dollars)	Shares 1998	Amount 1998	Shares 1997	Amount 1997	Shares 1996	Amount 1996
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 – liquidation value of $600 per share						
Beginning of year	693	416	720	432	751	450
Retirements	(44)	(27)	(27)	(16)	(31)	(18)
End of year	649	389	693	416	720	432
Series F ESOP Convertible Preferred Stock – liquidation value of $737.50 per share						
Beginning of year	56	41	57	42	60	45
Retirements	(3)	(2)	(1)	(1)	(3)	(3)
End of year	53	39	56	41	57	42
Unearned Employee Compensation						
(related to ESOP preferred stock and restricted stock awards)						
Beginning of year		(149)		(175)		(234)
Awards		(36)		(16)		(22)
Amortization and other		91		42		81
End of year		(94)		(149)		(175)
Benefit Plan Trust						
(common stock)						
Beginning of year	9,200	(240)	8,000	(203)	8,000	(203)
Additions	—	—	1,200	(37)	—	—
End of year	9,200	(240)	9,200	(240)	8,000	(203)
Common Stock						
par value $3.125; Shares authorized – 700,000,000						
Beginning of year	567,606	1,774	548,587	1,714	548,587	1,714
Issued for Monterey acquisition	—	—	19,019	60	—	—
End of year	567,606	1,774	567,606	1,774	548,587	1,714
Common Stock Held in Treasury, at cost						
Beginning of year	25,467	(956)	21,191	(628)	20,152	(517)
Purchases of common stock	9,572	(551)	7,423	(410)	3,515	(159)
Transfer to benefit plan trust	—	—	(1,200)	37	—	—
Other – mainly employee benefit plans	(2,063)	72	(1,947)	45	(2,476)	48
End of year	32,976	$ (1,435)	25,467	$ (956)	21,191	$ (628)

See accompanying notes to consolidated financial statements.

(Continued on next page)

Statement of Consolidated Stockholders' Equity

(Millions of dollars)	1998	1997	1996
Paid-in Capital in Excess of Par Value			
Beginning of year	$ 1,688	$ 630	$ 655
Monterey acquisition	—	1,091	—
Treasury stock transactions relating to investor services plan and employee compensation plans	(48)	(33)	(25)
End of year	1,640	1,688	630
Retained Earnings			
Balance at beginning of year	9,987	8,292	7,186
Add:			
Net income	578	2,664	2,018
Tax benefit associated with dividends on unallocated ESOP Convertible Preferred Stock	3	4	5
Deduct: Dividends declared on			
Common stock ($1.80 per share in 1998, $1.75 per share in 1997 and $1.65 per share in 1996)	952	918	859
Preferred stock			
Series B ESOP Convertible Preferred Stock	38	40	42
Series F ESOP Convertible Preferred Stock	4	4	4
Market Auction Preferred Shares (Series G, H, I and J)	13	11	12
Balance at end of year	9,561	9,987	8,292
Other Accumulated Nonowner Changes in Equity			
Currency translation adjustment			
Beginning of year	(105)	(65)	61
Change during year	(2)	(40)	(126)
End of year	(107)	(105)	(65)
Minimum pension liability adjustment			
Beginning of year	(16)	—	—
Change during year	(8)	(16)	—
End of year	(24)	(16)	—
Unrealized net gain on investments			
Beginning of year	26	33	62
Change during year	4	(7)	(29)
End of year	30	26	33
Total other accumulated nonowner changes in equity	(101)	(95)	(32)
Stockholders' Equity			
End of year (including preceding page)	$11,833	$12,766	$10,372

See accompanying notes to consolidated financial statements.

Statement of Consolidated Nonowner Changes in Equity

(Millions of dollars)	1998	1997	1996
Net income	$ 578	$ 2,664	$ 2,018
Other nonowner changes in equity:			
Currency translation adjustment			
Reclassification to net income of realized gain on sale of affiliate	—	—	(60)
Other unrealized net change during period	(2)	(40)	(66)
Total	(2)	(40)	(126)
Minimum pension liability adjustment			
Before income taxes	(16)	(21)	—
Income taxes	8	5	—
Total	(8)	(16)	—
Unrealized net gain on investments			
Net gain (loss) arising during period			
Before income taxes	35	22	9
Income taxes	(11)	(9)	(7)
Reclassification to net income of net realized (gain) or loss			
Before income taxes	(31)	(29)	(43)
Income taxes	11	9	12
Total	4	(7)	(29)
Total other nonowner changes in equity	(6)	(63)	(155)
Total nonowner changes in equity	$ 572	$ 2,601	$ 1,863

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 1998, 1997 and 1996, according to Statement of Financial Accounting Standards 131, *Disclosures about Segments of an Enterprise and Related Information*, which we adopted this year.

We determined our operating segments based on differences in the nature of their operations and geographic location. The composition of segments and measure of segment profit is 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 1998

	Sales and Services								
(Millions of dollars)	Outside	Inter-segment	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	$ 1,712	$ 1,660	$ 3,372	$ 301	$ 34	$ 892	$ 1	$ 1,200	$ 8,699
International	2,028	1,358	3,386	120	127	513	20	951	4,352
Manufacturing, marketing and distribution									
United States	2,582	107	2,689	223	96	6	228	1	4,095
International	19,835	86	19,921	332	130	204	135	403	8,306
Global gas marketing	4,692	84	4,776	(18)	5	14	50	61	879
Segment totals	$ 30,849	$ 3,295	34,144	958	392	1,629	434	2,616	26,331
Other business units			91	7	4	2	(2)	—	506
Corporate/Non-operating			4	(362)	(298)	44	(67)	33	1,945
Intersegment eliminations			(3,329)	—	—	—	—	—	(212)
Consolidated, before cumulative effect of accounting change			$ 30,910	$ 603	$ 98	$ 1,675	$ 365	$ 2,649	$ 28,570

Operating Segments 1997

	Sales and Services								
(Millions of dollars)	Outside	Inter-segment	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	$ 4,156	$ 4,521	$ 990	$ 487	$ 783	$ 281	$ 1,349	$ 8,769
International	2,575	1,751	4,326	807	566	442	105	934	4,036
Manufacturing, marketing and distribution									
United States	16,992	357	17,349	324	172	178	169	262	5,668
International	19,992	235	20,227	508	117	173	(166)	482	8,048
Global gas marketing	5,207	254	5,461	(43)	(9)	14	61	75	1,012
Segment totals	$ 45,131	$ 6,753	51,884	2,586	1,333	1,590	450	3,102	27,533
Other business units			101	5	5	2	4	—	544
Corporate/Non-operating			6	73	(675)	41	242	57	2,030
Intersegment eliminations			(6,804)	—	—	—	—	—	(507)
Consolidated			$ 45,187	$ 2,664	$ 663	$ 1,633	$ 696	$ 3,159	$ 29,600

Operating Segments 1996

(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	$ 204	$ 4,146	$ 4,350	$ 1,074	$ 528	$ 670	$ 109	$ 990	$ 6,067
International	2,384	1,930	4,314	493	523	393	(21)	755	3,651
Manufacturing, marketing and distribution									
United States	18,424	493	18,917	210	143	176	92	271	6,310
International	18,750	363	19,113	447	127	161	201	356	7,751
Global gas marketing	4,754	342	5,096	34	19	13	(7)	110	1,152
Segment totals	$ 44,516	$ 7,274	51,790	2,258	1,340	1,413	374	2,482	24,931
Other business units			112	10	10	7	3	—	530
Corporate/Non-operating			5	(250)	(385)	35	332	35	2,216
Intersegment eliminations			(7,346)	—	—	—	—	—	(714)
Consolidated			$ 44,561	$ 2,018	$ 965	$ 1,455	$ 709	$ 2,517	$ 26,963

