

ChevronTexaco



Powering Performance

2003 Annual Report



Powering Performance

Becoming the world's top-performing energy company requires the ability to produce sustainable, long-term results. ChevronTexaco's drive to deliver results is reflected in 2003's strong financial and operating performance. It is also reflected in our commitment to deliver results the right way – by creating a work environment that fuels innovation, empowers people and builds partnerships based on trust, integrity and mutual benefit.

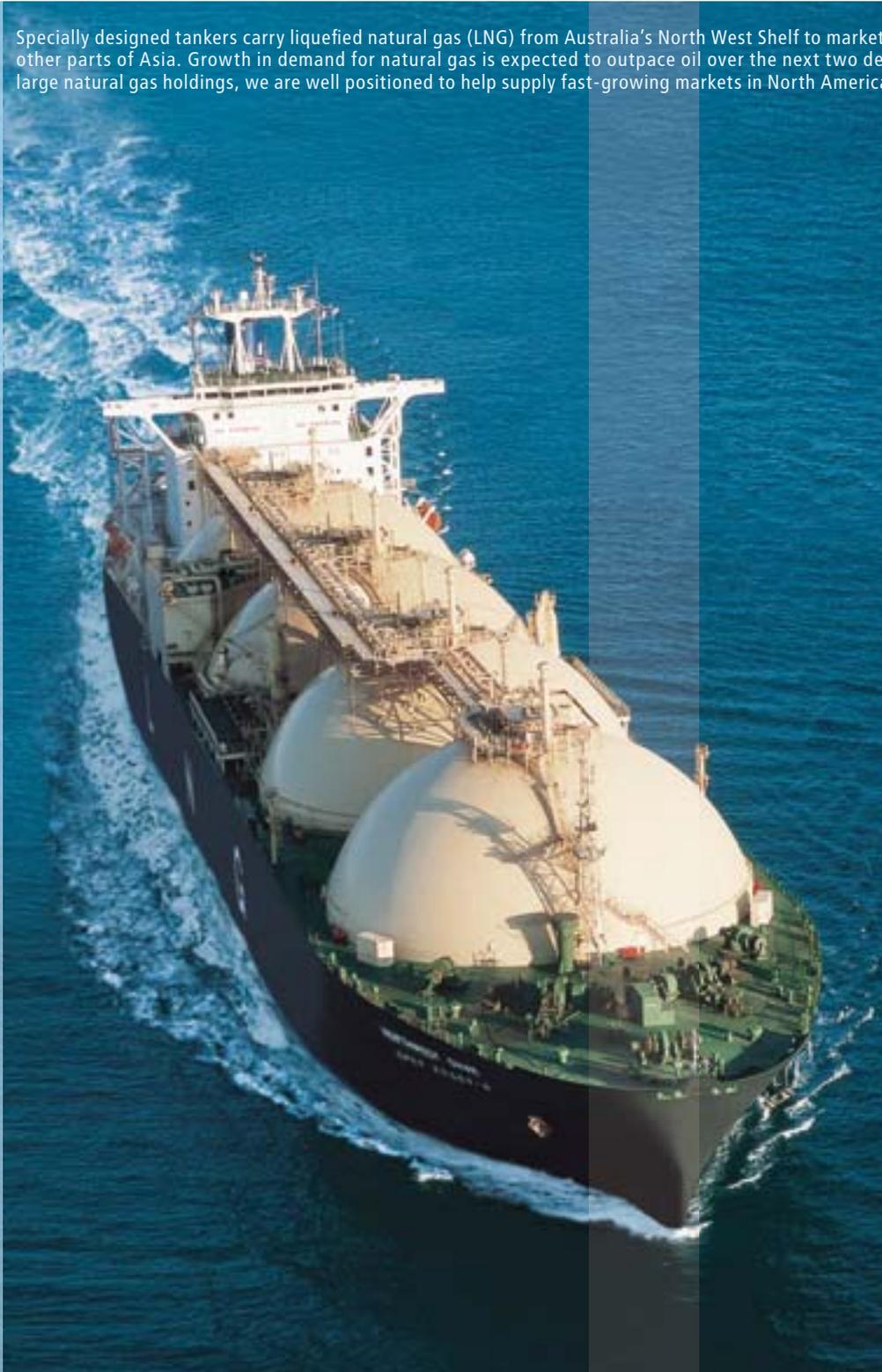
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ChevronTexaco's performance is based on running safe, reliable operations; being a good steward of the environment; and managing capital wisely.

Specially designed tankers carry liquefied natural gas (LNG) from Australia's North West Shelf to markets in Japan and other parts of Asia. Growth in demand for natural gas is expected to outpace oil over the next two decades. With our large natural gas holdings, we are well positioned to help supply fast-growing markets in North America and Asia.



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TO OUR STOCKHOLDERS

Last year, I wrote of the challenge ChevronTexaco faced to improve its financial performance. I am pleased to report that we are succeeding. Not only was 2003 one of our best years ever, but we also built a solid foundation that should enable us to deliver sustained, strong performance into the future and continue to achieve our long-stated goal to be No. 1 in total stockholder return among our peer group.

In 2003, net income was \$7.2 billion, resulting in a 15.7 percent annual return on capital employed. Our strong cash flow enabled us to reduce debt \$3.7 billion, ending the year with a total debt to total debt-plus-equity ratio of 25.8 percent. For the 16th consecutive year, we increased our annual dividend payment. Our financial performance was reflected in our total stockholder return of 35.2 percent in 2003. Since 2000, we have led our largest three competitors in total stockholder return.

Other significant achievements included:

- continuing successes in exploration, with major new discoveries in the deepwater U.S. Gulf of Mexico and Nigeria;
- replacing more than 100 percent of production for the 11th consecutive year;
- achieving significant progress in major upstream projects in Angola, Canada, Chad, Kazakhstan, Nigeria and Venezuela;
- establishing a global natural gas business and achieving milestones in the commercialization of our vast Australian and West African gas resources;
- significantly improving performance in refining and marketing.

OUR STRATEGIES – STEPPING UP THE PACE Our global upstream strategy is to grow profitability in our core areas and build new legacy positions. We are well positioned to do both. Our crude oil and natural gas production is located in large basins around the globe where we have existing infrastructure and are typically one of the top three producers. We have a queue of projects that will add to production throughout the decade and beyond. We hold exploratory acreage in some of the most promising regions of the world, and we are confident we can build on an already successful exploratory program. In 2003, we established a business development group responsible for identifying and developing new, large-scale resource opportunities throughout the world.

Our global natural gas strategy is to commercialize our large equity resource base by targeting the rapidly growing North American and Asian markets. In the Atlantic Basin, we are pursuing several liquefied natural gas (LNG) projects that would supply the first offshore LNG regasification terminal in the United States. In the Pacific Basin, we are expanding our successful LNG business in Australia to supply markets in North America and Asia. We also are moving forward on a gas-to-liquids project in Nigeria.

Our global downstream strategy is to improve future returns by focusing on areas of market and supply strength. Our core areas of operation include the U.S. West Coast, U.S. Gulf of Mexico, Asia and Latin America. In 2003, we initiated a major restructuring of our global downstream operations. We are committed to achieving before-tax profit improvements of \$500 million by the end of 2005 through cost reductions, efficiency improvements and the standardization of key work processes.

DELIVERING TOP PERFORMANCE While we are proud of the value we have created, we recognize that the confidence of stockholders rests in their expectation of future performance, not in past accomplishments.

'AS WE LOOK AHEAD, WE SEE MANY OPPORTUNITIES TO CREATE EVER-HIGHER VALUE FOR OUR STOCKHOLDERS, AND WE ARE WELL POSITIONED TO COMPETE FOR THOSE OPPORTUNITIES. WE HAVE A STRONG BALANCE SHEET, A PORTFOLIO OF EXCELLENT ASSETS, LEADING-EDGE TECHNOLOGY, AND TALENTED AND COMMITTED PEOPLE.'



To deliver the performance you expect, we will continue to focus on operational excellence and capital stewardship. Operational excellence means safe, reliable and environmentally sound execution. 2003 was our safest year ever. Reliability metrics improved in many areas, as did environmental performance. Capital stewardship means making better-quality expenditure decisions and executing projects well. We have made considerable progress in both areas, resulting in improved capital allocation and efficiency over the past three years.

The successes we enjoyed in 2003 came from the contributions of the talented men and women of ChevronTexaco. They embraced the challenge and delivered results – and did so the right way, by acting with integrity and high ethical standards.

Many of our employees work in some of the world's most challenging regions. This year, our company was honored to receive the U.S. Department of State's 2003 Award for Corporate Excellence. The award recognized the sustained efforts of our employees in Nigeria to contribute to a higher quality of life in that country.

125 YEARS OF PROGRESS As we look ahead, we see many opportunities to create ever-higher value for our stockholders, and we are well positioned to compete for those opportunities. We have a strong balance sheet, a portfolio of excellent assets, leading-edge technology, and talented and committed people.

In 2004, we will mark the 125th anniversary of the incorporation of the Pacific Coast Oil Company, the oldest predecessor company of ChevronTexaco. For 125 years, we have produced reliable, affordable energy and have taken pride in knowing that the energy we produce is a building block for economic development and helps improve the standard of living around the world. This anniversary causes us to reflect upon our past accomplishments and successes, but it also reminds us of our responsibility to build for the next 125 years.

Handwritten signature of Dave O'Reilly

DAVE O'REILLY

*Chairman of the Board and Chief Executive Officer
February 25, 2004*

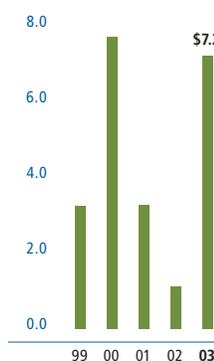
CHEVRONTEXACO FINANCIAL HIGHLIGHTS

Millions of dollars, except per-share amounts

	2003	2002	% Change
Net income	\$ 7,230	\$ 1,132	539 %
Sales and other operating revenues	\$ 120,032	\$ 98,691	22 %
Capital and exploratory expenditures*	\$ 7,363	\$ 9,255	(20)%
Total assets at year-end	\$ 81,470	\$ 77,359	5 %
Total debt at year-end	\$ 12,597	\$ 16,269	(23)%
Stockholders' equity at year-end	\$ 36,295	\$ 31,604	15 %
Cash flow from operating activities	\$ 12,315	\$ 9,943	24 %
Common shares outstanding at year-end (Thousands)	1,069,148	1,068,137	–
Per-share data			
Net income before cumulative effect of changes in accounting principles – diluted	\$ 7.14	\$ 1.07	567 %
Net income – diluted	\$ 6.96	\$ 1.07	550 %
Cash dividends	\$ 2.86	\$ 2.80	2 %
Stockholders' equity	\$ 33.95	\$ 29.59	15 %
Common stock price at year-end	\$ 86.39	\$ 66.48	30 %
Total debt to total debt-plus-equity ratio	25.8%	34.0%	
Return on average stockholders' equity	21.3%	3.5%	
Return on average capital employed (ROCE)	15.7%	3.2%	

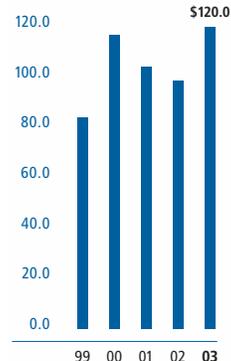
* Includes equity in affiliates

NET INCOME
Billions of dollars



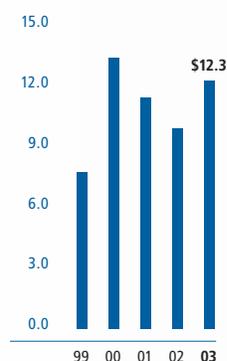
Net income rose sharply on the strength of upstream operations and much-improved results from the downstream businesses in 2003. Special-item charges in 2002 reduced earnings more than \$3 billion.

SALES & OTHER OPERATING REVENUES
Billions of dollars



Sales and other operating revenues increased 22 percent on higher prices for crude oil, natural gas and refined products.

CASH PROVIDED BY OPERATING ACTIVITIES
Billions of dollars



Higher earnings helped boost the company's operating cash flow by 24 percent.

ANNUAL CASH DIVIDENDS
Dollars per share



The company increased its annual dividend payout for the 16th consecutive year.

CHEVRONTEXACO OPERATING HIGHLIGHTS¹

	2003	2002	% Change
Net production of crude oil and natural gas liquids (Thousands of barrels per day)	1,808	1,897	(5)%
Net production of natural gas (Millions of cubic feet per day)	4,292	4,376	(2)%
Net oil-equivalent production (Thousands of oil-equivalent barrels per day)	2,523	2,626	(4)%
Refinery input (Thousands of barrels per day)	1,991	2,079	(4)%
Sales of refined products (Thousands of barrels per day)	3,738	3,775	(1)%
Net proved reserves of crude oil, condensate and natural gas liquids ² (Millions of barrels)	8,599	8,668	(1)%
Net proved reserves of natural gas ² (Billions of cubic feet)	20,191	19,335	4 %
Net proved oil-equivalent reserves ² (Millions of barrels)	11,964	11,890	1 %
Number of employees at year-end ³	50,582	53,014	(5)%

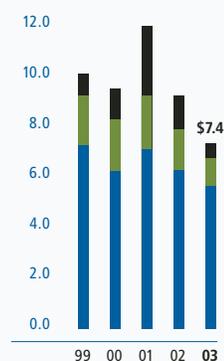
¹ Includes equity in affiliates, except number of employees

² At the end of the year

³ Excludes service station personnel

CAPITAL & EXPLORATORY EXPENDITURES*

Billions of dollars



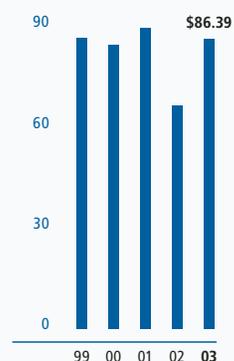
■ Chemicals & Other
■ Refining, Marketing & Transportation
■ Exploration & Production

Capital and exploratory expenditures declined about 20 percent from the 2002 level that included the acquisition of assets previously leased, higher investments in a Canadian oil sands project and additional investments in equity affiliates.

*Includes equity in affiliates

CHEVRONTEXACO YEAR-END COMMON STOCK PRICE*

Dollars per share

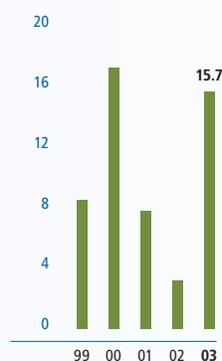


The company's stock price rose 30 percent during 2003, outpacing the broader market indexes.

*Chevron - 1999 and 2000

RETURN ON AVERAGE CAPITAL EMPLOYED

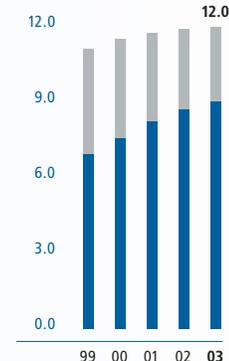
Percentage



Higher profits helped boost ChevronTexaco's return on capital employed to 15.7 percent.

NET PROVED RESERVES

Billions of BOE*



■ United States
■ International**

Net proved reserves additions in 2003 equaled 108 percent of oil-equivalent production for the period. This was the 11th consecutive year that reserve additions exceeded 100 percent of production.

*Barrels of oil-equivalent
**Includes equity in affiliates

WE ARE PRODUCING STRONG RESULTS IN OUR MAIN BUSINESSES. IN GLOBAL UPSTREAM, 2003 WAS ONE OF OUR BEST YEARS FOR EXPLORATION, AND WE REACHED MILESTONES IN MAJOR CRUDE OIL AND NATURAL GAS PROJECTS. A GLOBAL GAS BUSINESS WAS LAUNCHED AND PROGRESS MADE IN COMMERCIALIZING OUR LARGE NATURAL GAS RESOURCES. GLOBAL DOWNSTREAM DROVE FOR NEW EFFICIENCIES AS IT REORGANIZED ITS OPERATIONS.



Producing

Resu

GLOBAL UPSTREAM

The objective of our global upstream business is to grow profitability in our core areas and build large, new legacy positions. We are well positioned to do both.

ChevronTexaco is the top crude oil and natural gas producer in Angola and Kazakhstan and the top crude oil producer in Indonesia. It is one of the largest crude oil and natural gas producers in the United States, West Africa, Asia-Pacific and Latin America. We also are the only international oil company allowed to operate on behalf of the Kingdom of Saudi Arabia in the Partitioned Neutral Zone between Saudi Arabia and Kuwait. ChevronTexaco is the No. 1 holder of natural gas resources in Australia and has significant positions in North America, West Africa, Kazakhstan and Latin America.

We are one of the world's largest producers of heavy oil, which represents an estimated one-third of our hydrocarbon reserves. Heavy oil assets include fields in the San Joaquin Valley in California, where we are the largest heavy oil producer; the Hamaca project in Venezuela; Indonesia, site of the world's largest steamflood project; and the Athabasca oil sands in Canada.

Our exploration interests are focused on the world's most promising areas, including the deepwater U.S. Gulf of Mexico and West Africa.

► **Results and Opportunities** During the year, we made significant progress on a number of fronts, including major development projects, exploration successes, commercial agreements, the acquisition of promising new exploration acreage and portfolio upgrades.

For the 11th consecutive year, proved crude oil and natural gas reserves replacement exceeded 100 percent. The company added approximately 1 billion oil-equivalent barrels of net proved reserves, or 108 percent of volumes produced in 2003. Additions included the results of contract extensions in Denmark and Colombia, drilling activities in the United States, improved recovery techniques in Indonesia and the United States, and revisions from reservoir studies and analyses in Kazakhstan.

In 2003, three major developments were completed. In Africa, the Chad-Cameroon project came onstream and sales began. The development is expected to reach a maximum production rate of 225,000 total barrels per day in mid-2004. In Canada, the start-up of integrated operations was completed for the Athabasca Oil Sands Project. Full capacity is expected to reach 155,000 barrels of bitumen per day. In Kazakhstan, we completed a major pipeline extension to move Karachaganak processed liquids to world markets.

The company has a slate of other major crude oil and natural gas developments that will be moving forward in 2004. Production facilities are being constructed

GLOBAL UPSTREAM

- Deepwater U.S. Gulf of Mexico discoveries made at Sturgis, Perseus, Tubular Bells and Saint Malo; agreement reached to operate Blind Faith prospect.
- Deepwater drilling success achieved in Nigeria at Aparo, Nsiko and Usan.
- First crude oil production and sales begun from Chad-Cameroon project.
- Start-up of integrated operations completed for Canada's Athabasca Oil Sands Project.
- Export pipeline completed to allow transport of processed liquids from Karachaganak Field in Kazakhstan to world markets.
- Oil-equivalent proved reserves additions exceeded production for the 11th consecutive year.

GLOBAL GAS

- Progress made in the Greater Gorgon Area development: approval in-principle for an LNG facility on Barrow Island and letter agreement with the China National Offshore Oil Corporation to purchase production and an equity stake in the development, pending completion of formal contracts.
- Licenses awarded for construction of Port Pelican LNG terminal offshore Louisiana in the United States and for operatorship of Plataforma Deltana Block 2 offshore Venezuela.
- Permits filed to construct LNG terminal offshore Baja California, Mexico, to serve North American markets.

GLOBAL DOWNSTREAM

- Reorganization completed by functional rather than geographic areas to lower costs and create new efficiencies.
- Projects completed at three refineries to enable the manufacture of cleaner fuels and to increase the yield of high-value products.
- Richmond, California, refinery in the United States achieved its best-ever refinery utilization rate.



for two developments in Angola. The \$1.9 billion Sanha condensate gas utilization and Bomboco crude oil project is under way and expected to reach a maximum production rate of more than 100,000 total barrels of oil-equivalent per day by 2006. The first phase of the \$2.2 billion Benguela Belize-Lobito Tomboco development is expected to start up by late 2005 from the Benguela and Belize fields. The second phase of the project will bring the Lobito and Tomboco fields onstream. Both phases are expected to be completed in 2007 with a maximum production rate expected to exceed 200,000 total barrels of crude oil per day. In Nigeria, the company reached agreements that cleared the way for developing the deepwater Agbami project. Agbami is expected to reach a maximum production rate of 250,000 total barrels of crude oil per day within six to 12 months after it comes onstream in 2007. In Kazakhstan, we hold a 50 percent interest in Tengizchevroil (TCO), which includes the supergiant Tengiz and Korolev oil fields. In 2003, TCO reached an agreement with the government of Kazakhstan to expand operations in both fields. The expansion, scheduled for completion in the second half of 2006, is expected to increase TCO's crude oil production capacity to between 430,000 and 500,000 barrels per day. In the U.S. Gulf of Mexico, we are moving forward with the development of the deepwater Tahiti Field. The Tahiti Field is estimated to hold 400 million to 500 million barrels of ultimately recoverable oil-equivalent reserves.

In late 2004, upgrading facilities are expected to be completed for the Hamaca heavy oil project. Located in Venezuela's Orinoco Basin, Hamaca will have the capacity to upgrade 190,000 barrels of heavy oil per day.

A number of major exploration successes also were made during the year, including discoveries in the deepwater U.S. Gulf of Mexico and Nigeria. In 2003, the company acquired new exploration acreage in the Gulf of Thailand, Plataforma Deltana Block 2 in Venezuela, Block 249 in Nigeria and the Orphan Basin offshore eastern Canada.

During 2003, work began to upgrade the upstream portfolio and sell lower-value noncore assets. Sales have been announced or completed for properties in North America, Papua New Guinea, U.K. North Sea, Bangladesh and Kazakhstan. The company plans to continue to upgrade its upstream portfolio, while investing in large crude oil and natural gas developments that can deliver long-term value. Aiding our effort to build new legacy positions is a business development group, which is assessing opportunities in resource-rich areas of the world.

GLOBAL GAS

ChevronTexaco operates in some of the world's most prolific natural gas basins and is well positioned to help meet the anticipated growth in worldwide natural gas demand. We hold the largest natural gas resources in Australia and have significant holdings in West Africa, North America, Kazakhstan and Latin America. The primary focus of our global gas business is to commercialize our substantial equity resource base, targeting North American and Asian markets.

► **Results and Opportunities** Early in the year, we created a new global gas business that will integrate and coordinate natural gas production, transportation and marketing capabilities. The group also has oversight of the company's interest in power generation, gasification technology and the gas-to-liquids (GTL) joint venture, Sasol Chevron.

Early in 2003, Global Gas established a natural gas marketing presence in the United States. It also reached milestones on key liquefied natural gas (LNG) and GTL projects in both the Atlantic and Pacific Basins.

In the Atlantic Basin, gas from West Africa and South America is expected to be delivered to U.S. markets through the Port Pelican LNG facility, which will be located 40 miles (64 km) off the coast of Louisiana. Port Pelican is expected to be the first offshore terminal in the United States to regasify LNG. It will be capable of handling up to 1.6 billion cubic feet of natural gas per day.

THE GORGON-BARROW ISLAND CONNECTION

Over the past 40 years, ChevronTexaco has produced some 300 million barrels of crude oil from Barrow Island, a Class A Nature Reserve located 35 miles (56 km) offshore northwest Australia. Today, Barrow Island is recognized as the industry standard for how crude oil operations can coexist with the most sensitive and diverse ecosystems. With the development of the giant Greater Gorgon Area fields, Barrow Island is now destined to be an important part of our efforts to commercialize our natural gas resources. After careful review, including rigorous environmental studies, state authorities approved in-principle the limited use of Barrow Island as the site for a new liquefied natural gas facility. The Greater Gorgon Area fields represent a significant percentage of Australia's total known natural gas resources.



In the Pacific Basin, we are moving forward to commercialize our resources in Australia for markets in North America and Asia. In 2003, we reached milestones in developing the giant Greater Gorgon Area natural gas fields, offshore northwest Australia. State authorities granted in-principle approval for the restricted use of Barrow Island for a new LNG facility. Following that, China National Offshore Oil Corporation signed a letter agreement to purchase a significant volume of Gorgon LNG for the fast-growing Chinese market, as well as to purchase an equity stake in the Gorgon Field development. This agreement, which is subject to completing formal contracts, is expected to lead to one of the largest LNG transactions in the industry's history. Gorgon natural gas also is destined for North American markets. ChevronTexaco has filed permits to build an LNG import and regasification terminal offshore Baja California, Mexico, to receive the gas and move it to market.

In West Africa, we expect to award construction contracts in 2004 for a GTL project in Nigeria that will use Sasol Chevron technology. We are pursuing other GTL projects in Qatar and Australia and continuing to reduce the costs of GTL facilities to improve their competitiveness.

GLOBAL DOWNSTREAM

Downstream is working to improve returns by focusing on areas of market and supply strength. We have interests in 21 wholly owned and affiliated fuel refineries with a combined processing capacity of more than 2 million barrels per day. We have a worldwide marketing network in 84 countries and have approximately 24,000 retail outlets, including those of affiliate companies. Our motor fuel brands – Chevron, Texaco and Caltex – are well established and among the most respected in the industry. In the United States, we are among the top three gasoline marketers on the West Coast and in the Sun Belt area – regions with growing populations and increasing income. Outside the United States, we are a leading marketer in the Caribbean, South Korea, Australia and Southeast Asia.

► **Results and Opportunities** To improve its competitive performance, global downstream has restructured its business along functional rather than geographic areas. The reorganization is expected to offer greater opportunities for capturing revenues, lowering costs, improving safety and reliability, and sharing best practices. By the end of 2005, this business expects to deliver approximately \$500 million in pretax profit improvements.

Significant operational enhancements were made in several parts of the business in 2003, which are now being implemented elsewhere in the organization. An example is the Richmond, California, refinery in the United States. In 2003, Richmond achieved its highest refinery utilization rate, improved its safety record by more than 28 percent and reduced environmental incidents by more than 60 percent. The global lubricants business increased U.S. sales volumes by 10 percent, despite an industry decline, and maintained its No. 1 premium base oil position on the U.S. West Coast.

During the year, major capital projects were completed at the Pascagoula, Mississippi, refinery in the United States; the Pembroke Refinery in Wales, United Kingdom; and the Nerefco Refinery in Rotterdam, Netherlands. These projects will enable the facilities to meet requirements for low-sulfur fuel. The company's remaining refinery network is able to meet sulfur specifications.

In marketing, an aggressive effort continued to strengthen brands and customer satisfaction ratings. In 2003, two independent industry surveys identified Chevron and Texaco as having the highest brand value in their respective U.S. markets. On July 1, 2004, ChevronTexaco gains nonexclusive rights to the Texaco brand in the United States and will begin selling gasoline under both the Chevron and Texaco brands in U.S. markets.

Global downstream is upgrading its asset portfolio to focus on strategic areas. As a result, our investments in about 1,500 company-owned or -leased service stations are being sold. During the year, the El Paso, Texas, refinery in the United States was sold and the Batangas Refinery in the Philippines was converted into a product import terminal.

Several initiatives were completed in 2003 that strengthened the performance of the company's main businesses. Three refineries were upgraded to meet sulfur guidelines for motor fuel; a major pipeline

extension was completed to move processed liquids from Karachaganak, Kazakhstan, to world markets; and an aggressive effort continued to strengthen the Chevron, Texaco and Caltex brands.



PRODUCING RESULTS

Strong performance was delivered across all of ChevronTexaco's key operations in 2003. Here are just a few of our results.

Angola

TOP PRODUCER With production of more than 500,000 total barrels of crude oil per day, ChevronTexaco is Angola's largest producer. Two major developments are under way that are expected to reach a maximum production rate of approximately 300,000 total barrels of oil-equivalent per day by 2007.



Nigeria

AGBAMI'S PROMISE In 2003, the company moved forward with the development of Agbami, a deep-water field containing approximately 800 million barrels of ultimately recoverable oil-equivalent reserves. Initial production is expected in 2007.



Asia-Pacific

BRAND STRENGTH Through our Caltex brand, we have a significant marketing presence in Australia, China, Thailand, South Korea, Philippines, Singapore, New Zealand, Malaysia and South Africa. Caltex and associated brands are sold in approximately 30 countries across Asia-Pacific, southern Africa and East Africa.



Kazakhstan

EXPANSION PROGRESS In 1993, ChevronTexaco signed an agreement with newly independent Kazakhstan to form Tengizchevroil (TCO), the country's first petroleum joint venture. In 2003, the 10th anniversary of that historic occasion, production from TCO averaged 280,000 total barrels of crude oil per day. An expansion is now under way that is expected to increase TCO's total crude oil production capacity to between 430,000 and 500,000 barrels per day when the project is completed in the second half of 2006. Also in 2003, a 400-mile (644-km) pipeline extension was completed to transport processed liquids from the Karachaganak Field to world markets.

Australia

GAS COUNTRY A record amount of liquefied natural gas (LNG) was sold in 2003 by the 16.7 percent-owned North West Shelf joint venture in Australia. An expansion is now under way to accommodate increased production, and a ninth LNG carrier, to be operated by ChevronTexaco, will go into service in 2004. ChevronTexaco is Australia's largest holder of natural gas resources.





Gulf of Mexico

WELL EQUIPPED ChevronTexaco is the largest producer of crude oil and natural gas on the U.S. Gulf of Mexico Shelf and we operate the second largest number of leased blocks in the deep water. In 2003, we made four deepwater discoveries and drilled four successful appraisal wells. We also moved forward with developing our 58 percent-owned Tahiti deepwater field. Tahiti is estimated to contain 400 million to 500 million total barrels of ultimately recoverable oil-equivalent reserves.



United States

CUSTOMERS' CHOICE ChevronTexaco is committed to meeting the needs of all its customers, whether it is by supplying high-performing, clean-burning fuels to drivers or groceries through its convenience stores. In 2004, the company gains nonexclusive rights to the Texaco brand in the United States and will begin selling gasoline under both the Chevron and Texaco brands in U.S. markets.

DRIVING EXCELLENCE

OUR SUCCESS IS DRIVEN BY OUR COMMITMENT TO OPERATIONAL EXCELLENCE. WE HAVE RIGOROUS PROCESSES IN PLACE TO ENSURE THAT WE OPERATE SAFELY, RELIABLY AND WITH CARE FOR THE ENVIRONMENT. AT THE SAME TIME, WE TAKE A DISCIPLINED APPROACH TO INVESTING OUR CAPITAL AND MANAGING OUR PROJECTS.



IN 2003, WE ACHIEVED OUR BEST YEAR EVER IN SAFETY. ALTHOUGH OUR SAFETY PERFORMANCE IS STEADILY IMPROVING, WE WILL NOT BE SATISFIED UNTIL WE REACH OUR GOAL OF ZERO INCIDENTS – NO ONE INJURED.

Across each of our businesses, we focus on operational excellence. This is a disciplined approach aimed at taking our performance to world-class levels in the areas of health, safety, reliability, efficiency and environmental performance.

SAFETY In 2003, we achieved our best year ever in safety. The total recordable incident rate (per 200,000 hours worked) for employees and contractors was 0.60, down 18 percent from 2002. Over the past two years, we have seen a 30 percent improvement in contractor safety. This was largely the result of special initiatives that require suppliers to meet stringent health and safety standards before submitting bids for work. We also are making progress in motor vehicle safety, one of the leading causes of fatalities for the company. In 2003, a comprehensive road safety

management system was put in place and new companywide guidelines issued to promote safe driving habits.

RELIABILITY When people, processes and equipment perform dependably, there is less chance of injury and environmental damage and less chance of lost revenue. In 2003, ChevronTexaco developed and deployed tools and processes to improve operating reliability. Early results are showing benefits in all sectors of the business, from lower maintenance costs and downtime to greater pipeline reliability and improved refinery efficiencies.

THE ENVIRONMENT At ChevronTexaco, we integrate environmental considerations into business decisions, always seeking new ways to minimize pollution and waste, conserve natural resources, and enhance our understanding of how our business may affect the environment.

As part of this effort, the company tracks the amount of energy consumed in its operations. In 2003, we used 1 percent less energy than the previous year, representing savings of \$28 million. Since 1992, the year we began tracking, we have reduced companywide energy use by 22 percent.

A wholly owned subsidiary, Chevron Energy Solutions (CES), works with external partners and internal business units to help them find and implement ways to save energy in their operations. In late 2003, the U.S. Department of Defense and the U.S. Department of Energy awarded CES multiple performance-based contracts to engineer and install facility improvements at three military bases. The improvements are expected to save U.S. taxpayers at least \$151 million and reduce greenhouse gas emissions by approximately 1.5 million tons.

In 2003, significant progress was made in reducing the number and volume of oil spills. Over the year, the company experienced 1,145 spills, nearly 25 percent less than in 2002. The volume spilled was 26,500 barrels, a 50 percent reduction from the previous year. Less than 1 percent of the spilled oil went to water and a little more than half of the total spilled volume was recovered immediately. In all instances, areas affected by spills were cleaned up and remediated. The company has set a goal to reduce spills by 20 percent per year through 2006.

In 2003, we developed comprehensive software to estimate and manage greenhouse gas emissions. In an effort to standardize and compare emissions data, we are distributing the software at no charge to others in the industry. At the end of 2003, approximately 80 companies and organizations had requested copies of our emissions software.

STEERING PROJECT SUCCESS

In 2004, ChevronTexaco's capital and exploratory budget is estimated to be \$8.5 billion. We follow a disciplined approach to ensure that these funds are directed toward the highest-quality opportunities with the greatest potential for enabling growth and increasing stockholder value.

We evaluate opportunities through the ChevronTexaco Project Development and Execution Process, a project management method that is considered one of the industry's best. The process not only helps us to identify the best projects, but also to execute them well. It is used in front-end engineering work to identify potential problems, as well as to improve scheduling and minimize late changes.

We also conduct peer reviews to share best practices. These reviews can help accelerate a project or lead to a new approach.

An example is the deepwater Agbami Field, a major crude oil development offshore Nigeria. A project team, along with our technology and services company, enhanced the original development plan by finding greater efficiencies in the drilling, design and construction of the project. The findings of the peer review are now being applied in developing the giant Tahiti Field in the U.S. Gulf of Mexico.

IMPROVING RELIABILITY



In the U.S. Gulf of Mexico (far left), a dedicated team of experts trained in reliability engineering is helping to predict and prevent equipment and process failures on approximately 400 platforms.

Aviation personnel in Taiwan (near left) were among thousands of global downstream employees who took part in ChevronTexaco's International Safety Day. The event identified safety enhancements that are now being adopted throughout our downstream operations.

FUELING INNOVATION

THE IDEAS OF A TALENTED AND SKILLED WORK FORCE FUEL INNOVATION AND HELP POWER CHEVRONTEXACO'S PERFORMANCE AND GROWTH. THIS CREATIVE ENERGY IS CHanneled TO INCREASE EFFICIENCIES, SOLVE BUSINESS CHALLENGES, LOWER COSTS AND DELIVER GREATER VALUE TO OUR STOCKHOLDERS.

Our approach to managing technology is delivering results in two ways: through the deployment of technology to enhance the performance of our core hydrocarbon businesses and through the development of technologies to expand future business capabilities.

INTEGRATED APPROACH Because major new developments often call for both upstream and downstream expertise, we merged our formerly separate technology groups from these sectors in 2003. This created an organization unique in the industry – one that gives us an integrated approach to managing technology resources across business segments.

SUPPORTING OUR BUSINESSES Our technology group is helping to carry out the objectives of our main businesses. Upstream, our proprietary imaging technology enables us to explore for and develop new crude oil and natural gas reservoirs with greater precision and at a lower cost than ever before. We are working to develop a next-generation reservoir simulator that will significantly increase speed in simulation performance and allow us to better model large and complex reservoirs. We also are investing in our proprietary heavy oil upgrading technology. This technology yields high-value liquids without producing coke or other low-value byproducts.

The company's proprietary HALIAS™ technology, monitored in the control room shown below, enables hydrogen to be produced from natural gas for use in fuel cells. The company is involved in a full range of research to develop energy from hydrocarbons as well as to produce alternate fuels as future markets develop.