Our exploration and production segments explore for, find, develop and produce crude oil and natural gas. The U.S. segment includes minor operations in Canada. Our manufacturing, marketing and distribution segments process crude oil and other feedstock into refined products and purchase, sell and transport crude oil and refined petroleum products. Global gas marketing purchases natural gas and natural gas products from our exploration and production operations and others for resale, and operates natural gas processing plants and pipelines in the United States. This segment, which operates primarily in the U.S., sold its U.K. wholesale gas business in 1998 and announced its intention to dispose of its U.K. retail gas marketing business as well. Other business units include our insurance, power generation and gasification 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 6 – *Investments and Advances,* beginning on page 52, 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 1998	Sales and Services 1997	Sales and Services 1996	Long-lived assets at December 31 1998	Long-lived assets at December 31 1997	Long-lived assets at December 31 1996
United States	**$ 8,184**	$ 21,657	$ 22,643	**$ 8,757**	$ 11,437	$ 8,683
International – Total	**22,726**	23,530	21,918	**6,250**	5,876	4,914
Significant countries included above:						
Brazil	**3,175**	3,175	2,670	**301**	266	235
Netherlands	**1,636**	1,901	2,129	**257**	250	212
United Kingdom	**7,529**	6,862	5,846	**2,257**	2,384	1,846

Note 2 Adoption of New Accounting Standards

SFAS 128 and 129 — 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. In 1997, we also adopted SFAS 129, "Disclosure of Information about Capital Structure." Our existing disclosures complied with this standard.

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 will be adopted by Texaco and our other affiliates effective January 1, 1999. We do not expect the effect to be material.

Note 3 Income Per Common Share

Basic net income per common share is based on 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.

In July 1997, the Board of Directors approved a two-for-one split of the company's common stock, effective September 29, 1997. The par value was halved and the number of authorized shares was doubled. We have restated prior years' financial statements and all references to number of shares and per share amounts for the stock split. Also, we have adjusted all agreements that include exchange, conversion or other rights based on the company's common stock for the stock split.

(Millions, except per share amounts)			1998			1997			1996
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	$ 603			$ 2,664			$ 2,018		
Less: Preferred stock dividends	(54)			(56)			(58)		
Income before cumulative effect of accounting change, for basic income per share	$ 549	528.4	$ 1.04	$ 2,608	522.2	$ 4.99	$ 1,960	520.4	$ 3.77
Effect of dilutive securities:									
ESOP Convertible preferred stock	—	—		34	19.3		34	20.0	
Stock options and restricted stock	—	.4		—	.8		—	1.1	
Convertible debentures	1	.2		—	.3		—	.3	
Income before cumulative effect of accounting change, for diluted income per share	$ 550	529.0	$ 1.04	$ 2,642	542.6	$ 4.87	$ 1,994	541.8	$ 3.68

Note 4 Acquisition of Monterey Resources

In November 1997, we acquired all of the outstanding common stock of Monterey Resources (Monterey) in exchange for approximately 19 million shares of our common stock valued at $1.1 billion. We accounted for the transaction as a purchase. The total purchase price was $1.4 billion, including existing Monterey debt of $.3 billion; $2.2 billion was assigned to properties, plant and equipment, and $.7 billion was assigned to deferred income tax liabilities. Monterey was an oil and gas company with mostly crude oil properties in California.

Our financial statements reflect the consolidation of Monterey assets and liabilities at fair value effective from November 1, 1997. The pro forma effects had Monterey been consolidated at the beginning of either 1997 or 1996 would not have been material to Texaco's revenues, net income, and basic and diluted net income per common share for those years.

Note 5 Inventories

(Millions of dollars) As of December 31	1998	1997
Crude oil	$ 116	$ 308
Petroleum products and petrochemicals	799	893
Other merchandise	40	59
Materials and supplies	199	223
Total	$ 1,154	$ 1,483

The book value of inventories at December 31, 1998 is net of a valuation allowance of $99 million to adjust from cost to market. At December 31, 1997, the excess of estimated market over the book value of inventories was $204 million.

Note 6 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	1998	1997
Affiliates accounted for on the equity method		
Exploration and production		
United States	$ 230	$ 126
International		
CPI	452	437
Other	24	15
	706	578
Manufacturing, marketing and distribution		
United States		
Equilon	2,266	—
Motiva	896	—
Star	—	889
Other	29	178
International		
Caltex	1,747	1,860
Other	215	191
	5,153	3,118
Global gas marketing	71	55
Other affiliates	86	70
Total	6,016	3,821
Miscellaneous investments, long-term receivables, etc., accounted for at:		
Fair value	470	537
Cost, less reserve	698	739
Total	$ 7,184	$ 5,097

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	1998	1997	1996
Equity in net income (loss)			
Exploration and production			
United States	$ 37	$ 40	$ 36
International			
CPI	107	171	188
Other	(12)	—	1
	132	211	225
Manufacturing, marketing and distribution			
United States			
Equilon	199	—	—
Motiva	22	—	—
Star	(3)	95	14
Other	3	48	51
International			
Caltex	(36)	252	347
Other	15	20	22
	200	415	434
Global gas marketing	(26)	(20)	(3)
Other affiliates	12	10	13
Total	$ 318	$ 616	$ 669
Dividends received	$ 709	$ 332	$ 878

The undistributed earnings of these affiliates included in our retained earnings were $2,409 million, $2,658 million and $2,609 million as of December 31, 1998, 1997 and 1996.

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.

In 1996, Caltex completed the sale of its 50% interest in Nippon Petroleum Refining Company, Limited (NPRC) to its partner, Nippon Oil Company, for approximately $2 billion. Caltex' net income for 1996 includes a gain of $621 million associated with this sale. Our results include a net gain of $219 million relating to this sale, comprised of our equity share of the gain, less an adjustment in the carrying value of our investment and further reduced by a tax on the dividend distributed to the shareholders.

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.

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 share. 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 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 necessary to reflect contractual arrangements on the formation of Star, principally involving contributed inventories.

(Millions of dollars)	Equilon	Motiva	Star	Caltex Group	Other Affiliates	Total Texaco's Share
1998						
Gross revenues	$ 22,246	$ 5,371	$ 3,190	$17,174	$ 2,541	$22,856
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	$ 2,648	$ 1,435		$ 1,974	$ 687	$ 2,757
Noncurrent assets	7,758	5,306		7,684	2,021	9,332
Current liabilities	(4,058)	(1,248)		(2,840)	(727)	(3,932)
Noncurrent liabilities	(382)	(1,665)		(2,421)	(672)	(2,141)
Net equity	$ 5,966	$ 3,828		$ 4,397	$ 1,309	$ 6,016

(Millions of dollars)	Star	Caltex Group	Other Affiliates	Total Texaco's Share
1997				
Gross revenue	$ 7,758	$18,357	$ 4,028	$14,641
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
Noncurrent assets	3,260	7,193	3,607	6,324
Current liabilities	(769)	(2,991)	(1,032)	(2,270)
Noncurrent liabilities	(1,072)	(2,131)	(2,022)	(2,198)
Net equity	$ 2,461	$ 4,592	$ 1,500	$ 3,821

(Millions of dollars)	Star	Caltex Group	Other Affiliates	Total Texaco's Share
1996				
Gross revenue	$ 8,006	$18,166	$ 3,940	$14,644
Income before income taxes	$ 38	$ 2,175	$ 697	$ 1,310
Net income	$ 25	$ 1,193	$ 451	$ 669
As of December 31:				
Current assets	$ 816	$ 2,681	$ 1,049	$ 1,937
Noncurrent assets	3,204	6,714	3,853	6,354
Current liabilities	(704)	(2,999)	(1,182)	(2,329)
Noncurrent liabilities	(1,141)	(2,140)	(1,845)	(2,151)
Net equity	$ 2,175	$ 4,256	$ 1,875	$ 3,811

Note 7 Properties, Plant and Equipment

(Millions of dollars) As of December 31	Gross 1998	Gross 1997	Net 1998	Net 1997
Exploration and production				
United States	$ 21,993	$ 21,698	$ 7,963	$ 7,951
International	7,532	6,789	2,929	2,692
Total	29,525	28,487	10,892	10,643
Manufacturing, marketing and distribution				
United States	74	4,600	26	2,743
International	4,486	4,309	3,054	2,894
Total	4,560	8,909	3,080	5,637
Global gas marketing	647	593	271	224
Other	762	967	518	612
Total	$ 35,494	$ 38,956	$ 14,761	$ 17,116
Capital lease amounts included above	$ 264	$ 450	$ 79	$ 105

Accumulated depreciation, depletion and amortization totaled $20,733 million and $21,840 million at December 31, 1998 and 1997. Interest capitalized as part of properties, plant and equipment was $21 million in 1998, $20 million in 1997 and $12 million in 1996.