At right, proprietary technology increases reactor efficiency and catalyst life in refineries, thereby driving down costs and improving utilization rates.



Our technology group is working with Global Gas to commercialize our very large natural gas resources. Liquefied natural gas (LNG) receiving terminals, such as the one we are planning to construct offshore Louisiana in the United States, will use advanced LNG unloading and transfer systems. Our activities in gas-to-liquids (GTL) technology include research and development for next-generation conversion technology and step-out technologies in GTL plants under construction.

Downstream, our El Segundo, California, refinery in the United States is piloting proprietary reactor technology that improves catalyst life and enhances reliability. The technology is expected to lower El Segundo's operating costs. The company expects to deploy this technology to other reactors in its worldwide refinery system.

A PARTNER OF CHOICE Partnerships are an important part of Chevron-Texaco's approach to technology. Internally, our researchers work with business units to improve current and future performance. Externally, our partnerships are with academic, business and public-sector organizations. These partnerships enable us to share technical risk, cost and talent with others that have complementary capabilities.

Our partnerships with universities and other academic institutions have long been an important and successful part of our research effort. Over the last three years, we have established research centers at three U.S. universities: University of Tulsa, Colorado School of Mines and University of Southern California. These centers conduct research aimed at solving actual problems that exist in our business today and provide the opportunity for our employees to earn advanced degrees.

POSITIONING FOR THE FUTURE Our investments in energy technologies such as hydrogen and renewables position us to provide clean, economically viable energy from hydrocarbons and alternate sources as future markets develop and technical challenges are overcome.

We also are active in technologies such as advanced materials that will improve our operational performance or become potential new sources of revenue. Two key areas of research are hydrogen fuel and the rapidly emerging field of nanotechnology. In 2003, the U.S. Department of Energy awarded Chevron-Texaco a grant to explore new fuel processing technology based on hydrogen. The project will build a prototype fuel processor to supply hydrogen from natural gas to fuel cells that produce electrical power for businesses, homes and vehicles. In nanotechnology, we are producing a series of new molecular building blocks, called diamondoids, from certain petroleum resources. They could potentially be used for electronic materials, specialty coatings, polymers and other advanced materials.



Our advanced proprietary imaging technology enables us to visualize the full extent of the Tahiti Field, one of the largest crude oil and natural gas reservoirs discovered to date in the U.S. Gulf of Mexico. Such technologies are contributing to our success in adding reserves and resources through both exploration and reservoir management.

CONNECTED BY TECHNOLOGY

A business focus guides our approach in the fast-evolving information technology (IT) area. Our IT global digital infrastructure was completed in 2003, connecting 50,000 desktops and 1,800 company locations. Going forward, the project is expected to save approximately \$50 million per year by eliminating duplicate processes and systems.

A global network enables online "real time" collaboration across the world's time zones. When engineers face technical challenges, they can tap into an online network to find solutions from colleagues anywhere in the world who may have solved similar problems. This reduces downtime, duplicated effort and associated costs.

EMPOWERING PEOPLE

AT CHEVRONTEXACO, WE BELIEVE A SUCCESSFUL COMPANY DELIVERS BETTER RESULTS WHEN IT EMPOWERS NOT ONLY ITS EMPLOYEES, BUT ALSO ITS PARTNERS. WE HAVE AN UNWAVERING COMMITMENT TO BEING AN EXCELLENT EMPLOYER AND A TRUSTWORTHY, COLLABORATIVE PARTNER.

Approximately 51,000 ChevronTexaco employees work around the clock and around the globe to deliver energy where it is needed, when it is needed. It is their commitment and good work that drive our company's success. ChevronTexaco people embody the strong values of our company, readily share knowledge with one another and respond quickly to deliver the results that our stockholders expect of us – and we expect of ourselves.

We have a number of programs in place to ensure we attract and maintain a superior, ethical and performance-minded work force. We offer competitive salaries, benefits and programs that reward outstanding individual, team and companywide performance.

Most employees participate in success-sharing programs or other variable pay plans. These provide a cash payout in addition to base pay. They are tied to measurable results such as total stockholder return or to a business unit's specific financial and operating targets, including safety.

Employees also have extensive training and development opportunities for personal and professional growth. Last year, approximately 300 engineering, earth science and other graduates participated in Horizons, a fast-track upstream program designed to prepare new employees for assignments across the world. Horizons is managed by ChevronTexaco Technical University, which provides training in upstream and downstream technologies as well as other business skills.

DIVERSITY Our work force represents the global nature of our company. We value our diversity, consider it a competitive advantage and leverage it to achieve our business goals. We support diversity initiatives through a system of nine global networks, each one open to all employees. The networks provide an opportunity for mentoring and career development.

OUR VISION: TO BE THE GLOBAL ENERGY COMPANY MOST ADMIRABLE FOR ITS PEOPLE, PARTNERSHIP AND PERFORMANCE.



TURNING PARTNERSHIP INTO ENERGY

As the world changes and our business evolves with it, so does our definition of partnership. ChevronTexaco has always worked to contribute to the quality of life wherever it operates. Because many of our operations are in the developing world, we are taking additional steps to ensure that our business is a mutual success for our company, the local community and the host country.

We are forming new types of partnerships with development agencies, nongovernmental organizations and financial institutions to encourage broad economic growth. We recognize that strong and healthy economies not only contribute to a nation's standard of living, but also help create safer societies, more stable governments and a better investment climate for business.

Programs such as our Angola Partnership Initiative, involving the U.S. Agency for International Development and the United Nations Development Programme, are aimed at helping an entire nation as it tries to rebuild following years of civil strife. The mission of the initiative is to build human self-sufficiency with a focus on developing small- and medium-size enterprises.

Such initiatives are designed to make a lasting contribution without the need for permanent oil industry involvement. In Papua New Guinea, the Community Development Initiative Foundation, which we established, is continuing to provide social services to rural communities although we sold our business interests and exited the country in 2003. The foundation has its own staff and facilities and has obtained funding from other sources to ensure its sustainability and growth.

In the countries in which we operate, it is our practice to hire and train employees from the national work force, transfer technology, and buy goods and services from local suppliers. Additionally, we provide financial assistance to help new service companies develop and expand. We believe these are the best ways we can contribute to the economic and social development of our host communities.



THE CHEVRONTEXACO WAY

Our core values and the principles that guide the way we do business are outlined in a document we call *The ChevronTexaco Way*. In 2003, we went further to communicate our principles, policies and achievements as a global citizen. The first *ChevronTexaco Corporate Responsibility Report* contains information about the actions we are taking on a wide range of topics including human rights, climate change, diversity, global work-force development and political activities. It also cites areas where the company is committed to improve. The report, along with *The ChevronTexaco Way*, is available on our Web site, www.chevrontexaco.com.

EXPLORING SOLUTIONS

IN TODAY'S WORLD, BUSINESS PERFORMANCE IS INCREASINGLY MEASURED IN SOCIAL AS WELL AS FINANCIAL TERMS. AS CEO DAVE O'REILLY PUTS IT, "THE WAY WE ACHIEVE RESULTS IS AS IMPORTANT AS THE RESULTS THEMSELVES." HERE, HE ADDRESSES SEVERAL OF THE COMPLEX ISSUES OUR INDUSTRY FACES AS IT OPERATES IN SOME OF THE MOST SOCIALLY AND ECONOMICALLY CHALLENGING AREAS OF THE WORLD.

YOU HAVE SAID THAT GLOBAL POVERTY IS THE DEFINING CHALLENGE OF THE 21ST CENTURY. WHY IS THIS IMPORTANT TO CHEVRONTEXACO AND ITS STOCKHOLDERS?

Business must care about world poverty not only for ethical and moral reasons, but also because it is in our financial interest to care. Poverty is at the root of many of the intractable problems that the world is experiencing today, including disease and political instability. It is estimated that one-half of the world's population exists on the equivalent of \$2 a day, and more than a billion and a half people do not have access to electricity. Over the next 50 years, there will be another 3 billion people added to the planet, most of whom will be in the developing world. Clearly, our business objectives are tied to economic growth around the globe. Until basic human needs can be met, it will be a difficult world in which to do business, much less to create new markets and growth opportunities.

WHAT MUST BE DONE TO RAISE THE STANDARD OF LIVING OF THE WORLD'S POOREST COUNTRIES? HOW CAN A COMPANY LIKE CHEVRONTEXACO CONTRIBUTE?

Progress depends on all of us working together in partnership – governments, multilateral organizations, nongovernmental organizations and business. There's a role for each. Governments must do the things only they can do – advocate and practice good governance, provide education and health care, and create a stable investment climate. Multilateral organizations such as the World Bank, the International Monetary Fund and the World Trade Organization should work with governments and help them establish good policies. Nongovernmental organizations

Q & A

must help local populations make sustainable improvements in their economies and be open to working with all stakeholders, including industry. Business, for its part, should be focused on making wise investments, creating jobs and running sound, profitable operations. But it must also work collaboratively with both governmental and nongovernmental organizations to improve the quality of life where it operates.

YOU HAVE SPOKEN OF THE NEED TO ENCOURAGE ENERGY CONSERVATION. WHY WOULD A COMPANY THAT IS IN THE BUSINESS OF SELLING ENERGY GLOBALLY WANT PEOPLE TO USE LESS OF IT?

We are in this business for the long term. If we want to continue to promote economic growth, conservation will help keep energy supplies plentiful and affordable. There are environmental benefits to conservation as well. It may be the single most effective way to reduce greenhouse gas emissions. So its importance cannot be overstated.

CHEVRONTEXACO RECENTLY RECEIVED THE U.S. STATE DEPARTMENT'S CORPORATE EXCELLENCE AWARD FOR ITS LONG-TERM HUMANITARIAN EFFORTS IN NIGERIA. SURELY THAT WAS A PROUD MOMENT.

Absolutely. Our Nigerian operations have a long history of working with local communities to help improve their quality of life. This past year was especially difficult because of civil unrest near our Escravos natural gas terminal on the Niger Delta. Our Nigerian employees not only ensured their own safety and the safety of our facilities, but they also airlifted people in the local community to safety.

DAVE O'REILLY
CHAIRMAN OF THE BOARD
AND CHIEF EXECUTIVE OFFICER

Many of our employees and contractors work under very trying and challenging circumstances. This past year, our Venezuelan employees kept operations running safely despite a national oil strike. Our employees in the Partitioned Neutral Zone between Kuwait and Saudi Arabia also kept operations running smoothly and safely during the Iraqi war. This award is a testament to all the people of ChevronTexaco who work every day to deliver reliable and affordable energy – the right way.

THE REPUTATION OF THE PETROLEUM INDUSTRY CONTINUES TO SUFFER. WHAT CAN BE DONE TO IMPROVE IT?

As an industry, we must continue to improve our collective performance and be responsive to public concerns about the impact of our operations. If we fail to be responsive, our industry's reputation will continue to suffer, and we will continue to be constrained by increased regulations and lack of access to resources. Additionally, it could hinder our efforts to attract talented people to our business. This industry has a powerful and positive story to tell, and we should be neither shy nor apologetic about telling it. We provide the energy that powers the world's economic engines. The energy we produce is essential to improving quality of life, especially in developing countries. That is something to be proud of, and we need to reinforce that message through effective communications.



CHEVRONTEXACO AT A GLANCE

ChevronTexaco Corporation is one of the world's largest integrated energy companies. We have approximately 51,000 employees working in more than 180 countries. Our operations span the spectrum of energy activities, including crude oil and natural gas exploration and production, and the refining, marketing and transportation of petroleum products. We also have significant interests in petrochemicals and power generation assets and are working to develop and commercialize the next generation of promising energy technologies.

GLOBAL UPSTREAM

ChevronTexaco's global upstream business is the linchpin of the company's current and future performance. For the 11th consecutive year, proved crude oil and natural gas replacement exceeded 100 percent. Worldwide net proved crude oil and natural gas reserves were 12 billion barrels of oil-equivalent at the end of 2003. During the year, the company produced 2.5 million barrels per day of oil-equivalent.

We are the top crude oil and natural gas producer in Angola and Kazakhstan and the top crude oil producer in Indonesia. We are one of the largest crude oil and natural gas producers in the United States, West Africa, Asia-Pacific and Latin America.

Our exploration activities are focused on the U.S. Gulf of Mexico, Nigeria and Angola. We are the largest holder of deepwater acreage in Nigeria and among the top in the deepwater Gulf of Mexico. In Australia, we are the largest leaseholder of undeveloped natural gas resources.

GLOBAL GAS

In 2003, ChevronTexaco created a new global natural gas business. Its objective is to accelerate the commercialization of ChevronTexaco's natural gas resources and maximize the value of the company's natural gas portfolio.

With natural gas resources and production in some of the world's most prolific basins, the company will build on its liquefied natural gas (LNG) capabilities, initially targeting North American and Asian markets. The Port Pelican receiving terminal, to be located in the U.S. Gulf of Mexico, will link North American markets with natural gas resources in West Africa and Latin America. Port Pelican is the first offshore facility of its kind to be permitted in the United States. In Asia-Pacific, we are moving forward to commercialize our vast resource base in the Greater Gorgon Area offshore Australia. Global Gas, through its gas-to-liquids (GTL) joint venture, Sasol Chevron, also is developing a GTL project in Nigeria.

Global Gas also has oversight of ChevronTexaco's pipeline, shipping, natural gas marketing, power generation facilities and gasification licensing business.



GLOBAL PORTFOLIO
WORLDWIDE UPSTREAM OPERATIONS

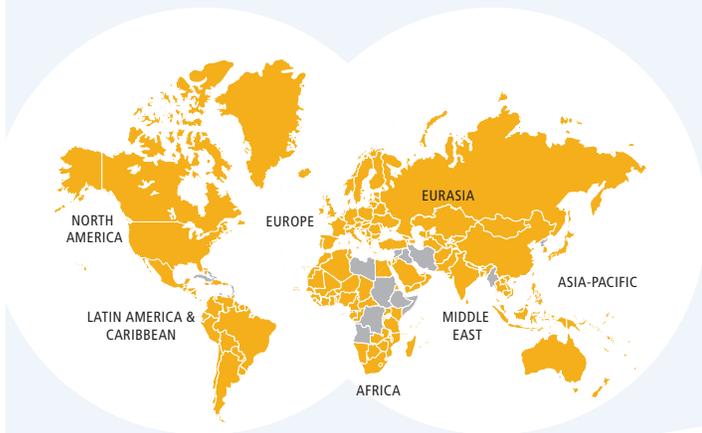
● CHEVRONTEXACO



GLOBAL DOWNSTREAM

ChevronTexaco's downstream businesses refine crude oil and market petroleum products around the world. With 21 wholly owned and affiliated fuel refineries, we processed approximately 2 million barrels of crude oil per day and averaged 3.7 million barrels per day of refined products sales worldwide during 2003. Global Downstream is focused on its areas of strength – the U.S. West Coast, U.S. Gulf Coast, Asia and Latin America. Worldwide, we have strong recognition through our Chevron, Texaco and Caltex motor fuel brands.

ChevronTexaco holds a top three position in almost three-quarters of its markets. We sell our products through a network of more than 24,000 retail stations, including those of affiliate companies. We are a market leader on the U.S. West Coast and in South Korea, Australia, Southeast Asia and the Caribbean.



GLOBAL PORTFOLIO
WORLDWIDE DOWNSTREAM OPERATIONS

 CHEVRONTEXACO

OTHER BUSINESSES

ChevronTexaco, through its 50-50 joint venture Chevron Phillips Chemical Company LLC, is one of the leading manufacturers of petrochemicals. The company has 32 manufacturing facilities in eight countries and markets chemicals products including olefins, polyolefins, aromatics and specialty products.

Chevron Oronite markets more than 500 performance-enhancing products and supplies one-fourth of the world's fuel and lubricant additives. Oronite operates two major global businesses – lubricating oil additives and fuel additives. In 2003, it achieved record sales volumes.

ChevronTexaco's technology companies work together to deploy technologies that enhance our core businesses (Energy Technology Company and Information Technology Company); deliver energy solutions to businesses and public institutions (Chevron Energy Solutions); and provide opportunities in next-generation technology (ChevronTexaco Technology Ventures). ChevronTexaco enhances its technical capabilities through extensive partnerships with technology companies, universities and public agencies throughout the world.

For more information about the businesses of ChevronTexaco, visit our Web site, www.chevrontexaco.com.



ENERGY TERMS

Additives Chemicals to control engine deposits and improve lubricating performance.

Barrels of oil-equivalent (BOE) A unit of measure to quantify crude oil and natural gas amounts using the same basis. Natural gas volumes are converted to barrels on the basis of energy content. See *oil-equivalent gas*.

Condensates Liquid hydrocarbons produced with natural gas, separated by cooling and other means.

Enhanced recovery Techniques used to increase or prolong production from crude oil and natural gas fields.

Exploration Searching for crude oil and/or natural gas by utilizing geologic and topographical studies, geophysical and seismic surveys, and drilling of wells.

Gasification Commercially proven process that converts low-value hydrocarbons into clean synthesis gas.

Gas-to-liquids (GTL) A process that converts natural gas into high-quality transportation fuels.

Greenhouse gases Gases that trap heat in the Earth's atmosphere (e.g., carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride).

Integrated energy company A company engaged in all aspects of the industry: exploring for and producing crude oil and natural gas (*upstream*); refining, marketing and transporting crude oil, natural gas and refined products (*downstream*); manufacturing and distributing petrochemicals (*chemicals*); and generating power.

Liquefied natural gas (LNG) Natural gas that is liquefied under extremely cold temperatures to facilitate storage or transportation in specially designed vessels.

Liquefied petroleum gas (LPG) Light gases, such as butane and propane, that can be maintained as liquids while under pressure.

Natural gas liquids (NGL) Separated from natural gas, these include ethane, propane, butane and natural gasoline.

Oil-equivalent gas (OEG) The volume of natural gas needed to generate the equivalent amount of heat as a barrel of oil (approximately 6,000 cubic feet of natural gas equals one barrel of oil).