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

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 not transferred to the Equilon joint venture was $28 million. Fair value was determined by an independent appraisal.

In 1997, we recorded pre-tax charges of $63 million for the write-downs of impaired assets. These assets, consisting of producing properties and gas plants, were in the U.S. and international exploration and production operating segments. These charges were recorded to depreciation, depletion and amortization expense. Fair values were based on expected future discounted cash flows.

Note 8 Foreign Currency

Currency translations resulted in a pre-tax loss of $80 million in 1998, $59 million in 1997 and $60 million in 1996. After applicable taxes, 1998 included a loss of $94 million compared to a gain of $154 million in 1997 and a loss of $66 million in 1996.

After-tax currency impacts for the 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 1996 through 1998 were also impacted by the effect of currency rate changes on deferred income taxes denominated in British pounds. In 1998 and 1996, the U.S. dollar weakened against that currency causing us to record losses of $5 million and $58 million. In 1997, when the U.S. dollar strengthened, we recorded a gain of $28 million.

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 the years 1998, 1997 and 1996 these adjustments were losses of $2 million, $40 million and $126 million. The year 1996 includes the reversal of $60 million of previously deferred gains which were recognized in earnings due to the sale by Caltex of its investment in its Japanese affiliate, NPRC.

Note 9 Taxes

(Millions of dollars)	1998	1997	1996
Federal and other income taxes			
Current			
U.S. Federal	$ (45)	$ (538)	$ 359
Foreign	283	689	642
State and local	12	61	(16)
Total	250	212	985
Deferred			
U.S.	(104)	457	13
Foreign	(48)	(6)	(33)
Total	(152)	451	(20)
Total income taxes	98	663	965
Taxes other than income taxes			
Oil and gas production	70	127	114
Property	108	139	119
Payroll	119	125	120
Other	126	129	143
Total	423	520	496
Import duties and other levies			
U.S.	36	53	38
Foreign	6,843	5,414	4,127
Total	6,879	5,467	4,165
Total direct taxes	7,400	6,650	5,626
Taxes collected from consumers	2,148	3,370	3,237
Total all taxes	$ 9,548	$ 10,020	$ 8,863

The deferred income tax assets and liabilities included in the Consolidated Balance Sheet as of December 31, 1998 and 1997 amounted to $205 million and $145 million, as net current assets and $1,644 million and $1,825 million, as net noncurrent liabilities. The table that follows shows deferred income tax assets and liabilities by category:

	(Liability) Asset	
(Millions of dollars) As of December 31	1998	1997
Depreciation	$ (1,079)	$ (1,054)
Depletion	(429)	(601)
Intangible drilling costs	(726)	(826)
Other deferred tax liabilities	(686)	(755)
Total	(2,920)	(3,236)
Employee benefit plans	532	526
Tax loss carryforwards	641	728
Tax credit carryforwards	368	237
Environmental liabilities	116	167
Other deferred tax assets	639	580
Total	2,296	2,238
Total before valuation allowance	(624)	(998)
Valuation allowance	(815)	(682)
Total	$ (1,439)	$ (1,680)

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 hydrocarbon tax. Loss carry-forwards 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:

	1998	1997	1996
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	**(7.0)**	(4.7)	(5.5)
Aggregate earnings and losses from international operations	**10.4**	6.2	12.7
Tax adjustments	**(8.7)**	(.3)	(.4)
Sales of stock of subsidiaries	**(6.1)**	—	(6.3)
Energy credits	**(11.7)**	(1.4)	(1.9)
Other	**2.1**	(.2)	(1.2)
Effective income tax rate	**14.0%**	19.9%	32.4%

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 $194 million in 1998, $1,527 million in 1997 and $1,783 million in 1996. For companies with operations located outside the United States, pre-tax earnings on that basis aggregated $507 million in 1998, $1,800 million in 1997 and $1,200 million in 1996.

Income taxes paid, net of refunds, amounted to $430 million, $285 million and $917 million in 1998, 1997 and 1996.

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, 1998, amounted to $1,328 million and $2,226 million. The corresponding amounts at December 31, 1997 were $1,482 million and $2,313 million. Determination of the unrecognized U.S. deferred income taxes on these amounts is not practicable.

For the years 1998 and 1997, no loss carryforward benefits were recorded for U.S. Federal income taxes. For the year 1996, we recorded a benefit of $184 million for loss carryforwards. For the years 1998, 1997 and 1996, the tax benefits recorded for loss carryforwards were $30 million, $31 million and $16 million in foreign income taxes.

At December 31, 1998, we had worldwide tax basis loss carryforwards of approximately $1,692 million, including $967 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 $113 million at December 31, 1998, expiring at various dates through 2003. Alternative minimum tax and other tax credit carryforwards available for U.S. Federal income tax purposes were $368 million at December 31, 1998, of which $317 million have no expiration date. The remaining credits expire at various dates through 2013. 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 1998, we recorded tax credit carryforwards of $52 million for U.S. Federal income tax purposes.

Note 10 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	1998	1997
Notes payable to banks and others with originating terms of one year or less	**$ 368**	$ 473
Commercial paper	**1,617**	892
Current portion of long-term debt and capital lease obligations		
Indebtedness	**991**	1,005
Capital lease obligations	**13**	15
	2,989	2,385
Less short-term obligations intended to be refinanced	**2,050**	1,500
Total	**$ 939**	$ 885

The weighted average interest rates of commercial paper and notes payable to banks at December 31, 1998 and 1997 were 5.9% and 6.1%.

Long-term Debt and Capital Lease Obligations

(Millions of dollars) As of December 31	1998	1997
Long-Term Debt		
3-1/2% convertible notes due 2004	$ 204	$ 205
5.7% notes due 2008	201	—
6% notes due 2005	299	—
6-7/8% notes due 1999	200	200
6-7/8% debentures due 2023	196	195
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	147	147
8-1/4% debentures due 2006	150	150
8-3/8% debentures due 2022	198	198
8-1/2% notes due 2003	199	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
8.65% notes due 1998	—	200
8-7/8% debentures due 2021	150	150
9% notes due 1999	200	200
9-3/4% debentures due 2020	250	250
10.61% notes due 2005	—	206
Medium-term notes, maturing from 1999 to 2043 (7.5%)	543	489
Revolving Credit Facility, due 1999-2002 – variable rate (5.9%)	309	330
Pollution Control Revenue Bonds, due 2012 – variable rate (3.3%)	166	166
Other long-term debt:		
Texaco Inc. – Guarantee of ESOP Series F loan – variable rate (6.6%)	2	76
U.S. dollars (6.5%)	335	417
Other currencies (11.2%)	394	20
Total	5,238	4,893
Capital Lease Obligations (see Note 11)	68	134
	5,306	5,027
Less current portion of long-term debt and capital lease obligations	1,004	1,020
	4,302	4,007
Short-term obligations intended to be refinanced	2,050	1,500
Total long-term debt and capital lease obligations	$ 6,352	$ 5,507

The percentages shown for variable-rate debt are the interest rates at December 31, 1998. The percentages shown for the categories "Medium-term notes" and "Other long-term debt" are the weighted average interest rates at year-end 1998. Where applicable, principal amounts shown in the preceding schedule include unamortized premium or discount. Interest paid, net of amounts capitalized, amounted to $474 million in 1998, $395 million in 1997 and $433 million in 1996.

At December 31, 1998, 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 1998. 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 change in control.

At December 31, 1998, our long-term debt included $2.05 billion of short-term obligations scheduled to mature during 1999, 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, 1998 are as follows (in millions):

1999	2000	2001	2002	2003
$ 991	$ 211	$ 219	$ 246	$ 272

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. As part of our interest rate exposure management, 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, 1998 and 1997, excluding a combined interest rate and equity swap entered into in 1997. Derivative usage 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	1998	1997
Notes Payable and Commercial Paper:		
Carrying amount	$ 1,985	$ 1,365
Fair value	1,985	1,365
Related Derivatives – Payable (Receivable):		
Carrying amount	$ —	$ —
Fair value	17	3
Notional principal amount	$ 300	$ 300
Weighted average maturity (years)	8.3	9.3
Weighted average fixed pay rate	6.42%	6.42%
Weighted average floating receive rate	5.32%	6.09%
Long-Term Debt, including Current maturities:		
Carrying amount	$ 5,238	$ 4,893
Fair value	5,842	5,289
Related Derivatives – Payable (Receivable):		
Carrying amount	$ —	$ —
Fair value	(9)	(1)
Notional principal amount	$ 449	$ 544
Weighted average maturity (years)	8.4	.7
Weighted average fixed receive rate	6.24%	5.71%
Weighted average floating pay rate	5.03%	5.76%
Unamortized net gain on terminated swaps		
Carrying amount	$ 5	$ 8

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 floating rate and receive 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 at year-end 1998 and 1997 was not material.

During 1998, floating rate pay swaps having an aggregate notional principal amount of $503 million were amortized or matured. We initiated $466 million of new floating rate pay swaps. There was no activity in fixed rate pay swaps during 1998.

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 11 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, 1998, we had estimated minimum commitments for payment of rentals (net of noncancelable sublease rentals) under leases which, at inception, had a noncancelable term of more than one year, as follows:

(Millions of dollars)	Operating Leases	Capital Leases
1999	$ 154	$ 13
2000	112	12
2001	95	18
2002	323	8
2003	56	8
After 2003	320	21
Total lease commitments	$ 1,060	$ 80
Less interest		12
Present value of total capital lease obligations		$ 68

Operating lease commitments for 2002 include a $213 million residual value guarantee of leased production facilities. Payment is required only 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)	1998	1997	1996
Rental expense			
Minimum lease rentals	$ 208	$ 270	$ 259
Contingent rentals	—	3	10
Total	208	273	269
Less rental income on properties subleased to others	50	78	53
Net rental expense	$ 158	$ 195	$ 216

Note 12 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, reserves 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 $1 million in 1998, $2 million in 1997 and $15 million in 1996. Our contributions to the Employees Thrift Plan of Texaco Inc. and the Employees Savings Plan of Texaco Inc. amounted to $1 million in 1998, $2 million in 1997 and $26 million in 1996. 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. ESOP expenses in 1996 included $9 million for the 1995 employee incentive award program.

In 1998, 1997 and 1996, we paid $42 million, $44 million and $46 million in dividends on Series B and Series F stock. The trustee applies the dividends to fund interest payments which amounted to $5 million, $7 million and $10 million for 1998, 1997 and 1996, as well as to reduce principal on the ESOP loans. Dividends on the shares of Series B and Series F used to service debt of the Plans are tax deductible to the company. 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 reflect in our long-term debt the plans' original ESOP loans guaranteed by Texaco Inc. As we repay 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 1998, 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 recorded an after-tax charge of $80 million for employee separations, curtailment costs and special termination benefits associated with our previously-announced restructuring of our worldwide upstream and natural gas businesses, along with our corporate center restructuring and other cost-cutting initiatives, primarily in the international downstream areas. 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. Under the restructuring program, we estimate that over 1,400 employee reductions worldwide will occur, substantially by the end of the first quarter of 1999. Through December 31, 1998, we have terminated 433 employees and we paid $15 million of benefits under this program. The remaining benefits 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 companywide 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 1998, we paid $8 million of benefits under this program. The remaining benefits of $12 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.

Total worldwide expense for all employee pension plans of Texaco, including pension supplementations and smaller non-U.S. plans, was $92 million in 1998 and 1997 and $91 million in 1996. The following data are provided for principal U.S. and non-U.S. plans:

	Pension Benefits					
	1998		1997		Other U.S. Benefits	
(Millions of dollars) As of December 31	U.S.	Int'l	U.S.	Int'l	1998	1997
Changes in Benefit (Obligations)						
Benefit (obligations) at January 1	$ (1,769)	$ (835)	$ (1,657)	$ (801)	$ (756)	$ (699)
Service cost	(60)	(21)	(54)	(17)	(9)	(6)
Interest cost	(117)	(86)	(117)	(85)	(50)	(49)
Amendments	—	(3)	(18)	—	—	(5)
Actuarial gain/(loss)	(191)	(117)	(85)	(74)	8	(39)
Employee contributions	(4)	(3)	(4)	(1)	(12)	(10)
Benefits paid	240	70	182	59	56	53
Curtailments/settlements	17	—	—	—	(7)	—
Special termination benefits	(12)	—	—	(1)	(3)	—
Currency adjustments	—	16	—	85	—	—
Acquisitions/joint ventures	12	—	(16)	—	—	(1)
Benefit (obligations) at December 31	$ (1,884)	$ (979)	$ (1,769)	$ (835)	$ (773)	$ (756)
Changes in Plan Assets						
Fair value of plan assets at January 1	$ 1,702	$ 900	$ 1,483	$ 829	$ —	$ —
Actual return on plan assets	293	142	304	166	—	—
Company contributions	90	32	87	27	44	43
Employee contributions	4	3	4	1	12	10
Expenses	(6)	(2)	(5)	(2)	—	—
Benefits paid	(240)	(70)	(182)	(59)	(56)	(53)
Currency adjustments	—	23	—	(62)	—	—
Acquisitions/joint ventures	(17)	—	11	—	—	—
Fair value of plan assets at December 31	$ 1,826	$ 1,028	$ 1,702	$ 900	$ —	$ —

(Millions of dollars) As of December 31	Pension Benefits 1998 U.S.	Int'l	1997 U.S.	Int'l	Other U.S. Benefits 1998	1997
Funded Status of the Plans						
Obligation (greater than) less than assets	$ (58)	$ 49	$ (67)	$ 65	$ (773)	$ (756)
Unrecognized net transition asset	(14)	(14)	(21)	(23)	—	—
Unrecognized prior service cost	68	52	85	46	4	5
Unrecognized actuarial (gain)/loss	(93)	4	(100)	(53)	(92)	(94)
Net (liability)/asset recorded in Texaco's Consolidated Balance Sheet	$ (97)	$ 91	$ (103)	$ 35	$ (861)	$ (845)
Net (liability)/asset recorded in Texaco's Consolidated Balance Sheet consists of:						
Prepaid benefit asset	$ 72	$ 346	$ 64	$ 303	$ —	$ —
Accrued benefit liability	(215)	(268)	(195)	(299)	(861)	(845)
Intangible asset	23	12	21	22	—	—
Other accumulated nonowner equity	23	1	7	9	—	—
Net (liability)/asset recorded in Texaco's Consolidated Balance Sheet	$ (97)	$ 91	$ (103)	$ 35	$ (861)	$ (845)
Assumptions as of December 31						
Discount rate	6.75%	9.5%	7.0%	10.9%	6.75%	7.0%
Expected return on plan assets	10.0%	8.4%	10.0%	8.5%	—	—
Rate of compensation increase	4.0%	6.1%	4.0%	6.2%	4.0%	4.0%
Health care cost trend rate	—	—	—	—	4.0%	4.0%