Oil sands Naturally occurring mixture of bitumen – a heavy viscous form of crude oil – water, sand and clay. Using hydroprocessing technology, bitumen can be refined to yield synthetic crude oils.

Petrochemicals Derived from petroleum; used principally for the manufacture of chemicals, plastics and resins, synthetic fibers, detergents, adhesives, and synthetic motor oils.

Production *Total production* refers to all the crude oil and natural gas produced from a property. *Gross production* is the company's share of total production before deducting royalties. *Net production* is gross production minus royalties paid to landowners.

Refinery utilization rate Represents average crude oil consumed in fuel and asphalt refineries for the year expressed as a percentage of the refineries' average annual crude unit capacity adjusted for refinery dispositions.

Renewables Energy resources that are not depleted when consumed or converted into other forms of energy (e.g., solar, geothermal, ocean and tide, wind, hydroelectric power, biomass fuels, and hydrogen).

Reserves Crude oil or natural gas contained in underground rock formations called *reservoirs*. *Proved reserves* are the estimated quantities that geologic and engineering data demonstrate can be produced with reasonable certainty from known reservoirs under existing economic and operating conditions. Estimates change as additional information becomes available. *Recoverable reserves* are those that can be produced using all known primary and enhanced recovery methods.

U.S. Securities and Exchange Commission (SEC) rules permit oil and gas companies to disclose only proved reserves in their filings with the SEC. Certain terms, such as "probable," "possible" or "recoverable" reserves, or "resources," may be used to describe certain oil and gas properties in sections of this document that are not filed with the SEC.

FINANCIAL TERMS

Cash flow from operating activities Cash generated from the company's businesses, an indicator of a company's ability to pay dividends and fund capital programs. Excludes cash flows related to the company's financing and investing activities.

Extraordinary item In 2001, the net after-tax effect on income associated with asset dispositions mandated by the U.S. Federal Trade Commission and other assets that were duplicative to the combined company.

Margin The difference between the cost of purchasing, producing or marketing a product and its sales price.

Merger-related expenses The incremental expenses necessary to effect the combination of Chevron and Texaco. The amount shown on the Income Statement is before income tax. Examples are employee termination expenses; professional service fees for investment bankers, attorneys and public accountants; employee and office relocation costs; expenses associated with closure of redundant facilities; and reconfiguration of information technology, telecommunications and accounting systems.

Net income The primary earnings measure for a company, as determined under Generally Accepted Accounting Principles (GAAP), and detailed on a separate financial statement.

Return on capital employed (ROCE) ROCE is calculated by dividing *net income* (adjusted for after-tax interest expense and minority interest) by the average of total debt, minority interest and *stockholders' equity* for the year.

Stockholders' equity The owners' share of the company – the difference between total assets and total liabilities.

Total stockholder return The return to stockholders from stock price appreciation and reinvested dividends for a period of time.

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CAUTIONARY STATEMENTS RELEVANT TO FORWARD-LOOKING INFORMATION FOR THE PURPOSE OF "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This Annual Report of ChevronTexaco Corporation contains forward-looking statements relating to ChevronTexaco's operations that are based on management's current expectations, estimates and projections about the petroleum, chemicals and other energy-related industries. Words such as "anticipates," "expects," "intends," "plans," "targets," "projects," "believes," "seeks," "estimates" and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. You should not place undue reliance on these forward-looking statements, which speak only as of the date of this report. Unless legally required, ChevronTexaco undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Among the factors that could cause actual results to differ materially are crude oil and natural gas prices; refining margins and marketing margins; chemicals prices and competitive conditions affecting supply and demand for aromatics, olefins and additives products; actions of competitors; the competitiveness of alternate energy sources or product substitutes; technological developments; the results of operations and financial condition of equity affiliates; Dynegy Inc.'s ability to successfully complete its recapitalization and restructuring plans; inability or failure of the company's joint-venture partners to fund their share of operations and development activities; potential failure to achieve expected production from existing and future oil and gas development projects; potential delays in the development, construction or start-up of planned projects; potential disruption or interruption of the company's production or manufacturing facilities due to war, accidents, political events, civil unrest or severe weather; potential liability for remedial actions under existing or future environmental regulations and litigation; significant investment or product changes under existing or future environmental regulations (including, particularly, regulations and litigation dealing with gasoline composition and characteristics); potential liability resulting from pending or future litigation; the company's ability to successfully implement the restructuring of its worldwide downstream organization and other business units; the company's ability to sell or dispose of assets or operations as expected; and the effects of changed accounting rules under generally accepted accounting principles promulgated by rule-setting bodies. In addition, such statements could be affected by general domestic and international economic and political conditions. Unpredictable or unknown factors not discussed herein also could have material adverse effects on forward-looking statements.

KEY FINANCIAL RESULTS

Millions of dollars, except per-share amounts	2003	2002	2001
Net Income	\$ 7,230	\$ 1,132	\$ 3,288
Per Share:			
Net Income – Basic	\$ 6.97	\$ 1.07	\$ 3.10
– Diluted	\$ 6.96	\$ 1.07	\$ 3.09
Dividends*	\$ 2.86	\$ 2.80	\$ 2.65
Sales and Other			
Operating Revenues	\$ 120,032	\$98,691	\$ 104,409
Return on:			
Average Capital Employed	15.7%	3.2%	7.8%
Average Stockholders' Equity	21.3%	3.5%	9.8%

*Chevron Corporation dividend pre-merger.

INCOME (LOSS) BY MAJOR OPERATING AREA BEFORE CHANGES IN ACCOUNTING PRINCIPLES

Millions of dollars	2003	2002	2001
Exploration and Production			
United States	\$ 3,183	\$ 1,717	\$ 1,779
International	3,220	2,839	2,533
Total Exploration and Production	6,403	4,556	4,312
Refining, Marketing and Transportation			
United States	482	(398)	1,254
International	685	31	560
Total Refining, Marketing and Transportation	1,167	(367)	1,814
Chemicals	69	86	(128)
All Other	(213)	(3,143)	(2,710)
Income Before Cumulative Effect of Changes in Accounting Principles	\$ 7,426	\$ 1,132	\$ 3,288
Cumulative Effect of Changes in Accounting Principles	(196)	–	–
Net Income*	\$ 7,230	\$ 1,132	\$ 3,288

*Includes Foreign Currency (Losses) Gains: \$ (404) \$ (43) \$ 191

Net income includes net charges of \$196 million for the cumulative effect of changes in accounting principles, primarily \$200 million for the adoption on January 1, 2003, of the Financial Accounting Standards Board Statement No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). Refer to Note 25 to the Consolidated Financial Statements on page 74 for additional discussion. Also in the first quarter of 2003, the company recorded an after-tax gain of \$4 million for its share of its affiliate Dynegy's cumulative effect of adoption of Emerging Issues Task Force Consensus No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," effective January 1, 2003.

Net income in each period presented includes amounts for matters that management characterizes as "special items," as described in the following table.

SPECIAL ITEMS

Millions of dollars – Income (loss)	2003	2002	2001
Dynegy-Related	\$ 325	\$(2,306)	\$ –
Asset Dispositions	122	–	49
Tax Adjustments	118	60	(5)
Asset Impairments and Revaluations	(340)	(485)	(1,709)
Restructuring and Reorganizations	(146)	–	–
Environmental Remediation			
Provisions	(132)	(160)	(78)
Merger-Related Expenses	–	(386)	(1,136)
Litigation Provisions	–	(57)	–
Extraordinary Loss on			
Merger-Related Asset Sales	–	–	(643)
Total Special Items	\$ (53)	\$(3,334)	\$(3,522)

Because of their nature and amount, these special items are identified separately to help explain the changes in net income and segment income between periods, as well as to help distinguish the underlying trends for the company's core businesses. Special items are discussed in detail for each major operating area in the "Results of Operations" section beginning on page 30. "Restructuring and Reorganizations" is described in detail in Note 12 to the Consolidated Financial Statements on page 61. The categories "Merger-Related Expenses" and "Extraordinary Loss on Merger-Related Asset Sales" are described in detail in the "Texaco Merger Transaction" section on page 29.

BUSINESS ENVIRONMENT AND OUTLOOK

As shown in the "Special Items" table, large net special-item charges adversely affected net income in 2002 and 2001. In 2002, \$2.3 billion of the \$3.3 billion of net charges related to the company's investment in its Dynegy Inc. affiliate. Refer to pages 34 and 35 for a discussion of these matters. Approximately one-half of the \$3.5 billion of net charges in 2001 related to asset impairments, primarily the result of downward revisions to crude oil and natural gas reserve quantities.

Apart from the effects of special items, ChevronTexaco's earnings depend largely on the profitability of its business segments in upstream – exploration and production – and downstream – refining, marketing and transportation. Overall earnings trends are typically less affected by results from the company's commodity chemicals segment and other investments.

The company's long-term competitive position, particularly given the capital-intensive and commodity-based nature of the industry, is closely associated with the company's ability to invest in projects that provide adequate financial returns and to manage operating expenses effectively. The company also continuously evaluates opportunities to dispose of assets that are not key to providing long-term value, or to acquire assets or operations complementary to its asset base to help sustain the company's growth. In addition to the asset-disposition and restructuring plans announced in 2003, other such plans may occur in future periods and result in significant gains or losses. Refer to the "Operating Developments" section on pages 28 and 29 for a discussion that includes references to the company's asset disposition activities.

Comments related to earnings trends for the company's major business areas are as follows:

Upstream Year-to-year changes in exploration and production earnings align most closely with industry price levels for crude oil and natural gas. Crude oil and natural gas prices are subject to certain external factors over which the company has no control, including product demand connected with global economic conditions, industry inventory levels, production quotas imposed by the Organization of Petroleum Exporting Countries (OPEC), weather-related damages and disruptions, competing fuel prices and regional supply interruptions that may be caused by military conflicts, civil unrest or political uncertainties. The company monitors developments closely in the countries in which it operates.

Longer-term trends in earnings for this segment are also a function of other factors besides price fluctuations, including changes in the company's oil and gas production levels and the company's ability to find or acquire and efficiently produce crude oil and natural gas reserves. Most of the company's overall capital investment is in its upstream businesses, particularly outside the United States. Refer to the "Capital and Exploratory Expenditures" on pages 35 and 36 for discussion of the types of upstream investments targeted for 2004. Investments in upstream projects oftentimes are made well in advance of the start of the associated crude oil and natural gas production.

Industry price levels for crude oil in early 2003 reached a 12-year high, reaching a peak of about \$38 per barrel. Prices for West Texas Intermediate (WTI), a benchmark crude, then averaged about \$31 for the year, an increase of about \$5 from 2002. The WTI spot prices at the end of December 2003 and at the end of February 2004 were about \$32 and \$36, respectively. Among other things, these relatively high industry prices reflected increased demand from improved economies in many countries and continued production curtailments by OPEC.

CRUDE OIL PRICES 1986 THROUGH 2003

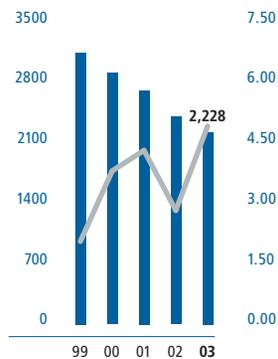
Dollars per barrel



The average spot price of West Texas Intermediate, a benchmark crude oil, rose 19 percent between 2002 and 2003 and remained above \$30 per barrel in early 2004.

Natural gas prices were also higher in 2003 than in 2002. Benchmark prices for Henry Hub U.S. natural gas averaged more than \$5 per thousand cubic feet in 2003, versus about \$3 in 2002. The 2003 year-end price was nearly \$6 per thousand cubic feet, about a dollar higher than the year-earlier level. Prices in the United States are typically highest during the winter period, when demand for heating fuel is greatest. At the end of February 2004, the U.S. benchmark price was about \$5 per thousand cubic feet. The trend toward higher U.S. natural gas prices is mainly the result of overall demand based upon the strength of the

U.S. NATURAL GAS PRICES & PRODUCTION

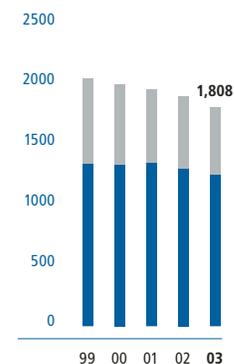


■ Prices in Dollars per Thousand Cubic Feet (right scale)
■ Production in Millions of Cubic Feet per Day (left scale)

Average prices climbed more than 70 percent during 2003. Production was down more than 7 percent due to normal field declines and production not restored after 2002 storm damage to facilities in the Gulf of Mexico.

NET CRUDE OIL & NATURAL GAS LIQUIDS PRODUCTION*

Thousands of barrels per day



■ United States
■ International

Net liquids production declined about 5 percent in 2003, primarily the result of normal field declines in the United States.

*Includes equity in affiliates

economy and the declining levels of industry reserves and production in the United States.

Partially offsetting the benefit of higher crude oil and natural gas prices in 2003 was a 4 percent decline in the company's worldwide oil-equivalent production from the prior year. The decrease was largely the result of lower production in the United States due to normal field declines and production deemed uneconomic to restore following storm damages in the Gulf of Mexico in the second half of 2002. International oil-equivalent production was also down slightly – primarily the result of lower liquids production in the company's Indonesian operations. The reduced net production in Indonesia was mainly due to the effect of higher prices on cost-oil recovery volumes under production-sharing arrangements and the expiration of a production-sharing agreement in the third quarter 2002.

The company's oil-equivalent production level in future periods is uncertain, in part because of production quotas set by OPEC and the potential for production disruptions from civil unrest and changing geopolitics in the countries in which the company operates and holds interests. Twenty-two percent of the company's net oil equivalent production in 2003 was in the OPEC-member countries of Indonesia, Nigeria and Venezuela and in the Partitioned Neutral Zone between Saudi Arabia and Kuwait. Although the company's production levels in these areas were not constrained in 2003 by OPEC quotas, future production could be affected by OPEC-imposed limitations. In Nigeria, about 45,000 barrels per day of the company's net production capacity has been shut-in in certain onshore areas since March 2003 because of security concerns. The company expects to re-enter this area during 2004 to begin repairing damaged equipment. OPEC production constraints could possibly limit the eventual resumption of a portion or all of this production.

Downstream Refining, marketing and transportation earnings are closely tied to regional supply and demand for refined products and the associated effects on industry refining and marketing margins. The company's core marketing areas are the western and southeastern United States, western Canada, the Asia-Pacific, northern Europe, Africa and Latin America.

Company-specific factors influencing the company's profitability in this segment include the operating efficiencies of the refinery network, including any downtime due to planned maintenance, refinery upgrade projects or operating incidents.

Downstream earnings improved in 2003, compared with the prior year, on higher refined product margins in most of the company's operating areas. In contrast, margins in the 2002 period were at their lowest levels since the mid-1990s, as weak market conditions did not allow rising feedstock costs to be fully recovered from consumers of refined products. Industry margins may be volatile in the future, depending primarily on price movements for crude oil feedstocks, the strength of the economies in which the company operates and other factors.

Chemicals Earnings of \$69 million in 2003 were lower than the year-ago period. Depressed earnings in both years reflected excess-supply conditions for the commodity chemicals industry that have kept product margins at low levels for a protracted period. A significant improvement in earnings is not expected in the near future.

OPERATING DEVELOPMENTS

Key operating developments and events during 2003 and early 2004 included:

Upstream

Worldwide Oil and Gas Reserves Approximately 1 billion barrels of oil-equivalent reserves were added during 2003, including sales and acquisitions. These additions equated to 108 percent of production for the year. Of the 1 billion barrels added, nearly 300 million were the result of discoveries and extensions, including almost 200 million in the United States. Contract extensions in Colombia and Denmark accounted for approximately 200 million additional barrels. About 100 million barrels were added through improved

recovery techniques, primarily in Indonesia and the United States. Finally, the largest revisions resulted from reservoir studies and analyses in Kazakhstan, increasing reserves 300 million barrels.

North America Plans were initiated to improve the competitive performance and operating efficiency of the company's North America exploration and production portfolio. These plans include the sale of certain nonstrategic producing properties and royalty interests in the United States and possibly western Canada. The company expects to retain about 400 core fields. Additionally, the company expects to consolidate certain business functions and office locations.

In late 2003, four new deepwater discoveries in the Gulf of Mexico – Perseus, Sturgis, Tubular Bells and Saint Malo – were announced.

ChevronTexaco is the operator and holds a 50 percent working interest in both the Perseus and Sturgis prospects. In the non-operated discoveries, the company holds a 30 percent interest in Tubular Bells and a 12.5 percent interest in Saint Malo. Additionally at the Blind Faith discovery, an agreement was reached to assume operatorship and increase the company's working interest to 50 percent.

At the Tahiti prospect, a major discovery in the deepwater Gulf of Mexico, appraisal drilling validated the presence of high-quality reservoir sand. ChevronTexaco is the operator of the prospect and has a 58 percent working interest.

In late 2003, an appraisal well was drilled at the Great White discovery, a nonoperated exploratory opportunity in the western Gulf of Mexico. The company has a 33 percent working interest in this prospect.

Australia A well was drilled during 2003 in the Io-Jansz natural gas field, off the northwest coast of Western Australia. Test results provided verification of the field's extensive production potential. ChevronTexaco holds a 50 percent equity interest in the WA-18-R permit area.

Nigeria In October 2003, successful results were announced from the Aparo-3 appraisal well and the Nsiko-1 wildcat well in deepwater Block OPL-249, where the company is entitled to a variable equity interest over the life of the field. In addition, the company announced a significant extension of its 30 percent-owned Usan Field discovery. The drilling of the Usan-4 appraisal well, located in deepwater Block OPL-222, confirmed the presence of commercial quantities of oil as well as additional potential in previously untested reservoirs. In early 2003, the company announced a gas discovery in the 46 percent-owned deepwater Block OPL-218, following completion of the Nnwa-2 appraisal well.

Earlier in the year, the company and its partners reached an agreement that will govern future operations in the offshore Block OPL-216 concession. The agreement is expected to enable the continued advancement of plans to develop the Agbami Field. The company has varying funding obligations and profit entitlement for the Block OPL-216 development according to the terms of two production-sharing contracts in the concession.