(Millions of dollars) As of December 31	Pension Benefits 1998 U.S.	Int'l	1997 U.S.	Int'l	1996 U.S.	Int'l	Other U.S. Benefits 1998	1997	1996
Components of Net Periodic Benefit Expenses									
Service cost	$ 60	$ 21	$ 54	$ 17	$ 57	$ 16	$ 9	$ 6	$ 12
Interest cost	117	86	117	85	117	81	50	49	51
Expected return on plan assets	(136)	(79)	(132)	(66)	(130)	(64)	—	—	—
Amortization of transition asset	(4)	(10)	(5)	(8)	(5)	(8)	—	—	—
Amortization of prior service cost	11	7	10	6	10	6	—	—	—
Amortization of (gain)/loss	6	(2)	3	—	3	2	(4)	(5)	(1)
Curtailments/settlements	6	—	—	—	—	—	1	—	—
Special termination charges	8	—	—	—	—	—	2	—	—
Net periodic benefit expense	$ 68	$ 23	$ 47	$ 34	$ 52	$ 33	$ 58	$ 50	$ 62

For pension plans with accumulated obligations in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets were $414 million, $383 million and $0 as of December 31, 1998, and $412 million, $384 million and $11 million as of December 31, 1997.

We acquired Monterey on November 1, 1997, including their pension and postretirement benefit plans. We amended our plans to authorize Monterey to become a participating employer in our plans. 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. 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. 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	$ 5	$ (4)
Effect on postretirement benefit obligation	$ 52	$ (45)

Note 13 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, 1998, 1997 and 1996 available for awards during the subsequent year:

(Shares) As of December 31	1998	1997	1996
To all participants	12,677,325	9,607,506	7,027,010
To those participants not officers or directors	1,967,715	2,362,273	1,932,796
Total	14,645,040	11,969,779	8,959,806

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:

	1998	1997	1996
Shares	334,798	281,174	282,476
Weighted average fair value	$ 61.59	$ 55.09	$ 42.43

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 $17 million in 1998, $18 million in 1997 and $13 million in 1996. 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:

	1998	1997	1996
Net income (Millions of dollars)			
As reported	$ 578	$ 2,664	$ 2,018
Pro forma	$ 524	$ 2,621	$ 1,997
Earnings per share (dollars)			
Basic — as reported	$ .99	$ 4.99	$ 3.77
— pro forma	$ .89	$ 4.91	$ 3.73
Diluted — as reported	$ .99	$ 4.87	$ 3.68
— pro forma	$ .89	$ 4.79	$ 3.64

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

	1998	1997	1996
Expected life	2 yrs	2 yrs	3 yrs
Interest rate	5.4%	6.0%	6.1%
Volatility	22.5%	18.6%	15.0%
Dividend yield	3.0%	3.0%	3.3%

Option award activity during 1998, 1997 and 1996 is summarized in the following table:

	1998		1997		1996	
(Stock Options)	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding January 1	10,071,307	$ 53.31	9,436,406	$ 42.73	9,335,288	$ 33.45
Granted	2,388,593	61.56	2,084,902	55.06	2,040,530	42.43
Exercised	(7,732,978)	53.18	(9,533,861)	44.86	(8,088,040)	34.22
Restored	6,889,941	60.77	8,103,502	55.32	6,271,720	45.52
Canceled	(814)	78.08	(19,642)	51.43	(123,092)	36.77
Outstanding December 31	11,616,049	59.48	10,071,307	53.31	9,436,406	42.73
Exercisable December 31	5,945,445	58.93	3,197,262	51.21	2,853,236	39.20
Weighted-average fair value of options granted during the year		$ 8.48		$ 6.92		$ 5.50

The following table summarizes information on stock options outstanding at December 31, 1998:

	Options Outstanding			Options Exercisable	
Exercisable Price Range (per share)	Shares	Weighted-Average Remaining Life	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
$ 23.39 – 31.84	54,329	3.6 yrs.	$ 30.00	54,329	$ 30.00
$ 32.06 – 78.08	11,561,720	6.2 yrs.	$ 59.62	5,891,116	$ 59.20
$ 23.39 – 78.08	11,616,049	6.2 yrs.	$ 59.48	5,945,445	$ 58.93

Note 14 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 are cumulative and payable semiannually at the rate of $57 per annum.

Participants may partially convert Series B holdings into common stock beginning at age 55, and may elect full conversion upon retirement or separation from the company. Presently, each share of Series B entitles a participant to 25.7 votes, voting together with the holders of common stock, and is convertible into 25.736 shares of common stock. As an alternative to conversion, a participant can elect to receive $600 per share of Series B, payable in cash or common stock. If the participant elects cash, we will cause shares of common stock to be sold to fund such election. We may redeem the outstanding shares of Series B at $600 per share, subject to the participants' right to elect conversion to common stock at that time.

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, 1998, 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 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, each share of Series F was converted into 20 shares of common stock, after we called the Series F for redemption.

Market Auction Preferred Shares

There are outstanding 1,200 shares of cumulative variable rate preferred stock, called Market Auction Preferred Shares. 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 intervals.

During 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). For 1996, the annual dividend rate for the MAPS ranged between 3.90% and 4.19% and dividends totaled $12 million ($9,510, $11,043, $11,009 and $11,015 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 15 Financial Instruments

In the normal course of our business, we utilize various types of financial instruments. These instruments include recorded assets and liabilities, and also items such as derivatives which principally involve off-balance sheet risk.

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 and natural gas prices. We do not use derivatives for speculative purposes. Derivative transactions expose us to counterparty credit risk. We place contracts only with parties where credit-worthiness has been pre-determined under credit policies. Also, we employ dollar limits. 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, 1998 and 1997 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, 1998 and 1997 includes $72 million and $129 million of time deposits and $109 million and $47 million of commercial paper.

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, 1998, our available-for-sale securities had an estimated fair value of $492 million, including gross unrealized gains and losses of $40 million and $8 million. At December 31, 1997, our available-for-sale securities had an estimated fair value of $621 million, including gross unrealized gains and losses of $47 million and $13 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 $1,011 million in 1998, $1,040 million in 1997 and $1,503 million in 1996. These sales resulted in gross realized gains of $53 million in 1998, $48 million in 1997 and $51 million in 1996, and gross realized losses of $22 million, $19 million, and $17 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, 1998 and 1997 carrying values of $331 million and $197 million.

SHORT-TERM DEBT, LONG-TERM DEBT AND RELATED DERIVATIVES
Refer to Note 10 for additional information about debt and related derivatives outstanding at December 31, 1998 and 1997.

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	$ 370	$ 60
British pounds	1,476	440
Danish krone	449	237
Dutch guilders	303	13
New Zealand dollars	126	13
Other European currencies	179	77
Other currencies	50	43
Total at December 31, 1998	$ 2,953	$ 883
Total at December 31, 1997	$ 1,845	$ 606

Market risk exposure on these contracts is essentially limited to currency rate movements. At year-end 1998, there were $8 million unrealized gains and $19 million unrealized losses related to these contracts. At year-end 1997, there were $5 million unrealized gains and $29 million 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 1998 and 1997, hedges of foreign currency commitments principally involved capital projects requiring expenditure of British pounds and Danish krone. The percentages of planned capital expenditures hedged at year-end were: British pounds – 54% in 1998 and 62% in 1997; Danish krone – 40% in 1998 and 74% in 1997. 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 1998 and 1997, net hedging gains of $50 million and $51 million, respectively, had yet to be amortized.

Contracts to sell foreign currencies are primarily related to 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 16 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.

At December 31, 1998 and 1997, 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 $4,397 million and $974 million at year-end 1998 and 1997. 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 1998 were $161 million and $140 million, respectively. At year-end 1997, unrealized gains and losses were $93 million and $58 million, respectively.

Note 16 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, 1998, the balance sheet includes liabilities of $285 million for future environmental remediation costs. Also, we have accrued $794 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. However, while future environmental expenditures in the petroleum industry are expected to be significant, they will be a cost of doing business that will have to be recovered in the marketplace. Moreover, it is not believed that such future costs will 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 1998, 1997 and 1996.

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 5.1% for 1998 and 5.9% for both 1997 and 1996. 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 1998, 1997 and 1996 totaled $24 million for each year. Annual dividends on Series B totaled $6 million for 1998 and $7 million for both 1997 and 1996.

Series A and Series B are redeemable under certain circumstances and, at the option of Texaco Capital LLC (with Texaco Inc.'s consent) in whole or in part, from time to time, at $25 per share on or after October 31, 1998 for Series A and June 30, 1999 for Series B, plus, in each case, 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 1998 and 1997, the carrying amount and the fair value of this transaction were not material.

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.

Financial Guarantees

We have guaranteed the payment of certain debt, lease commitments and other obligations of third parties and affiliate companies. These guarantees totaled $797 million and $372 million at December 31, 1998 and 1997. The year-end 1998 amount includes $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.

Additionally, in June 1997, our 50% owned affiliate, Caltex Petroleum Corporation (Caltex), received a claim from the United States Internal Revenue Service for $292 million in excise taxes, $140 million in penalties and $1.6 billion in interest. The IRS claim relates to sales of crude oil by Caltex to Japanese customers beginning in 1980. Caltex believes that the underlying claim for excise taxes and penalties is wrong and that the claim for interest is flawed. We believe that this claim is without merit and is not anticipated to be materially important in relation to our consolidated financial position or results of operations. In February 1999, the original letter of credit to the IRS for $2.3 billion, which Caltex arranged in order to litigate this claim, was increased to $2.5 billion. Texaco and its 50% partner, Chevron Corporation, have severally guaranteed Caltex' letter of credit obligation to a syndicate of banks.

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, 1998 and 1997, our maximum exposure to loss was estimated to be $500 million and $525 million.

However, based on our right of counterclaim against Equilon and unaffiliated third parties in the event of nonperformance, our net exposure was estimated to be $195 million and $422 million at December 31, 1998 and 1997.

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

Other Commitments

During 1997, 1996 and 1995, we sold leasehold interests in certain equipment not yet in service and received British pound payments totaling $530 million. Under a related agreement, in 1997 we leased back these leasehold interests. We made a British pound payment in 1997, which released us from future lease commitments under this agreement. This payment effectively repurchased the leasehold interests previously sold.

Litigation

Texaco and approximately fifty other oil companies are defendants in seventeen 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 twenty-four other defendants have executed a settlement agreement with most of the plaintiffs that will resolve many of these disputes. The federal court in Texas has preliminarily approved the settlement and is considering final approval. Similar claims by the federal and 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 that these financial records are being accurately and objectively maintained and that the company's assets are being protected. The internal control system comprises:

- Corporate Conduct Guidelines that require 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 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 seven 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

Robert C. Oelkers
Vice President and 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, 1998 and 1997, and the related statements of consolidated income, cash flows, stockholders' equity and nonowner changes in equity for each of the three years in the period ended December 31, 1998. 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 generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Texaco Inc. and subsidiary companies as of December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998 in conformity with generally accepted accounting principles.

Arthur Andersen LLP
February 25, 1999
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)

	Consolidated Subsidiaries					Equity	
	United States	Other West	Europe	Other East	Total	Affiliate – Other East	World-wide
Developed reserves	1,125	52	142	413	1,732	350	2,082
Undeveloped reserves	216	2	208	62	488	88	576
As of December 31, 1995	1,341	54	350	475	2,220	438	2,658
Discoveries & extensions	82	4	80	29	195	1	196
Improved recovery	20	—	—	—	20	81	101
Revisions	44	2	6	21	73	(3)	70
Net purchases (sales)	(23)	—	3	(1)	(21)	—	(21)
Production	(142)	(4)	(42)	(58)	(246)	(54)	(300)
Total changes	(19)	2	47	(9)	21	25	46
Developed reserves	1,100	50	165	418	1,733	354	2,087
Undeveloped reserves	222	6	232	48	508	109	617
As of December 31, 1996*	1,322	56	397	466	2,241	463	2,704
Discoveries & extensions	107	13	34	61	215	4	219
Improved recovery	15	—	65	—	80	18	98
Revisions	55	3	11	100	169	22	191
Net purchases (sales)	413	(2)	(31)	(8)	372	—	372
Production	(145)	(5)	(45)	(66)	(261)	(56)	(317)
Total changes	445	9	34	87	575	(12)	563
Developed reserves	1,374	54	210	463	2,101	354	2,455
Undeveloped reserves	393	11	221	90	715	97	812
As of December 31, 1997*	1,767	65	431	553	2,816	451	3,267
Discoveries & extensions	**70**	**2**	**8**	**32**	**112**	**1**	**113**
Improved recovery	**136**	**—**	**16**	**3**	**155**	**156**	**311**
Revisions	**46**	**(15)**	**22**	**55**	**108**	**137**	**245**
Net purchases (sales)	**(38)**	**—**	**—**	**26**	**(12)**	**—**	**(12)**
Production	**(157)**	**(4)**	**(58)**	**(71)**	**(290)**	**(61)**	**(351)**
Total changes	**57**	**(17)**	**(12)**	**45**	**73**	**233**	**306**
Developed reserves	**1,415**	**39**	**246**	**490**	**2,190**	**456**	**2,646**
Undeveloped reserves	**409**	**9**	**173**	**108**	**699**	**228**	**927**
As of December 31, 1998*	**1,824**	**48**	**419**	**598**	**2,889**	**684**	**3,573**
*Includes net proved NGL reserves							
As of December 31, 1996	207	1	54	1	263	6	269
As of December 31, 1997	246	—	71	—	317	4	321
As of December 31, 1998	**272**	**—**	**68**	**—**	**340**	**6**	**346**

Net Proved Reserves of Natural Gas

(Billions of Cubic Feet)

	Consolidated Subsidiaries					Equity	
	United States	Other West	Europe	Other East	Total	Affiliate – Other East	World-wide
Developed reserves	3,666	522	452	84	4,724	140	4,864
Undeveloped reserves	396	325	492	3	1,216	15	1,231
As of December 31, 1995	4,062	847	944	87	5,940	155	6,095
Discoveries & extensions	436	263	34	3	736	15	751
Improved recovery	8	—	—	—	8	1	9
Revisions	(99)	(1)	58	13	(29)	—	(29)
Net purchases (sales)	(53)	(7)	—	1	(59)	—	(59)
Production	(626)	(71)	(75)	(4)	(776)	(18)	(794)
Total changes	(334)	184	17	13	(120)	(2)	(122)
Developed reserves	3,360	893	452	96	4,801	136	4,937
Undeveloped reserves	368	138	509	4	1,019	17	1,036
As of December 31, 1996	3,728	1,031	961	100	5,820	153	5,973
Discoveries & extensions	692	26	92	346	1,156	2	1,158
Improved recovery	7	—	22	—	29	5	34
Revisions	228	75	41	(22)	322	19	341
Net purchases (sales)	10	(118)	(7)	(310)	(425)	—	(425)
Production	(643)	(96)	(81)	(2)	(822)	(17)	(839)
Total changes	294	(113)	67	12	260	9	269
Developed reserves	3,379	792	576	110	4,857	145	5,002
Undeveloped reserves	643	126	452	2	1,223	17	1,240
As of December 31, 1997	4,022	918	1,028	112	6,080	162	6,242
Discoveries & extensions	**599**	**6**	**47**	**98**	**750**	**1**	**751**
Improved recovery	**4**	**—**	**7**	**—**	**11**	**3**	**14**
Revisions	**152**	**(12)**	**(6)**	**34**	**168**	**10**	**178**
Net purchases (sales)	**(39)**	**—**	**—**	**250**	**211**	**—**	**211**
Production	**(633)**	**(92)**	**(112)**	**(17)**	**(854)**	**(25)**	**(879)**
Total changes	**83**	**(98)**	**(64)**	**365**	**286**	**(11)**	**275**
Developed reserves	**3,345**	**688**	**615**	**374**	**5,022**	**135**	**5,157**
Undeveloped reserves	**760**	**132**	**349**	**103**	**1,344**	**16**	**1,360**
As of December 31, 1998	**4,105**	**820[a]**	**964**	**477**	**6,366[a]**	**151**	**6,517[a]**