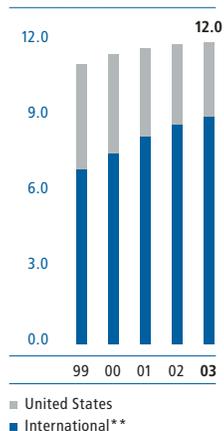
Angola Major contracts were awarded for the first phase of development in the Benguela, Belize, Lobito and Tomboco fields in deepwater Block 14. The first phase will involve the drilling and completion of more than 30 development wells in the Benguela and Belize fields and the construction and installation of drilling and production facilities that will form a new production hub in Block 14. The company is the operator and holds a 31 percent interest in Block 14.

Chad/Cameroon The company's first cargo of crude oil from fields in southern Chad was loaded at facilities offshore Cameroon for export to world markets in late 2003. The crude oil produced in Chad is transported more than 600 miles by pipeline to a floating storage and offloading vessel located several miles offshore. Full production capacity of 225,000 barrels per day is expected to be reached in mid-2004. ChevronTexaco holds a 25 percent equity interest in the Chad-Cameroon upstream operation and about a 23 percent interest in the pipeline.

Kazakhstan The company's 50 percent-owned affiliate, Tengizchevroil (TCO) reached an agreement with the government of Kazakhstan in the third quarter of 2003 to expand operations

NET PROVED RESERVES

Billions of BOE*



Net proved reserves additions in 2003 equaled 108 percent of oil-equivalent production for the period. This was the 11th consecutive year that reserve additions exceeded 100 percent of production.

*Barrels of oil-equivalent
**Includes equity in affiliates

at the Tengiz and Korolev fields. The Sour Gas Injection/Second Generation project is expected to increase TCO's oil production capacity from 285,000 barrels per day to between 430,000 and 500,000 barrels per day in the second half of 2006. Also, a 400-mile pipeline was completed that will enable production from the Karachaganak Field to be exported to world markets via the Caspian Pipeline when fully operational in mid-2004.

Colombia An agreement was reached that extends the company's production rights in northern natural gas fields. Under the contract extension, ChevronTexaco holds a 43 percent interest with the remaining 57 percent held by the country's national petroleum company.

Venezuela ChevronTexaco was awarded the license for the 60 percent-owned and -operated Block 2 Plataforma Deltana, a prospective natural gas region in Venezuela's Atlantic continental shelf.

Global Natural Gas Projects In the Gulf of Mexico, the company's permit application was approved for plans to develop the Port Pelican deepwater LNG facility. The company also filed permits for the construction of an LNG receiving and regasification terminal offshore Baja California, Mexico.

In September 2003, the Gorgon Joint Venture, in which the company is a 57 percent owner, received in-principle approval from the Western Australian government through an act of parliament to proceed with plans to construct a natural gas processing facility on Barrow Island. The decision represented a significant milestone in the company's plans to commercialize its large Gorgon natural gas resource base. Also in 2003, the Gorgon Joint Venture announced an agreement with the China National Offshore Oil Corporation (CNOOC) in October to negotiate the sale of Gorgon liquefied natural gas to the People's Republic of China. The agreement, which is subject to the completion of formal contracts, enables CNOOC to purchase an interest in the Gorgon gas development project and to facilitate the sale of LNG into the Chinese market.

In Nigeria, the company and its partners in the Brass River Consortium agreed to advance plans for the front-end engineering and design work for a new LNG facility at Brass River. The studies are expected to be completed in 2004.

A new U.S. wholesale natural gas marketing unit became fully operational in April 2003. This business unit was established following a decision by the company's Dynegy affiliate to exit the natural gas marketing and trading business. ChevronTexaco's natural gas sale and purchase agreements with Dynegy were terminated at the end of January 2003.

Downstream

The company initiated a major restructuring of its global refining, marketing, and supply and trading organizations in order to lower costs, improve efficiency and achieve sustained improvements in its financial performance relative to competitors. The organization was changed from a geographical to a global functional alignment and was implemented at the beginning of 2004.

Downstream asset dispositions, including the sale of the El Paso, Texas, refinery and approximately 400 service stations in various markets, were completed in 2003 to improve returns by focusing investment in areas with the strongest long-term growth and returns.

Facility upgrade projects at refineries in Pascagoula, Mississippi; Pembroke, United Kingdom; and Rotterdam, Netherlands were completed, resulting in increased product yields and enabling the manufacture of low-sulfur fuels. In the Philippines, the Batangas Refinery was converted into a finished-product terminal.

Chemicals

In Qatar, a new olefins and polyolefins complex was commissioned in 2003. The complex is owned and operated through a joint venture between the company's 50 percent-owned equity affiliate, Chevron Phillips Chemical Company (CPChem), and Qatar General Petroleum. CPChem holds a 49 percent interest in the joint venture.

TEXACO MERGER TRANSACTION

Basis of Presentation In October 2001, Texaco Inc. (Texaco) became a wholly owned subsidiary of Chevron Corporation (Chevron) pursuant to a merger transaction, and Chevron changed its name to ChevronTexaco Corporation. Certain operations that were jointly owned by the combining companies are consolidated in the accompanying financial statements. These operations are primarily those of the Caltex Group of Companies, which was previously owned 50 percent each by Chevron and Texaco. The combination was accounted for as a pooling of interests, and the accompanying audited consolidated financial statements for all periods are presented as if Chevron and Texaco had always been combined.

Merger Effects Under mandate of the Federal Trade Commission (FTC) as a condition to its approval of the merger, the company sold its interests in Equilon and Motiva – joint ventures engaged in U.S. downstream businesses – in February 2002, resulting in cash proceeds of \$2.2 billion. Indemnification by ChevronTexaco against certain Equilon and Motiva contingent liabilities at the date of sale are discussed in the "Guarantees, Off-Balance-Sheet Arrangements and Contractual Obligations, and Other Contingencies" section beginning on page 37. Other mandated asset dispositions were also completed during 2002. Net income and cash proceeds from these other asset sales were not material. All such assets sold as a result of the merger provided net income of approximately \$375 million in 2001. The net loss on assets sold under the FTC mandate is presented in the 2001 income statement as an extraordinary item.

The company incurred before-tax merger-related expenses of approximately \$1.6 billion (\$1.1 billion after tax) and \$576 million (\$386 million after tax) in 2001 and 2002, respectively. Major expenses included employee severance payments; incremental pension and medical plan benefit costs associated with workforce reductions; legal, accounting, Securities and Exchange Commission (SEC) filing and investment banker fees; employee and office relocations; and costs for the elimination of redundant facilities and operations. No significant merger-related expenses occurred in 2003.

RESULTS OF OPERATIONS

Major Business Areas The following section presents the results of operations for the company's business segments, as well as for the departments and companies managed at the corporate level. To aid in the understanding of changes in segment income between periods, the discussion is in two parts – first, relating to the underlying operational trends and second, with respect to special items that tended to obscure the underlying trends. In the following discussions, the term “earnings” is defined as net income or segment income, before the cumulative effect of changes in accounting principles.

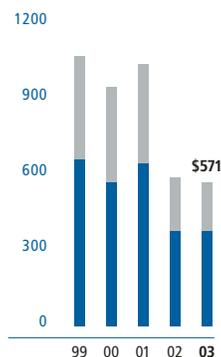
U.S. Exploration and Production

Millions of dollars	2003	2002	2001
Income Before Cumulative Effect of Change in Accounting Principle	\$ 3,183	\$ 1,717	\$ 1,779
Cumulative Effect of Accounting Change	(350)	–	–
Segment Income	\$ 2,833	\$ 1,717	\$ 1,779
<i>Special Items Included in Segment Income:</i>			
Asset Dispositions	\$ 77	\$ –	\$ 49
Asset Impairments and Revaluations	(103)	(183)	(1,168)
Restructuring and Reorganizations	(38)	–	–
Environmental Remediation Provisions	–	(31)	–
Tax Adjustments	–	–	8
Total Special Items	\$ (64)	\$ (214)	\$(1,111)

The improvement in 2003 segment income from 2002 primarily was the result of higher prices for crude oil and natural gas. Partially offsetting this effect was a decline in oil-equivalent production. The change between 2001 and 2002 reflected signifi-

EXPLORATION EXPENSES

Millions of dollars

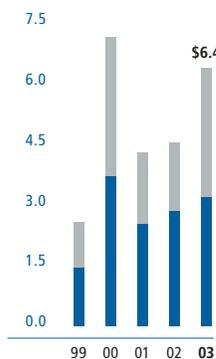


■ United States
■ International

Exploration expenses declined after the October 2001 merger, reflecting, in part, the high-grading of the combined exploration portfolio.

WORLDWIDE EXPLORATION & PRODUCTION EARNINGS*

Billions of dollars



■ United States
■ International

Earnings increased significantly in 2003 on higher prices for crude oil and natural gas. Partially offsetting were the effects of lower production and foreign currency losses.

*Before the cumulative effect of changes in accounting principles

cantly lower natural gas realizations and lower production in the 2002 period.

The company's average 2003 U.S. liquids realization was \$26.66 per barrel, compared with \$21.34 in 2002 and essentially the same in 2001. The average natural gas realization was \$5.01 per thousand cubic feet in 2003, compared with \$2.89 and \$4.38 in 2002 and 2001, respectively.

Net oil-equivalent production averaged 933,000 barrels per day in 2003, down 7 percent from 2002 and 12 percent from 2001. The net liquids component for 2003 averaged 562,000 barrels per day, a decline of 7 percent from 2002 and 8 percent from 2001. Net natural gas production averaged 2.228 billion cubic feet per day in 2003, 7 percent lower than 2002 and 18 percent lower than 2001. The oil-equivalent production decline in 2003 was associated mainly with normal field declines and the absence of about 10,000 to 15,000 barrels per day of production the company deemed uneconomic to restore following storm damages in the Gulf of Mexico in late 2002. The storms reduced the company's 2002 oil-equivalent production by about 20,000 barrels per day.

Net special-item charges of \$64 million in 2003 reflected asset impairments of \$103 million – associated mainly with the write-down of assets in anticipation of sale – and restructuring and reorganization charges of \$38 million, which mainly were associated with employee severance costs. Offsetting a portion of these charges were gains of \$77 million from asset sales. Special items in 2002 and 2001 included asset impairments caused by write-downs in proved oil and gas reserve quantities for a number of fields. The amount in 2001 related primarily to the Midway Sunset Field in California's San Joaquin Valley, after the determination that lower-than-projected heavy oil recovery would result from the steam-injection process.

International Exploration and Production

Millions of dollars	2003	2002	2001
Income Before Cumulative Effect of Change in Accounting Principle*	\$ 3,220	\$ 2,839	\$ 2,533
Cumulative Effect of Accounting Change	145	–	–
Segment Income	\$ 3,365	\$ 2,839	\$ 2,533
*Includes Foreign Currency (Losses) Gains:	\$(319)	\$90	\$181
<i>Special Items Included in Segment Income:</i>			
Asset Dispositions	\$ 32	\$ –	\$ –
Asset Impairments and Revaluations	(30)	(100)	(247)
Restructuring and Reorganizations	(22)	–	–
Tax Adjustments	118	(37)	(125)
Total Special Items	\$ 98	\$ (137)	\$(372)

The earnings improvement from 2002 to 2003 included the benefit of higher crude oil and natural gas prices. Partially offsetting the improvements were the effects of lower oil-equivalent production and an unfavorable swing in foreign currency effects. Net foreign currency losses of \$319 million in 2003 primarily related to a significant weakening of the U.S. dollar against the currencies of Canada, Australia and the United Kingdom. Earnings improvement in 2002 vs. 2001 were marginally affected by

a combination of factors, including benefits from higher liquids realizations, higher natural gas production, and lower exploration and income tax expenses, which were offset in part by the effects of lower liquids production, lower natural gas realizations and higher depreciation expense.

The average liquids realization, including equity affiliates, was \$26.79 per barrel in 2003, compared with \$23.06 in 2002 and \$22.17 in 2001. The average natural gas realization was \$2.64 per thousand cubic feet in 2003, compared with \$2.14 in 2002 and \$2.36 in 2001.

Daily net liquids production of 1.246 million barrels in 2003 decreased about 4 percent from 1.295 million barrels in 2002 and about 7 percent from 1.345 million barrels in 2001. The 2003 production decline included about 29,000 barrels per day in Indonesia, related primarily to the effect of lower cost-oil recovery volumes under production-sharing terms during 2003, and the expiration of a production-sharing arrangement in the third quarter 2002. New production occurred in Chad in 2003 and higher volumes were produced in the United Kingdom and Venezuela. The 2002 production decline from the prior year included lower output in Indonesia, primarily due to changes in contractual terms, and in Nigeria, which was mainly associated with OPEC constraints. These effects were partially offset by increased production in Kazakhstan.

Net natural gas production of 2.064 billion cubic feet per day in 2003 was up 5 percent from 2002 and more than 20 percent from 2001. During 2003, output was higher in Australia, Kazakhstan, the Philippines and the United Kingdom. In 2002, areas with production increases from 2001 included the Philippines, Kazakhstan, Nigeria and Australia.

Special items in 2003 were composed of benefits totaling \$150 million related to income taxes and property sales, partially offset by asset impairments and charges for employee termination costs. In 2002, special items included asset impairments connected with write-downs in quantities of proved oil and gas reserves for fields in Africa and Canada. In 2001, special items included a \$247 million impairment of the LL-652 Field in Venezuela.

U.S. Refining, Marketing and Transportation

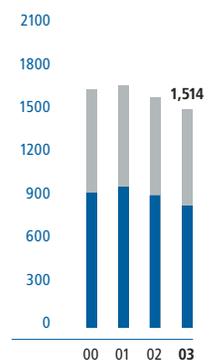
Millions of dollars	2003	2002	2001
Segment Income (Loss)	\$ 482	\$ (398)	\$ 1,254
<i>Special Items Included in Segment Income:</i>			
Asset Dispositions	\$ 37	\$ -	\$ -
Asset Impairments and Revaluations	-	(66)	-
Environmental Remediation Provisions	(132)	(92)	(78)
Restructuring and Reorganizations	(28)	-	-
Litigation Provisions	-	(57)	-
Total Special Items	\$ (123)	\$ (215)	\$ (78)

The U.S. refining, marketing and transportation earnings in 2003 reflected primarily a recovery in industry margins for refined products, especially on the West Coast. Margins in 2002 were very depressed and at one point, hovered near their 12-year lows. Results for 2001 included earnings of \$375 million associated with assets that were later sold as a condition of the merger, which included the company's Equilon and Motiva joint ventures.

Sales volumes for refined products of 1.514 million barrels per day in 2003 decreased about 5 percent from 2002. Demand was weaker for branded gasoline, diesel and jet fuels, and there were lower sales under certain supply contracts. Branded gasoline sales volumes of 557,000 barrels per day were 4 percent lower than 2002. In 2002, branded gasoline sales increased approxi-

U.S. GASOLINE & OTHER REFINED PRODUCTS SALES*

Thousands of barrels per day



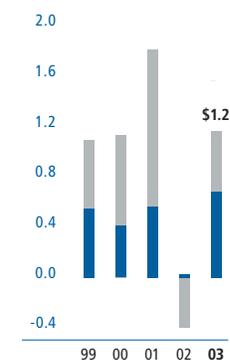
■ Gasoline
■ Other Refined Products Sales

Refined products sales volumes decreased about 5 percent from 2002. The decline partially reflected the August 2003 sale of the El Paso, Texas, refinery.

*Includes equity in affiliates

WORLDWIDE REFINING, MARKETING & TRANSPORTATION EARNINGS

Billions of dollars



■ United States
■ International

U.S. downstream earnings in 2003 rebounded from a loss in 2002, primarily due to a recovery in the industry margins for refined products.

mately 4 percent compared with 2001 volumes. The average U.S. refined products sales realization of \$39.93 per barrel in 2003 was up from the average of \$32.63 per barrel and \$36.26 per barrel in 2002 and 2001, respectively.

Special items in 2003 included \$160 million for reserves for environmental remediation and employee severance costs associated with the global downstream restructuring and reorganization. These charges were partially offset by gains primarily from the sale of service stations. In 2002, special items included environmental remediation provisions and asset write-downs for certain refining and marketing assets, and a litigation charge.

International Refining, Marketing and Transportation

Millions of dollars	2003	2002	2001
Segment Income*	\$ 685	\$ 31	\$ 560
*Includes Foreign Currency (Losses) Gains:	\$ (141)	\$ (176)	\$ 23
<i>Special Items Included in Segment Income:</i>			
Asset Dispositions	\$ (24)	\$ -	\$ -
Asset Impairments and Revaluations	(123)	(136)	(46)
Restructuring and Reorganizations	(42)	-	-
Tax Adjustments	-	-	8
Total Special Items	\$ (189)	\$ (136)	\$ (38)

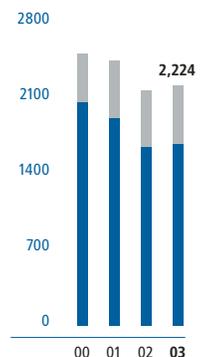
The international refining, marketing and transportation segment includes the company's consolidated refining and marketing businesses, international marine operations, international supply and trading activities, and equity earnings of affiliates, primarily in the Asia-Pacific region.

As in the United States, the international downstream earnings increased on improved refined-product margins for the industry. The decline in earnings from 2001 to 2002 reflected not only the trend in refined product margins but also about a \$200 million unfavorable shift in foreign currency effects between periods.

Total international refined products sales volumes were 2.224 million barrels per day in 2003, up about 2 percent from 2.175 million in 2002 and about 9 percent lower than 2.454 million in 2001. Weak economic conditions dampened demand in 2002.

INTERNATIONAL GASOLINE & OTHER REFINED PRODUCTS SALES*

Thousands of barrels per day



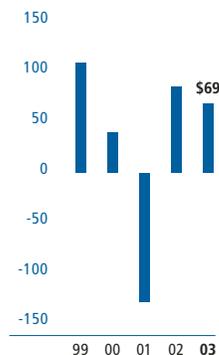
■ Gasoline
■ Other Refined Products Sales

Refined products sales volumes increased about 2 percent from 2002.