(a) Additionally, there is approximately 586 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 1998	**166%**	**144%**	**191%**
Year 1997	167%	132%	212%
Year 1996	113%	83%	154%
3 year average	150%	120%	187%
5 year average	138%	113%	171%

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 liquids and gas. Future production and development costs are based on current year costs. Extensive judgement 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, 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
As of December 31, 1996							
Future cash inflows from sale of oil & gas, and service fee revenue	$ 41,807	$ 2,863	$11,242	$ 9,261	$ 65,173	$ 6,632	$ 71,805
Future production costs	(8,080)	(894)	(2,368)	(1,993)	(13,335)	(1,776)	(15,111)
Future development costs	(2,790)	(141)	(2,094)	(551)	(5,576)	(740)	(6,316)
Future income tax expense	(10,444)	(758)	(1,946)	(5,099)	(18,247)	(2,181)	(20,428)
Net future cash flows before discount	20,493	1,070	4,834	1,618	28,015	1,935	29,950
10% discount for timing of future cash flows	(8,602)	(458)	(1,740)	(489)	(11,289)	(695)	(11,984)
Standardized measure of discounted future net cash flows	$ 11,891	$ 612	$ 3,094	$ 1,129	$ 16,726	$ 1,240	$ 17,966

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. The large reduction in the 1998 standardized measure due to change in price reflects the sharp drop in crude oil and natural gas prices during 1998.

➤ *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

(Millions of dollars)	Worldwide Including Equity in Affiliate – Other East 1998	1997	1996
Standardized measure – beginning of year	$ 12,057	$ 17,966	$ 11,872
Sales of minerals-in-place	(160)	(79)	(458)
	11,897	17,887	11,414
Changes in ongoing oil and gas operations:			
Sales and transfers of produced oil and gas, net of production costs during the period	(3,129)	(4,921)	(4,859)
Net changes in prices, production and development costs	(11,205)	(14,632)	8,820
Discoveries and extensions and improved recovery, less related costs	728	2,681	3,182
Development costs incurred during the period	1,770	1,976	1,575
Timing of production and other changes	(1,170)	(969)	(251)
Revisions of previous quantity estimates	852	1,476	527
Purchases of minerals-in-place	48	449	138
Accretion of discount	1,916	3,027	1,952
Net change in discounted future income taxes	3,780	5,083	(4,532)
Standardized measure – end of year	$ 5,487	$ 12,057	$ 17,966

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 7 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, 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
As of December 31, 1997							
Proved properties	$ 20,196	$ 581	$ 4,584	$ 1,623	$ 26,984	$ 1,112	$ 28,096
Unproved properties	1,248	16	89	225	1,578	338	1,916
Support equipment and facilities	438	26	37	228	729	578	1,307
Gross capitalized costs	21,882	623	4,710	2,076	29,291	2,028	31,319
Accumulated depreciation, depletion and amortization	(13,849)	(298)	(3,135)	(1,131)	(18,413)	(1,013)	(19,426)
Net capitalized costs	$ 8,033	$ 325	$ 1,575	$ 945	$ 10,878	$ 1,015	$ 11,893

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 1998 we spent $3.45 for each BOE we added. Finding and development costs averaged $3.91 for the three-year period 1996-1998 and $3.75 per BOE for the five-year period 1994-1998.

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, 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
For the year ended December 31, 1996							
Proved property acquisition	$ 56	$ —	$ —	$ —	$ 56	$ —	$ 56
Unproved property acquisition	91	5	—	20	116	—	116
Exploration	356	18	90	225	689	9	698
Development	827	107	384	113	1,431	144	1,575
Total	$ 1,330	$ 130	$ 474	$ 358	$ 2,292	$ 153	$ 2,445

*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			
		1998		1997		1996	**1998**	1997	1996
United States	**$ 10.14**	**$ 1.93**	$ 16.32	$ 2.32	$ 16.97	$ 2.10	**$ 4.07**	$ 3.94	$ 3.82
Other West	**9.65**	**.92**	14.40	1.03	16.80	.96	**1.86**	2.80	3.44
Europe	**11.73**	**2.42**	18.41	2.42	20.37	2.47	**5.24**	5.58	5.95
Other East	**9.61**	**.38**	16.87	1.89	18.61	3.20	**3.65**	4.11	4.07
Affiliate – Other East	**9.81**	—	14.89	—	16.30	—	**2.68**	3.76	3.71

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, 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
For the year ended December 31, 1996							
Gross revenues from:							
Sales and transfers, including affiliate sales	$ 3,383	$ —	$ 524	$ 863	$ 4,770	$ 648	$ 5,418
Sales to unaffiliated entities	310	140	475	181	1,106	45	1,151
Production costs	(937)	(54)	(321)	(215)	(1,527)	(183)	(1,710)
Exploration costs	(196)	(27)	(57)	(150)	(430)	(8)	(438)
Depreciation, depletion and amortization	(652)	(24)	(310)	(107)	(1,093)	(110)	(1,203)
Other expenses	(241)	(1)	(1)	(40)	(283)	8	(275)
Results before estimated income taxes	1,667	34	310	532	2,543	400	2,943
Estimated income taxes	(534)	(26)	(112)	(417)	(1,089)	(212)	(1,301)
Net results	$ 1,133	$ 8	$ 198	$ 115	$ 1,454	$ 188	$ 1,642

Supplemental Market Risk Disclosures

We use derivative financial instruments to hedge interest rate, foreign currency exchange and market rate 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 10, 15 and 16 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 $2.7 billion and $2.0 billion at year-end 1998 and 1997, before effects of related interest rate swaps. Interest rate swap notional amounts at year-end 1998 decreased by less than $100 million from year-end 1997.

Based on our overall interest rate exposure on variable rate debt and interest rate swaps at December 31, 1998 (including the interest rate and equity swap), a hypothetical two percentage points increase or decrease in interest rates would not materially affect our consolidated financial position, net income or cash flows.

Forward Exchange and Option Contracts

In 1998, the net notional amount of open forward contracts increased by $831 million. This related mostly to hedging of increased balance sheet monetary exposures.

The effect on fair value of our forward exchange contracts at year-end 1998 from a hypothetical 10% change in currency exchange rates would be an increase or decrease of approximately $207 million. This would be offset by an opposite effect on the related hedged exposures.

Petroleum and Natural Gas Hedging

In 1998, the notional amount of open derivative contracts increased by $3,423 million, mostly related to natural gas hedging.