*Includes equity in affiliates

WORLDWIDE CHEMICALS EARNINGS*

Millions of dollars



Protracted weak demand for commodity chemicals and industry oversupply continue to suppress chemical earnings.

*Includes equity in affiliates

Special items of \$189 million in 2003 included charges for the write-down of the Batangas Refinery in the Philippines in advance of its conversion to a product terminal facility and employee severance benefits associated with the global downstream restructuring and reorganization. In addition, special charges of \$70 million were recognized for the impairment of assets in anticipation of their sale and the company's share of losses from an asset sale and asset impairment by an equity affiliate. The special item in 2002 was for a write-down of the company's investment in its publicly traded Caltex Australia Limited affiliate to its estimated fair value.

Chemicals

Millions of dollars	2003	2002	2001
Segment Income (Loss)*	\$ 69	\$ 86	\$ (128)
*Includes Foreign Currency Gains (Losses):	\$ 13	\$ 3	\$ (3)
<i>Special Items Included in Segment Income:</i>			
Asset Impairments and Revaluations	\$ -	\$ -	\$ (96)

Chemicals includes the company's Oronite division and equity earnings from the company's 50 percent-owned Chevron Phillips Chemical Company LLC (CPCChem) affiliate. Protracted weak demand for commodity chemicals and industry oversupply conditions continued to suppress earnings for this sector. Special items in 2001 included write-downs of the CPCChem Puerto Rico operations.

All Other

Millions of dollars	2003	2002	2001
Charges Before Cumulative Effect of Change in Accounting Principles*	\$ (213)	\$ (3,143)	\$ (2,710)
Cumulative Effect of Accounting Changes	9	-	-
Segment Charges*	\$ (204)	\$ (3,143)	\$ (2,710)
*Includes Foreign Currency Gains (Losses):	\$ 43	\$ 40	\$ (10)
<i>Special Items Included in Segment Charges:</i>			
Dynegy-Related	\$ 325	\$ (2,306)	\$ -
Asset Impairments and Revaluations	(84)	-	(152)
Restructuring and Reorganizations	(16)	-	-
Tax Adjustments	-	97	104
Environmental Remediation Provisions	-	(37)	-
Merger-Related Expenses	-	(386)	(1,136)
Extraordinary Loss on Merger-Related Asset Sales	-	-	(643)
Total Special Items	\$ 225	\$ (2,632)	\$ (1,827)

All Other consists of the company's interest in Dynegy, coal mining operations, power and gasification businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, and technology companies.

The change in net charges between 2002 and 2003 was largely attributable to the differences in the effects of special items. The 2003 period also included lower interest expense and other corporate charges compared with 2002. Aside from the effect of special items between 2001 and 2002, the net change also reflected lower corporate charges and net interest expense, as well as an increase in favorable tax adjustments of \$245 million.

Special items in 2003 included a benefit of \$365 million from the exchange of the company's investment in Dynegy preferred stock for cash and other Dynegy securities. This benefit was partially offset by charges for asset write-downs of \$84 million, primarily in the gasification business; \$40 million for the company's share of an asset impairment by Dynegy; and employee severance costs of \$16 million.

Special items in 2002 included \$2.3 billion related to Dynegy, composed of \$1.6 billion for the write-down of the company's investment in Dynegy common and preferred stock to its estimated fair value and \$680 million for the company's share of Dynegy's own special items for asset write-downs and revaluations and a loss on an asset sale. Refer also to pages 34 and 35 for "Information Relating to the Company's Investment in Dynegy."

Refer to "Texaco Merger Transaction" on page 29 for information related to special items in 2001 for "Merger-Related Expenses" and "Extraordinary Loss from Merger-Related Asset Sales."

Consolidated Statement of Income In the following table, amounts for special items by income statement category are shown in order to assist in the explanation of changes in those categories between periods. In addition to the effects of special items shown in the table, separately disclosed on the face of the Consolidated Income Statement are a 2003 gain from the exchange of Dynegy Inc. securities, merger-related expenses,

write-down of investments in Dynegy Inc., the cumulative effect of changes in accounting principles and the extraordinary after-tax loss on the sale of assets mandated as a condition of the merger. These matters are discussed elsewhere in the MD&A and in Notes 2 and 14 to the Consolidated Financial Statements on pages 54 and 62.

Millions of dollars	2003	2002	2001
Income (loss) from equity affiliates	\$ 1,029	\$ (25)	\$ 1,144
Memo: Special gains (charges), before tax	179	(829)	(123)
Other income	\$ 335	247	692
Memo: Special gains, before tax	217	–	84
Operating expenses	\$ 8,553	\$ 7,848	\$ 7,650
Memo: Special charges, before tax	329	259	25
Selling, general and administrative expenses	\$ 4,440	\$ 4,155	\$ 3,984
Memo: Special charges, before tax	146	180	139
Depreciation, depletion and amortization	\$ 5,384	\$ 5,231	\$ 7,059
Memo: Special charges, before tax	286	298	2,294
Interest and debt expense	\$ 474	\$ 565	\$ 833
Memo: Special charges, before tax	–	–	–
Taxes other than on income	\$ 17,906	\$ 16,689	\$ 15,156
Memo: Special charges, before tax	–	–	12
Income tax expense	\$ 5,344	\$ 3,024	\$ 4,360
Memo: Special benefits	(312)	(604)	(1,193)

Explanations follow for variations between years for the amounts in the table above – after consideration of the effects of special items – as well as for other income statement categories. Refer to the preceding segment discussions in this section for information relating to special items.

Sales and other operating revenues were \$120 billion in 2003, compared with \$99 billion in 2002 and \$104 billion in 2001. Revenues increased in 2003 primarily from significantly higher prices for crude oil, natural gas and refined products worldwide.

Total sales and operating revenues in 2002 declined from 2001 due to lower average realizations for crude oil and refined products, as well as lower prices and sales volumes for natural gas in the United States.

Income (loss) from equity affiliates increased in 2003, as earnings improved for a number of affiliates, including Tengiz-chevroil, LG-Caltex and CPChem. In 2001, income from equity affiliates included earnings from assets subsequently sold as a condition of the merger.

Other income in 2003 reflected significantly higher foreign currency losses. Likewise, foreign currency effects largely contributed to lower “Other income” in 2002 vs. 2001. Foreign currency losses in 2003 – excluding foreign currency gains or losses of affiliates which are included in “Income (loss) from equity affiliates” – were \$199 million, compared with a loss of \$5 million and a gain of \$121 million in 2002 and 2001, respectively. In 2003, losses resulted primarily from the weakening of the U.S. dollar against the currencies of Canada, Australia and the United Kingdom. In 2002, foreign currency losses related to currencies of most countries in which the company has sig-

nificant operations appreciating against the U.S. dollar. Other income in 2002 also reflected lower interest income.

Purchased crude oil and products costs of \$72 billion in 2003 increased about 25 percent from 2002. The increase was the result of significantly higher prices for crude oil, natural gas and refined products. Crude oil and products purchase costs decreased about 5 percent in 2002, primarily due to lower natural gas prices and reduced natural gas volumes.

Operating, selling, general and administrative expenses of \$13 billion increased from \$12 billion in 2002. About \$800 million of the increase in 2003 resulted from higher freight rates from international shipping operations and higher costs of employee pension plans and other employee-benefit expenses. During 2002, operating, selling, general and administrative expenses increased approximately \$95 million from 2001, primarily from higher pension expense, payroll and other employee-benefit costs. Refer to Note 21, “Employee Benefit Plans,” beginning on page 66 for discussion of the costs associated with the company’s pension plans and other employee benefits in the comparative periods.

Exploration expenses were \$571 million in 2003, \$591 million in 2002 and \$1 billion in 2001. Well write-offs were higher in 2001 than in the other comparative periods.

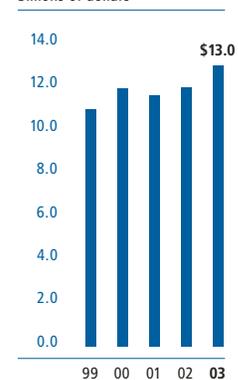
Depreciation, depletion and amortization expenses did not change materially for the reporting periods after consideration of the effects from special items.

Merger-related expenses were \$576 million and approximately \$1.6 billion in 2002 and 2001, respectively. No merger-related expenses were recorded in 2003, reflecting the completion of merger integration activities in 2002.

Taxes other than on income were \$17.9 billion, \$16.7 billion and \$15.2 billion in 2003, 2002 and 2001, respectively. The increase in 2003 primarily reflected the weakening U.S. dollar in 2003 on foreign-currency-denominated duties in the company’s European downstream operations. In 2002, the increase between periods resulted from higher sales volumes in the United Kingdom along with currency effects of a weaker U.S. dollar in the company’s European downstream operations.

Interest and debt expense was \$474 million in 2003, compared with \$565 million in 2002 and \$833 million in 2001. The declines between periods reflected lower average interest rates on commercial paper and other variable rate debt and lower average debt levels.

OPERATING, SELLING & ADMINISTRATIVE EXPENSES
Billions of dollars



The 8 percent increase in 2003 resulted primarily from higher costs for transportation, shipping, pension plans and other employee benefits.

Income tax expense corresponded to effective tax rates of 43 percent in 2003 and 45 percent in 2002 and 2001, after taking into account the effect of special items. See also Note 16 on pages 64 and 65, "Taxes," in the Notes to the Consolidated Financial Statements.

SELECTED OPERATING DATA

	2003	2002	2001
U.S. Exploration and Production			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)	562	602	614
Net Natural Gas Production (MMCFPD) ¹	2,228	2,405	2,706
Net Production (MBOEPD)	933	1,003	1,065
Natural Gas Sales (MMCFPD) ²	3,871	5,463	7,830
Natural Gas Liquids Sales (MBPD) ²	194	241	185
Revenues from Net Production			
Liquids (\$/Bbl)	\$26.66	\$ 21.34	\$ 21.33
Natural Gas (\$/MCF)	\$ 5.01	\$ 2.89	\$ 4.38
International Exploration and Production²			
Net Crude and Natural Gas			
Liquids Production (MBPD)	1,246	1,295	1,345
Net Natural Gas Production (MMCFPD) ¹	2,064	1,971	1,711
Net Production (MBOEPD)	1,590	1,623	1,630
Natural Gas Sales (MMCFPD)	1,951	3,131	2,675
Natural Gas Liquids Sales (MBPD)	107	131	115
Revenues from Liftings			
Liquids (\$/Bbl)	\$26.79	\$ 23.06	\$ 22.17
Natural Gas (\$/MCF)	\$ 2.64	\$ 2.14	\$ 2.36
Other Produced Volumes (MBPD) ³	114	97	105
U.S. Refining, Marketing and Transportation^{2,4}			
Gasoline Sales (MBPD)	669	680	709
Other Refined Products Sales (MBPD)	845	920	974
Refinery Input (MBPD)	951	979	983
Average Refined Products			
Sales Price (\$/Bbl)	\$39.93	\$ 32.63	\$ 36.26
International Refining, Marketing and Transportation²			
Gasoline Sales (MBPD)	543	519	533
Other Refined Products Sales (MBPD)	1,681	1,656	1,921
Refinery Input (MBPD)	1,040	1,100	1,136
Average Refined Products			
Sales Price (\$/Bbl)	\$46.64	\$ 37.18	\$ 48.90

¹ Includes natural gas consumed on lease:
 United States 65 64 64
 International 262 256 262

² Includes equity in affiliates, except as explained in footnote 4.

³ Other produced volumes includes:
 Athabasca Oil Sands – net 15 – –
 Boscan Operating Service Agreement 99 97 105

⁴ Excludes Equilon and Motiva.

MBPD = Thousands of barrels per day; MMCFPD = Millions of cubic feet per day;
 MBOEPD = Thousands of barrels of oil equivalents per day; Bbl = Barrel;
 MCF = Thousands of cubic feet.
 Oil-equivalent gas (OEG) conversion ratio is 6,000 cubic feet of gas = 1 barrel of oil.

INFORMATION RELATED TO INVESTMENT IN DYNEGY INC.

ChevronTexaco owns an approximate 26 percent equity interest in the common stock of Dynegy – an energy merchant engaged in power generation, natural gas liquids processing and marketing, and regulated energy delivery. The company also holds investments in Dynegy notes and preferred stock.

Investment in Dynegy Common Stock At December 31, 2003, the carrying value of the company's investment in Dynegy common stock was approximately \$150 million. This amount was about \$425 million below the company's proportionate interest in Dynegy's underlying net assets. This difference resulted from write-downs of the investment in 2002 for declines in the market value of the common shares below the company's carrying value that were deemed to be other than temporary. The approximate \$425 million difference has been assigned to the extent practicable to specific Dynegy assets and liabilities, based upon the company's analysis of the various factors giving rise to the decline in value of the Dynegy shares. The company's equity share of Dynegy's reported earnings is adjusted quarterly to reflect the difference between these allocated values and Dynegy's historical book values. The market value of the company's investment in Dynegy's common stock at December 31, 2003, was \$415 million.

Investments in Dynegy Notes and Preferred Stock At the beginning of 2003, the company held \$1.5 billion aggregate principal amount of Dynegy Series B Preferred Stock, which was due for redemption at par value in November 2003. In August, the company exchanged its preferred stock for \$225 million in cash, \$225 million face value of Dynegy Junior Unsecured Subordinated Notes due 2016 and \$400 million face value of Dynegy Series C Convertible Preferred Stock with a stated maturity of 2033.

The company recorded the Junior Notes and Series C Preferred Stock on the date of exchange at their fair values of \$170 million and \$270 million, respectively, for a total of \$440 million. Together with the \$225 million cash, the total amount recorded on the date of exchange was \$665 million. A gain of \$365 million was included in net income at that date for the difference between the \$665 million fair value received and the net balance sheet amount of \$300 million associated with the Series B shares.

At December 31, 2003, the estimated fair values of the Junior Notes and Series C shares totaled \$530 million. The \$90 million increase from the \$440 million recorded in August was recorded to "Investments and Advances," with an offsetting amount in "Other Comprehensive Income." Future temporary changes in the estimated fair values of the new securities likewise will be reported in "Other Comprehensive Income." However, if any future decline in fair value is deemed to be other than temporary, a charge against income in the period would be recorded. Interest that accrues on the notes and dividends payable on the preferred stock is recognized in income each period.

In addition to the \$365 million gain recorded in income in the third quarter 2003, the company recorded \$170 million directly to "Retained Earnings." The latter amount represented the company's approximate 26 percent equity share of a gain recorded by Dynegy in connection with the Series B exchange transaction. Under the accounting rules applicable to preferred

stock redemptions, ChevronTexaco increased its earnings per share in the third quarter 2003 by \$0.16 for the effect of the \$170 million recorded directly to "Retained Earnings."

In February 2004, Dynegy announced agreement to sell its Illinois Power subsidiary to Ameren Corporation. The sale is conditioned upon, among other things, the receipt of approvals from governmental and regulatory agencies. Pending these approvals, the acquisition is expected to close in the fourth quarter of 2004. The sale of Illinois Power triggers a mandatory prepayment provision in the Dynegy Junior Notes held by the company. Under the terms of that provision, 75 percent of the net proceeds, not including any amounts used for the payment of any debt associated with Illinois Power, are to be used to retire at par, plus accrued interest, the \$225 million face value notes.

LIQUIDITY AND CAPITAL RESOURCES

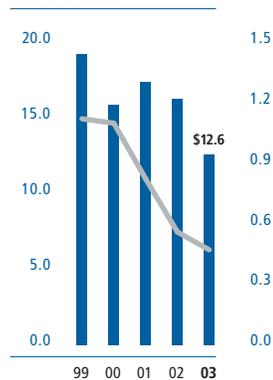
Cash, cash equivalents and marketable securities totaled \$5.3 billion and \$3.8 billion at December 31, 2003 and 2002, respectively. Cash provided by operating activities in 2003 was \$12.3 billion, compared with \$9.9 billion in 2002 and \$11.5 billion in 2001. The 2003 increase in cash provided by operating activities mainly

CASH PROVIDED BY OPERATING ACTIVITIES
Billions of dollars



Higher earnings helped boost the company's operating cash flow by 24 percent.

TOTAL INTEREST EXPENSE & TOTAL DEBT AT YEAR-END
Billions of dollars



■ Total Interest Expense (right scale)
■ Total Debt (left scale)
Interest expense fell 16 percent on significantly lower debt levels.

reflected higher earnings in the U.S. upstream and worldwide downstream businesses. Cash provided by asset sales was \$1.1 billion in 2003, \$2.3 billion in 2002 and about \$300 million in 2001. In 2002, the company received proceeds of \$2.2 billion, including dividends due, from the FTC-mandated sale of the company's investments in Equilon and Motiva. Cash provided by operating activities during 2003 generated sufficient funds for the company's capital and exploratory expenditure program and the payment of dividends to stockholders as well as contributing significantly to a reduction of \$3.7 billion in debt levels, \$1.4 billion funding of the company's pension plans and the increase in cash and cash equivalents and marketable securities.

Dividends Payments of approximately \$3 billion in 2003 and 2002 and \$2.9 billion in 2001 were made for dividends or distributions for common stock, preferred stock and minority interests.

Debt, capital lease and minority interest obligations ChevronTexaco's total debt and capital lease obligations totaled \$12.6 billion at December 31, 2003, down from \$16.3 billion at year-end 2002. The company also had minority interest obligations of \$268 million, down from \$303 million at December 31, 2002.

The company's debt and capital lease obligations due within one year, consisting primarily of commercial paper and the current portion of long-term debt, totaled \$6 billion at December 31, 2003, down from \$9.5 billion at December 31, 2002. Of these amounts, \$4.3 billion and \$4.1 billion, respectively, were reclassified to long-term at the end of each period. Settlement of the obligations at year-end 2003 was not expected to require the use of working capital in 2004, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis. The company's practice has been to continually refinance its commercial paper, maintaining levels it believes appropriate.