For commodity derivatives permitted to be settled in cash or another financial instrument, sensitivity effects are as follows. At year-end 1998, the aggregate effect of a hypothetical 25% change in natural gas prices, a 15% change in crude oil prices and a 16-21% change in petroleum product prices (dependent on product and location) would not materially affect 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 1998, market risk exposure decreased by $129 million. At year-end 1998, a 10% appreciation or depreciation in debt and equity prices would change portfolio fair value by about $49 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 1998	First Quarter	Second Quarter	Third Quarter	Fourth Quarter 1997
Revenues								
Sales and services	$ 7,922	$ 7,729	$ 7,481	$ 7,778	$ 11,813	$ 10,983	$ 10,834	$ 11,557
Equity in income of affiliates, interest, asset sales and other	225	315	226	31	216	513	259	492
	8,147	8,044	7,707	7,809	12,029	11,496	11,093	12,049
Deductions								
Purchases and other costs	6,114	5,972	5,836	6,257	9,298	8,671	8,355	8,906
Operating expenses	580	645	593	690	781	790	806	874
Selling, general and administrative expenses	276	296	290	362	419	417	450	469
Exploratory expenses	141	90	93	137	99	93	114	165
Depreciation, depletion and amortization	388	375	409	503	385	372	388	488
Interest expense, taxes other than income taxes and minority interest	249	240	237	233	261	247	220	272
	7,748	7,618	7,458	8,182	11,243	10,590	10,333	11,174
Income (loss) before income taxes and cumulative effect of accounting change	399	426	249	(373)	786	906	760	875
Provision for (benefit from) income taxes	140	84	34	(160)	(194)	335	270	252
Income (loss) before cumulative effect of accounting change	259	342	215	(213)	980	571	490	623
Cumulative effect of accounting change	(25)	—	—	—	—	—	—	—
Net income (loss)	$ 234	$ 342	$ 215	$ (213)	$ 980	$ 571	$ 490	$ 623
Total nonowner changes in equity	$ 264	$ 344	$ 210	$ (246)	$ 939	$ 596	$ 476	$ 590
Net income (loss) per common share (dollars)								
Basic								
Income (loss) before cumulative effect of accounting change	$ .46	$ .62	$ .38	$ (.43)	$ 1.86	$ 1.07	$ .91	$ 1.15
Cumulative effect of accounting change	(.05)	—	—	—	—	—	—	—
Net income (loss)	$ .41	$ .62	$ .38	$ (.43)	$ 1.86	$ 1.07	$ .91	$ 1.15
Diluted								
Income (loss) before cumulative effect of accounting change	$ .46	$ .61	$ .38	$ (.43)	$ 1.80	$ 1.05	$ .90	$ 1.12
Cumulative effect of accounting change	(.04)	—	—	—	—	—	—	—
Net income (loss)	$ .42	$ .61	$ .38	$ (.43)	$ 1.80	$ 1.05	$ .90	$ 1.12

See accompanying notes to consolidated financial statements.

Five-Year Comparison of Selected Financial Data

(Millions of dollars)	1998	1997	1996	1995	1994
For the year:					
Revenues from continuing operations	$ 31,707	$ 46,667	$ 45,500	$ 36,787	$ 33,353
Net income (loss) before cumulative effect of accounting changes					
Continuing operations	$ 603	$ 2,664	$ 2,018	$ 728	$ 979
Discontinued operations	—	—	—	—	(69)
Cumulative effect of accounting changes	(25)	—	—	(121)	—
Net income	$ 578	$ 2,664	$ 2,018	$ 607	$ 910
Total nonowner changes in equity	$ 572	$ 2,601	$ 1,863	$ 592	$ 972
Net income (loss) per common share (dollars)					
Basic					
Income (loss) before cumulative effect of accounting changes					
Continuing operations	$ 1.04	$ 4.99	$ 3.77	$ 1.29	$ 1.72
Discontinued operations	—	—	—	—	(.14)
Cumulative effect of accounting changes	(.05)	—	—	(.24)	—
Net income	$ .99	$ 4.99	$ 3.77	$ 1.05	$ 1.58
Diluted					
Income (loss) before cumulative effect of accounting changes					
Continuing operations	$ 1.04	$ 4.87	$ 3.68	$ 1.28	$ 1.72
Discontinued operations	—	—	—	—	(.14)
Cumulative effect of accounting changes	(.05)	—	—	(.23)	—
Net income	$ .99	$ 4.87	$ 3.68	$ 1.05	$ 1.58
Cash dividends per common share (dollars)	$ 1.80	$ 1.75	$ 1.65	$ 1.60	$ 1.60
Total cash dividends paid on common stock	$ 952	$ 918	$ 859	$ 832	$ 830
At end of year:					
Total assets	$ 28,570	$ 29,600	$ 26,963	$ 24,937	$ 25,505
Debt and capital lease obligations					
Short-term	$ 939	$ 885	$ 465	$ 737	$ 917
Long-term	6,352	5,507	5,125	5,503	5,564
Total debt and capital lease obligations	$ 7,291	$ 6,392	$ 5,590	$ 6,240	$ 6,481

See accompanying notes to consolidated financial statements.

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Janet L. Stoner
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Kjestine M. Anderson
Secretary and
Corporate Communications

Michael N. Ambler
General Tax Counsel

James F. Link
Treasurer

Changes

➤ Carl B. Davidson, Vice President and Secretary of Texaco Inc., retired on May 1, 1998, after 33 years of service. He reached the company's normal retirement age.

➤ Kjestine M. Anderson was elected as Secretary of Texaco Inc., effective May 1, 1998.

➤ Deval L. Patrick joined the company as a Vice President and General Counsel of Texaco Inc., effective February 8, 1999.

➤ David C. Crikelair, Vice President of Texaco Inc., resigned effective February 25, 1999, to join Equilon Enterprises LLC as Chief Financial Officer.

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 25, 1999, there were 209,728 shareholders of record. In 1998, Texaco's common stock price reached a high of $65.00, and closed December 31, 1998, at $53.00.

	Common Stock Price Range				Dividends	
	High	Low	High	Low		
	1998		1997*		1998	1997*
First Quarter	$ 65	$ 49 1/16	$ 55 3/4	$ 48 7/8	$ .45	$ .425
Second Quarter	63 3/4	55 3/4	57 7/16	50 1/2	.45	.425
Third Quarter	64 7/8	55 1/4	61 11/16	54 11/32	.45	.45
Fourth Quarter	63 7/8	50 1/4	63 7/16	51 1/8	.45	.45

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

Stock Transfer Agent and Shareholder Communications

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

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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

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

Annual Meeting

Texaco Inc.'s Annual Shareholders Meeting will be held at the Rye Town Hilton, Rye Brook, NY, on Tuesday, April 27, 1999. A formal notice of the meeting, together with a proxy statement and proxy form, is being mailed to shareholders 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. 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.

Publications for Shareholders

In addition to the *Annual Report,* Texaco issues several financial and informational publications which are available free of charge to interested shareholders on request from Investor Services:

***Texaco Inc.'s 1998 Annual Report on Form 10-K* filed with the U.S. Securities and Exchange Commission.**

Financial and Operational Supplement – Comprehensive data on Texaco's 1998 activities.

Equal Opportunity and Diversity: 1998 Report From Texaco – A description of Texaco's programs that foster equal employment opportunity.

Equality and Fairness Task Force Report – A report on Texaco's human resources programs.

Safety, Health, and Environment Review – A report on Texaco's programs, policies and results in the areas of safety, health and environment is available on Texaco's Internet site at www.texaco.com.

The use in this report of the term Texaco Inc. refers solely to Texaco Inc., a Delaware corporation. The use of such terms as Texaco, company, division, unit, organization, we, us, our and its, when referring either to Texaco Inc. and its consolidated subsidiaries or to subsidiaries and affiliates either individually or collectively, is only for convenience and is not intended to describe legal relationships. Texaco Inc.'s significant subsidiaries are listed as an exhibit to Texaco Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission.

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