At year-end 2003, ChevronTexaco had \$4.3 billion in committed credit facilities with various major banks, which permit the refinancing of short-term obligations on a long-term basis. These facilities support commercial paper borrowings and also can be used for other general credit requirements. No borrowings were outstanding under these facilities during the year or at year-end 2003. In addition, the company had three existing effective "shelf" registrations on file with the Securities and Exchange Commission (SEC) that together would permit additional registered debt offerings up to an aggregate of \$3.8 billion of debt securities.

In 2003, the company issued \$1 billion of new long-term debt and other financing obligations, including \$750 million of 3.375 percent ChevronTexaco Capital notes due in February 2008, \$265 million of new Philippine debt and \$19 million of individually smaller issues. Proceeds from the ChevronTexaco Capital Company note issue were used to retire commercial paper. Repayments of long-term debt included \$665 million of Texaco Capital Inc. bonds, \$143 million of Philippine debt, \$110 million of ChevronTexaco Corporation 8.11 percent notes, \$128 million of Nigerian debt and \$91 million of individually smaller issues. Additionally, a \$210 million payment was made to the Republic of Kazakhstan relating to the company's 1993 acquisition of its interest in the TCO joint venture. Also included in the company's long-term debt levels was a noncash reduction of \$50 million of ESOP debt.

ChevronTexaco's senior debt is rated AA by Standard and Poor's Corporation and Aa2 by Moody's Investor Service, except for senior debt of Texaco Capital Inc., which is rated Aa3. ChevronTexaco's U.S. commercial paper is rated A-1+ by Standard and Poor's and Prime 1 by Moody's, and the company's Canadian commercial paper is rated R-1 (middle) by Dominion Bond Rating Service. All of these ratings denote high-quality, investment-grade securities.

The company's future debt level is dependent primarily on results of operations, the capital-spending program and cash that may be generated from asset dispositions. The company believes it has substantial borrowing capacity to meet unanticipated cash requirements and, for periods of low prices for crude oil and natural gas and narrow margins for refined products and commodity chemicals, the company believes that it has the flexibility to increase borrowings and/or modify capital-spending plans to continue paying the common stock dividend and maintain the company's high-quality debt ratings.

Capital and exploratory expenditures for 2003 totaled \$7.4 billion, including the company's equity share of affiliates' expenditures. Capital and exploratory expenditures were \$9.3 billion in 2002 and \$12 billion in 2001. ChevronTexaco's equity share of affiliates' expenditures were \$1.1 billion, \$1.4 billion and \$1.7 billion in 2003, 2002 and 2001, respectively, and did not require cash outlays by the company. Expenditures of \$5.7 billion in

EXPLORATION & PRODUCTION – CAPITAL & EXPLORATORY EXPENDITURES*

Billions of dollars



■ United States
■ International

International projects accounted for 71 percent of worldwide exploration and production expenditures in 2003.

*Includes equity in affiliates

2003 for exploration and production activities represented 77 percent of total outlays for the year, compared with 68 percent in 2002 and 59 percent in 2001. International exploration and production spending of \$4.0 billion was 71 percent of worldwide exploration and production expenditures in 2003, compared with 70 percent in 2002 and 66 percent in 2001, reflecting the company's continuing focus on international exploration and production activities.

Expenditures in 2003 were \$1.9 billion lower than the prior year, primarily due to amounts spent in 2002 for large lease acquisitions in the North Sea and the Gulf of Mexico, the Athabasca Oil Sands Project in western Canada, and additional common stock investments in

Dynegy. The largest expenditures in 2003 included upstream projects in Eurasia, West Africa and the Gulf of Mexico. Expenditures in 2002 included lower additional investments in equity

affiliates than in 2001 due to the absence of the company's share of expenditures for its Equilon and Motiva investments, which were sold as a condition of the merger. The 2001 expenditures included additional investments in TCO and Dynegy, including the purchase of \$1.5 billion of Dynegy preferred stock.

Including the share of spending by affiliates, the company estimates 2004 capital and exploratory expenditures at \$8.5 billion, which is about 15 percent higher than spending in 2003. About \$6.4 billion, or 75 percent of the total, is targeted for exploration and production activities, with \$4.5 billion of that outside the United States. The upstream spending is targeted for the most promising exploratory prospects in Nigeria, Angola and deepwater Gulf of Mexico and major development projects in Kazakhstan, Venezuela and Africa. Included in the upstream expenditures is about \$400 million to commercialize the company's international natural gas resource base, including the construction of additional liquefied natural gas (LNG) facilities to help meet future demand for natural gas. Additional LNG expenditures of about \$100 million are included in other segments of the 2004 capital program.

Worldwide downstream spending is estimated to be \$1.4 billion, with about \$1 billion of the amount on refining and marketing and \$400 million on supply and transportation projects. Investments in chemicals are budgeted at \$200 million. Estimates for power and related businesses are \$150 million. The remaining \$300 million is primarily for emerging technologies and information technology infrastructure.

Capital and Exploratory Expenditures

Millions of dollars	2003			2002			2001		
	U.S.	Int'l.	Total	U.S.	Int'l.	Total	U.S.	Int'l.	Total
Exploration and Production	\$ 1,641	\$ 4,034	\$ 5,675	\$ 1,888	\$ 4,395	\$ 6,283	\$ 2,420	\$ 4,709	\$ 7,129
Refining, Marketing and Transportation	403	697	1,100	750	882	1,632	873	1,271	2,144
Chemicals	173	24	197	272	37	309	145	34	179
All Other	371	20	391	855*	176*	1,031	2,570	6	2,576
Total	\$ 2,588	\$ 4,775	\$ 7,363	\$ 3,765	\$ 5,490	\$ 9,255	\$ 6,008	\$ 6,020	\$ 12,028
Total, Excluding Equity in Affiliates	\$ 2,306	\$ 3,920	\$ 6,226	\$ 3,312	\$ 4,590	\$ 7,902	\$ 4,934	\$ 5,382	\$ 10,316

*2002 conformed to the 2003 presentation.

Pension Obligations In 2003, contributions to the U.S. plans totaled \$1.2 billion. In early 2004, the company contributed \$535 million to the U.S. pension plans. Additionally, the company anticipates contributing about \$50 million to the U.S. plans during the remainder of the year. In years subsequent to 2004, the company expects contributions to the U.S. pension plans of about \$250 million per year, approximately equal to the cost of benefits earned in each year. In 2003, contributions to the international pension plans were \$214 million and contributions of \$200 million are anticipated in 2004. The actual contribution amounts are dependent upon investment returns, changes in pension obligations, regulatory environments and other economic factors. Additional funding may ultimately be required if investment returns are insufficient to offset increases in plan obligations. Refer also to the discussion of pension accounting in "Critical Accounting Estimates and Assumptions" beginning on page 42.

FINANCIAL RATIOS

Current Ratio – current assets divided by current liabilities. Generally, two items adversely affected ChevronTexaco's current ratio, but in the company's opinion do not affect its liquidity.

TOTAL DEBT TO TOTAL DEBT-PLUS-EQUITY RATIO

Billions of dollars/Percent



ChevronTexaco's ratio of total debt to total debt plus equity fell to 25.8 percent at year-end 2003 as the company's debt level declined by \$3.7 billion.

before-tax income, lower average debt balances and lower market interest rates.

Debt Ratio – total debt divided by total debt plus equity. This ratio was approximately 26 percent at December 31, 2003, compared with 34 percent a year earlier.

Financial Ratios

	At December 31		
	2003	2002	2001
Current Ratio	1.2	0.9	0.9
Interest Coverage Ratio	24.3	7.6	9.6
Total Debt/Total Debt Plus Equity	25.8%	34.0%	33.9%

GUARANTEES, OFF-BALANCE-SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS, AND OTHER CONTINGENCIES

Direct or Indirect Guarantees*

Millions of dollars	Commitment Expiration by Period				
	Total	2004	2005–2007	After 2008	
Guarantees of Non-Consolidated Affiliates or Joint Venture Obligations	\$ 917	\$ 703	\$ 93	\$ 6	\$ 115
Guarantees of Obligations of Third Parties	256	194	36	–	26
Guarantees of Equilon Debt and Leases	238	41	60	18	119

*The amounts exclude indemnifications of contingencies associated with the sale of the company's interest in Equilon and Motiva in 2002, as discussed in the "Indemnifications" section on page 38.

At December 31, 2003, the company and its subsidiaries provided guarantees, either directly or indirectly, of \$917 million in guarantees for notes and other contractual obligations of affiliated companies and \$256 million for third parties as described, by major category, below. There are no amounts being carried as liabilities for the company's obligations under these guarantees. Of the \$917 million in guarantees provided to affiliates, \$716 million relate to borrowings for capital projects or general corporate purposes. These guarantees were undertaken to achieve lower interest rates and generally cover the construction period of the capital projects. Approximately 75 percent of the amounts guaranteed will expire in 2004, with the remaining guarantees expiring by the end of 2015. Under the terms of the guarantees, the company would be required to fulfill the guarantee should an affiliate be in default of its loan terms, generally for the full amounts disclosed. There are no recourse provisions, and no assets are held as collateral for these guarantees.

The company provides guarantees of \$201 million relating to obligations in connection with pricing of power purchase agreements for certain of its cogeneration affiliates. Under the terms of these guarantees, the company may be required to make payments under certain conditions if the affiliate does not perform under the agreements. There are no recourse provisions to third parties, and no assets are held as collateral for these pricing guarantees.

Guarantees of \$256 million have been provided to third parties, including guarantees of approximately \$110 million of construction loans to host governments in the company's international upstream operations. The remaining guarantees of \$146 million were provided principally as conditions of sale of the company's interest in certain operations, to provide a source of liquidity to the guaranteed parties and in connection with company marketing programs. No amounts of the company's obligations under these guarantees are recorded as liabilities. About 75 percent of the total amounts guaranteed will expire in 2004, with the remainder expiring after 2004. The company would be required to perform under the terms of the guarantees should an entity be in default of its loan or contract terms, generally for the full amounts disclosed. Approximately \$100 million of the guarantees have recourse provisions, which enable the company to recover any payments made under the terms of the guarantees from securities held over the guaranteed parties' assets.

At December 31, 2003, ChevronTexaco had outstanding guarantees for approximately \$238 million of Equilon debt and leases. Following the February 2002 disposition of its interest in Equilon, the company received an indemnification from Shell

Oil Company (Shell) for any claims arising from the guarantees. Accordingly, the company has not recorded a liability for these guarantees. Approximately 50 percent of the amounts guaranteed will expire within the 2004–2008 period, with the guarantees of the remaining amounts expiring by 2019.

Indemnifications The company also provided certain indemnities of contingent liabilities of Equilon and Motiva to Shell and Saudi Refining Inc. in connection with the February 2002 sale of the company's interests in those investments. The indemnities cover certain contingent liabilities, including those associated with the Unocal patent litigation. The company would be required to perform should the indemnified liabilities become actual losses and could be required to make maximum future payments of \$300 million. The company has paid approximately \$28 million under these contingencies and has disputed approximately \$34 million in claims submitted by Shell under these indemnities. Shell has requested arbitration of this dispute, which is expected to occur in mid-2004. There are no recourse provisions enabling recovery of any amounts from third parties nor are any assets held as collateral. Within five years of the February 2002 sale, at the buyer's option, the company also may be required to purchase certain assets from Shell for their respective net book values, as determined at the time of the company's purchase. Under these terms, the company purchased two lubricant facilities in late 2003 for immaterial amounts.

The company has also provided indemnities relating to contingent environmental liabilities related to assets originally contributed by Texaco to the Equilon and Motiva joint ventures and environmental conditions that existed prior to the formation of Equilon and Motiva or that occurred during the periods of ChevronTexaco's ownership interests in the joint ventures. In general, the environmental conditions or events that are subject to these indemnities must have arisen prior to December 2001. Claims relating to Equilon must be asserted no later than February 2009, and claims relating to Motiva must be asserted no later than February 2012. Under the terms of the indemnities, there is no maximum limit on the amount of potential future payments. The company has not recorded any liabilities for possible claims under these indemnities. The company holds no assets as collateral and has made no payments under the indemnities.

The amounts payable for the indemnities described above are to be net of amounts recovered from insurance carriers and others and net of liabilities recorded by Equilon or Motiva prior to September 30, 2001, for any specific incident.

Securitization In other off-balance-sheet arrangements, the company securitizes certain retail and trade accounts receivable in its downstream business through the use of qualifying special purpose entities (SPEs). At December 31, 2003, approximately \$1 billion, representing about 11 percent of ChevronTexaco's total current accounts receivable balance, were securitized. ChevronTexaco's total estimated financial exposure under these arrangements at December 31, 2003, was approximately \$75 million. These arrangements have the effect of accelerating ChevronTexaco's collection of the securitized amounts. In the event the SPEs experienced major defaults in the collection of receivables, ChevronTexaco believes that it would have no loss exposure connected with third-party investments in these securitization arrangements.

Long-Term Unconditional Purchase Obligations and Commitments, Throughput Agreements, and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities relating to long-term unconditional purchase obligations and commitments, throughput agreements, and take-or-pay agreements, some of which relate to suppliers' financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate amounts of required payments under these various commitments are: 2004 – \$1.2 billion; 2005 – \$1.1 billion; 2006 – \$1 billion; 2007 – \$1 billion; 2008 – \$1 billion; 2009 and after – \$1.9 billion. Total payments under the agreements were approximately \$1.4 billion in 2003, \$1.2 billion in 2002 and \$1.5 billion in 2001. The most significant take-or-pay agreement calls for the company to purchase approximately 55,000 barrels per day of refined products from an equity affiliate refiner in Thailand. This purchase agreement is in conjunction with the financing of a refinery owned by the affiliate and expires in 2009. The future estimated commitments under this contract are: 2004 – \$700 million; 2005 – \$800 million; 2006 – \$800 million; 2007 – \$800 million; 2008 – \$800 million; 2009 – \$800 million.

Minority Interests The company has commitments related to preferred shares of subsidiary companies that are accounted for as minority interest. Texaco Capital LLC, a wholly owned finance subsidiary, has issued \$65 million of Deferred Preferred Shares Series C. Dividends of approximately \$60 million on Series C, at a rate of 7.17 percent compounded annually, will be paid at the redemption date in February 2005 unless earlier redemption occurs. Early redemption may result upon the occurrence of certain specific events. MVP Production Inc., a subsidiary, redeemed variable rate cumulative preferred shares of \$75 million owned by one minority holder during 2003.

The following table summarizes the company's significant contractual obligations:

Contractual Obligations

	Payments Due by Period				
	Total	2004	2005– 2007	2008	After 2008
Millions of dollars					
On Balance Sheet:					
Short-Term Debt ¹	\$ 1,703	\$ 1,703	\$ –	\$ –	\$ –
Long-Term Debt ^{1,2}	10,651	–	5,012	1,044	4,595
Noncancelable Capital					
Lease Obligations	243	–	64	179	–
Redemption of Subsidiary's					
Preferred Shares	160	–	125	–	35
Off Balance Sheet:					
Noncancelable Operating					
Lease Obligations	2,034	299	754	181	800
Unconditional Purchase					
Obligations	700	300	300	100	–
Through-Put and					
Take-or-Pay Agreements	6,500	900	2,800	900	1,900

¹ \$4,285 of short-term debt that the company expects to refinance is included in long-term debt. The repayment schedule reflects the expiration of the company's committed credit facilities, although the facilities may be renewed upon expiration.

² Includes guarantees of \$385 of LESOP debt, \$25 due in 2004 and \$360 due after 2007.

The company also has other obligations connected with asset retirements and pension plans that are not contractually fixed as to timing and amount.

FINANCIAL AND DERIVATIVE INSTRUMENTS

Commodity Derivative Instruments ChevronTexaco is exposed to market risks related to the volatility of crude oil, refined products, natural gas and refinery feedstock prices. The company uses derivative commodity instruments to manage its exposure to price volatility on a small portion of its activity, including: firm commitments and anticipated transactions for the purchase or sale of crude oil; feedstock purchases for company refineries; crude oil and refined products inventories; and fixed-price contracts to sell natural gas and natural gas liquids.

The company also uses derivative commodity instruments for trading purposes, the results of which were not material to the company's financial position, net income or cash flows in 2003.

The company's positions are monitored and managed on a daily basis by an internal risk control group to ensure compliance with the company's risk management policy that has been approved by the Audit Committee of the company's Board of Directors.

The derivative instruments used in the company's risk management and trading activities consist mainly of futures contracts traded on the New York Mercantile Exchange and the International Petroleum Exchange; crude oil and natural gas swap contracts; options and other derivative products entered into principally with major financial institutions; and other oil and gas companies. Virtually all derivatives beyond those designated as normal purchase and normal sale contracts are recorded at fair value on the Consolidated Balance Sheet with resulting gains and losses reflected in income. Fair values are derived principally from market quotes and other independent third-party quotes.

The aggregate effect of a 10 percent change in prices for derivative contracts for natural gas, crude oil and petroleum products would be approximately \$20 million. The hypothetical effect on these contracts was estimated by calculating the cash value of the contracts as the difference between the hypothetical and contract delivery prices, multiplied by the contract amounts.

Foreign Currency The company enters into forward exchange contracts, generally with terms of 180 days or less, to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments, forecasted to occur within 180 days. The forward exchange contracts are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

The aggregate effect on foreign exchange contracts of a hypothetical 10 percent change to year-end exchange rates would be approximately \$35 million.

Interest Rates The company enters into interest rate swaps as part of its overall strategy to manage the interest rate risk on its debt. Under the terms of the swaps, net cash settlements are based on the difference between fixed-rate and floating-rate interest amounts calculated by reference to agreed notional principal amounts. Interest rate swaps related to a portion of the company's fixed-rate debt are accounted for as fair value hedges, whereas interest rate swaps relating to a portion of the company's floating-rate debt are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. During 2003, no new swaps were initiated. At year-end 2003, the weighted average maturity of "receive fixed" interest rate swaps was approximately five years. There were no "receive floating" swaps outstanding at year end.

A hypothetical 10 percent increase in interest rates upon the interest rate swaps would cause the fair value of the "receive fixed" swaps to decline and the "receive floating" swaps to increase. The aggregate effect of these changes would be approximately \$10 million.

TRANSACTIONS WITH RELATED PARTIES

ChevronTexaco enters into a number of business arrangements with related parties, principally its equity affiliates. These arrangements include long-term supply or offtake agreements. In January 2003, ChevronTexaco and Dynegy agreed to terminate the natural gas sale and purchase agreements. Internationally, there are long-term purchase agreements in place with the company's refining affiliate in Thailand. Refer to page 38 for further discussion. Management believes the foregoing agreements and others have been negotiated on terms consistent with those that would have been negotiated with an unrelated party.

LITIGATION AND OTHER CONTINGENCIES

Unocal Patent Litigation Chevron, Texaco and four other oil companies (refiners) filed suit in 1995, contesting the validity of a patent ('393' patent) granted to Unocal Corporation (Unocal) for certain reformulated gasoline blends. ChevronTexaco sells reformulated gasolines in California in certain months of the year. In March 2000, the U.S. Court of Appeals for the Federal Circuit upheld a September 1998 District Court decision that Unocal's patent was valid and enforceable and assessed damages of 5.75 cents per gallon for gasoline produced during the summer of 1996 that infringed on the claims of the patent. In February 2001, the U.S. Supreme Court concluded it would not review the lower court's ruling, and the case was sent back to the District Court for an accounting of all infringing gasoline produced after August 1, 1996. The District Court ruled that the

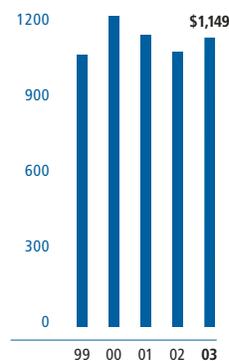
per-gallon damages awarded by the jury are limited to infringement that occurs in California only. Additionally, the U.S. Patent and Trademark Office (USPTO) granted three petitions by the refiners to re-examine the validity of Unocal's '393' patent and has twice rejected all of the claims in the '393' patent. Those rejections have been appealed by Unocal to the USPTO Board of Appeals. The District Court judge requested further briefing and advised that she would not enter a final judgment in this case until the USPTO had completed its re-examination of the '393' patent. During 2002 and 2003, the USPTO granted two petitions for reexamination of another Unocal patent, the '126' patent. The USPTO has rejected the validity of the claims of the '126' patent, which could affect a larger share of U.S. gasoline production. Separately, in March 2003, the Federal Trade Commission (FTC) filed a complaint against Unocal alleging that its conduct during the pendency of the patents was in violation of antitrust law. In November 2003, the Administrative Law Judge dismissed the complaint brought by the FTC. The FTC has appealed the decision.

Unocal has obtained additional patents that could affect a larger share of U.S. gasoline production. ChevronTexaco believes these additional patents are invalid, unenforceable and/or not infringed. The company's financial exposure in the event of unfavorable conclusions to the patent litigation and regulatory reviews may include royalties, plus interest, for production of gasoline that is proved to have infringed the patents. The competitive and financial effects on the company's refining and marketing operations, although presently indeterminable, could be material. ChevronTexaco has been accruing in the normal course of business any future estimated liability for potential infringement of the '393' patent covered by the 1998 trial court's ruling. In 2000, prior to the merger, Chevron and Texaco made payments to Unocal totaling approximately \$30 million for the original court ruling, including interest and fees.

MTBE Another issue involving the company is the petroleum industry's use of methyl tertiary butyl ether (MTBE) as a gasoline additive and its potential environmental impact through seepage into groundwater. Along with other oil companies, the company is a party to more than 60 lawsuits and claims related to the use of the chemical MTBE in certain oxygenated gasolines. These actions may require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future. The company's ultimate exposure related to these lawsuits and claims is not currently determinable, but could be material to net income in any one period. ChevronTexaco has reduced the use of MTBE in gasoline it manufactures in the United States, including the complete phase-out of MTBE in California before the end of 2003.

Environmental The company is subject to loss contingencies pursuant to environmental laws and regulations that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemicals or petroleum substances, including MTBE, by the company or other parties. Such contingencies may exist for various sites, including, but not limited to Superfund sites and refineries, oil fields, service stations, terminals, and land development areas, whether operating, closed or sold. The following table displays the annual changes to the company's before-tax environmental remediation reserves, including those for Superfund sites. In 2003, the company recorded additional provisions for estimated remediation costs, primarily at refined products marketing sites and various closed or divested facilities in the United States.

YEAR-END ENVIRONMENTAL REMEDIATION RESERVES
Millions of dollars



Reserves for environmental remediation increased 5 percent during 2003. Expenditures during the year were approximately \$200 million.

Millions of dollars	2003	2002	2001
Balance at January 1	\$ 1,090	\$ 1,160	\$ 1,234
Additions	296	229	216
Expenditures	(237)	(299)	(290)
Balance at December 31	\$ 1,149	\$ 1,090	\$ 1,160

As of December 31, 2003, ChevronTexaco had been identified by the Environmental Protection Agency (EPA) or other regulatory agencies under the provisions of the U.S. Superfund law as a potentially responsible party or otherwise involved in the remediation of 218 sites. The company's remediation reserve for these sites at year-end 2003 was \$113 million. The Superfund law provides for joint and several liability for all responsible parties. Any future actions by the EPA and other regulatory agencies to require ChevronTexaco to assume other potentially responsible parties' costs at designated hazardous waste sites are not expected to have a material effect on the company's consolidated financial position or liquidity.

It is likely that the company will continue to incur additional liabilities, beyond those recorded, for environmental remediation relating to past operations. These future costs are indeterminable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties. Although the amount of future costs may be material to the company's results of operations in the period in which they are recognized, the company does not expect these costs will have a material adverse effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had, or will have, any significant

impact on the company's competitive position relative to other petroleum or chemicals companies.

Prior to January 1, 2003, additional reserves for dismantlement, abandonment and restoration of its worldwide oil, gas and coal properties at the end of their productive lives, which included costs related to environmental issues, were recognized on a unit-of-production basis. Effective January 1, 2003, the company implemented Financial Accounting Standards Board Statement No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). Under FAS 143, the fair value of a liability for an asset retirement obligation is recorded when there is a legal obligation associated with the retirement of long-lived assets and the liability can be reasonably estimated. The liability balance for asset retirement obligations at year-end 2003 was \$2.9 billion. Refer also to Note 25 on page 74 related to FAS 143.

For the company's other ongoing operating assets, such as refineries and chemicals facilities, no provisions are made for exit or cleanup costs that may be required when such assets reach the end of their useful lives unless a decision to sell or otherwise abandon the facility has been made, as the indeterminate settlement dates for the asset retirements prevent estimation of the fair value of the asset retirement obligation.

Refer to "Environmental Matters" below for additional information related to environmental matters.

Income Taxes The company estimates its income tax expense and liabilities annually. These liabilities generally are not finalized with the individual taxing authorities until several years after the end of the annual period for which income taxes have been estimated. The U.S. federal income tax liabilities have been settled through 1996 for ChevronTexaco (formerly Chevron), 1993 for ChevronTexaco Global Energy Inc. (formerly Caltex), and 1991 for Texaco. California franchise tax liabilities have been settled through 1991 for Chevron and through 1987 for Texaco. Settlement of open tax years, as well as tax issues in other countries where the company conducts its businesses, is not expected to have a material effect on the consolidated financial position or liquidity of the company, and in the opinion of management, adequate provision has been made for income and franchise taxes for all years under examination or subject to future examination.

Global Operations ChevronTexaco and its affiliates have operations in more than 180 countries. Areas in which the company and its affiliates have major operations include the United States, Canada, Australia, the United Kingdom, Norway, Denmark, France, Partitioned Neutral Zone between Kuwait and Saudi Arabia, Republic of Congo, Angola, Nigeria, Chad, Cameroon, Equatorial Guinea, Democratic Republic of Congo, South Africa, Indonesia, the Philippines, Singapore, China, Thailand, Venezuela, Argentina, Brazil, Colombia, Trinidad and Tobago, and South Korea. The company's Tengizchevroil affiliate operates in Kazakhstan. The company's Caspian Pipeline Consortium (CPC) affiliate operates in Russia and Kazakhstan. The company's Chevron Phillips Chemical Company LLC affiliate manufactures and markets a wide range of petrochemicals on a worldwide basis, with manufacturing facilities in the United States, Puerto Rico, Singapore, China, South Korea, Saudi Arabia, Qatar, Mexico and Belgium.

The company's operations, particularly exploration and production, can be affected by changing economic, regulatory and political environments in the various countries in which it operates, including the United States. As has occurred in the past, actions could be taken by host governments to increase public ownership of the company's partially or wholly owned

businesses and/or to impose additional taxes or royalties on the company's operations.

In certain locations, host governments have imposed restrictions, controls and taxes, and in others, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries. Internal unrest or strained relations between a host government and the company or other governments may affect the company's operations. Those developments have, at times, significantly affected the company's related operations and results and are carefully considered by management when evaluating the level of current and future activity in such countries.

Equity Redetermination For oil and gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated oil and gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for ChevronTexaco's interests in four producing zones at the Naval Petroleum Reserve at Elk Hills, California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range remains for a possible net settlement amount for the four zones. ChevronTexaco currently estimates its maximum possible net before-tax liability at approximately \$200 million. At the same time, a possible maximum net amount that could be owed to ChevronTexaco is estimated at about \$50 million. The timing of the settlement and the exact amount within this range of estimates is uncertain.

Suspended Wells The company also suspends the costs of exploratory wells pending a final determination of the commercial potential of the related oil and gas fields. The ultimate disposition of these well costs is dependent on the results of future drilling activity and/or development decisions. If the company decides not to continue development, the costs of these wells are expensed. At December 31, 2003, the company had \$658 million of suspended exploratory wells included in properties, plant and equipment, an increase of \$208 million from 2002 and a decrease of \$30 million from 2001. The increase in 2003 primarily reflects drilling activities in the United States and Nigeria.

Other Contingencies ChevronTexaco receives claims from and submits claims to customers, trading partners, U.S. federal, state and local regulatory bodies, host governments, contractors, insurers and suppliers. The amounts of these claims, individually and in the aggregate, may be significant and may take lengthy periods of time to resolve.

The company and its affiliates also continue to review and analyze their operations and may close, abandon, sell, exchange, acquire or restructure assets to achieve operational or strategic benefits and to improve competitiveness and profitability. These activities, individually or together, may result in gains or losses in future periods.

ENVIRONMENTAL MATTERS

Virtually all aspects of the businesses in which the company engages are subject to various federal, state and local environmental, health and safety laws and regulations. These regulatory requirements continue to increase in both number and complexity over time and govern not only the manner in which the company conducts its operations, but also the products it sells. Most of the costs of complying with laws and regulations pertaining to company operations and products are embedded in the normal costs of doing business.

Accidental leaks and spills requiring cleanup may occur in the ordinary course of business. In addition to the costs for environmental protection associated with its ongoing operations and products, the company may incur expenses for corrective actions at various owned and previously owned facilities and at third-party-owned waste-disposal sites used by the company. An obligation may arise when operations are closed or sold and at non-ChevronTexaco sites where company products have been handled or disposed of. Most of the expenditures to fulfill these obligations relate to facilities and sites where past operations followed practices and procedures that were considered acceptable at the time but now require investigative and/or remedial work to meet current standards. Using definitions and guidelines established by the American Petroleum Institute, ChevronTexaco estimated its worldwide environmental spending in 2003 at approximately \$1.1 billion for its consolidated companies. Included in these expenditures were \$305 million of environmental capital expenditures and \$820 million of costs associated with the control and abatement of hazardous substances and pollutants from ongoing operations.

For 2004, total worldwide environmental capital expenditures are estimated at \$430 million. These capital costs are in addition to the ongoing costs of complying with environmental regulations and the costs to remediate previously contaminated sites.

It is not possible to predict with certainty the amount of additional investments in new or existing facilities or amounts of incremental operating costs to be incurred in the future to: prevent, control, reduce or eliminate releases of hazardous materials into the environment; comply with existing and new environmental laws or regulations; or remediate and restore areas damaged by prior releases of hazardous materials. Although these costs may be significant to the results of operations in any single period, the company does not expect them to have a material effect on the company's liquidity or financial position.

CRITICAL ACCOUNTING ESTIMATES AND ASSUMPTIONS

Management makes many estimates and assumptions in the application of generally accepted accounting principles (GAAP) that may have a material impact on the company's consolidated financial statements and related disclosures and on the comparability of such information over different reporting periods. All such estimates and assumptions affect reported amounts of assets, liabilities, revenues and expenses as well as disclosures of contingent assets and liabilities. Estimates and assumptions are based on management's experience and other information available prior to the issuance of the financial statements. Materially different results can occur as circumstances change and additional information becomes known.

The discussion in this section of critical accounting estimates or assumptions is according to the disclosure guidelines of the Securities and Exchange Commission (SEC), wherein:

1. The nature of the estimates or assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters, or the susceptibility of such matters to change, and

2. The impact of the estimates and assumptions on the company's financial condition or operating performance is material.

Besides those meeting the critical criteria, the company makes many other accounting estimates and assumptions in preparing its financial statements and related disclosures. Although not associated with "highly uncertain matters," these estimates and assumptions are also subject to revision as circumstances warrant, and materially different results may sometimes occur.

For example, the recording of deferred tax assets requires an assessment under the accounting rules that the future realization of the associated tax benefits be "more likely than not." Another example is the estimation of oil and gas reserves under SEC rules that require "...geological and engineering data (that demonstrate with reasonable certainty (reserves) to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made." Refer to Table V, "Reserve Quantity Information," on page 81 for the changes in these estimates for the three years ending December 31, 2003, and to Table VII, "Changes in the Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves," on page 83 for estimates of proved-reserve values for each year-end 2001–2003, which were based on year-end prices at the time. Note 1 to the Consolidated Financial Statements includes a description of the "successful efforts" method of accounting for oil and gas exploration and production activities. The estimates of crude oil and natural gas reserves are important to the timing of expense recognition for costs incurred.

The discussion of the critical accounting policy for "Impairment of Property, Plant and Equipment and Investments in Affiliates" on pages 43 and 44 includes reference to conditions under which downward revisions of proved reserve quantities could result in impairments of oil and gas properties. This commentary should be read in conjunction with disclosures elsewhere in this discussion and in the Notes to the Consolidated Financial Statements related to estimates, uncertainties, contingencies and new accounting standards. Significant accounting policies are discussed in Note 1 to the Consolidated Financial Statements beginning on page 52. The development and selection of accounting estimates and assumptions, including those deemed critical, and the associated disclosures in this discussion have been discussed by management with the audit committee of the Board of Directors.

The areas of accounting and the associated critical estimates and assumptions made by the company are as follows:

Pension and Other Postretirement Benefit Plans The determination of pension plan expense and the requirements for funding of the company's major pension plans are based on a number of actuarial assumptions. Two critical assumptions are the rate of return on pension plan assets and the discount rate applied to pension plan obligations. For other postretirement employee benefit (OPEB) plans, which provide for certain health care and life insurance for qualifying retired employees and which are not funded, critical assumptions in determining OPEB expense are the discount rate applied to benefit obligations and the assumed health care cost-trend rates used in the calculation of benefit obligations.

Note 21 to the Consolidated Financial Statements, beginning on page 66, includes information for the three years ending December 31, 2003, on the components of pension and OPEB expense and the underlying discount rate assumptions as well as on the funded status for the company's pension plans at the end of 2003 and 2002.

To determine the estimate of long-term rate of return on pension assets, the company employs a rigorous process that incorporates actual historical asset-class returns and an assessment of expected future performance, and takes into consideration external actuarial advice and asset-class risk factors. Asset allocations are regularly updated using pension plan asset/liability studies, and the determination of the company's estimates of long-term rates of return are consistent with these studies. For example, at December 31, 2003 and 2002, the estimated long-term rate of return on U.S. pension plan assets, which account for about 70 percent of the company's pension plan assets, was 7.8 percent, as compared with 9 percent at the end of 2001. The year-end market-related value of U.S. pension-plan assets used in the determination of pension expense was based on the market values in the preceding three months as opposed to the maximum allowable period of five years under U.S. accounting rules. Management considers the three-month time period long enough to minimize the effects of distortions from day-to-day market volatility and still be contemporaneous to the end of the year.

The discount rate used in the determination of pension benefit obligations and pension expense is based on high-quality fixed income investment interest rates. At December 31, 2003, the company calculated the U.S. pension obligations using a 6.0 percent discount rate. The discount rates used at the end of 2002 and 2001 were 6.8 percent and 7.3 percent, respectively.

An increase in the expected return on pension plan assets or the discount rate would reduce pension plan expense, and vice versa. Total pension expense for 2003 was \$697 million. As an indication of interest-rate sensitivity to the determination of pension expense, a 1 percent increase in the expected return on assets of the company's primary U.S. pension plan, which accounted for about 61 percent of the companywide pension obligation, would have reduced total pension plan expense for 2003 by approximately \$30 million. A 1 percent increase in the discount rate for this same plan would have reduced total benefit plan expense by approximately \$120 million. The actual rates of return on plan assets and discount rates may vary significantly from estimates because of unanticipated changes in the world's financial markets.

Based on the expected changes in pension plan asset values and pension obligations in 2004, the company does not believe any significant funding of the pension plans will be mandatory during the year. For the U.S. plans, this determination was made in accordance with the minimum funding standard of the Employee Retirement Income Security Act (ERISA). However, the company made discretionary contributions of \$535 million to U.S. plans in early 2004. Later in 2004, additional discretionary payments of \$200 million and \$50 million for the international and U.S. plans, respectively, are anticipated.

Pension expense is included on the Consolidated Statement of Income in "Operating expenses" or "Selling, general and administrative expenses" and applies to all business segments. Depending upon the funding status of the different plans, either a long-term prepaid asset or a long-term liability is recorded for plans with overfunding or underfunding, respectively. Any unfunded accumulated benefit obligation in excess of recorded liabilities is recorded in "Other comprehensive income." See Note

21 to the Consolidated Financial Statements beginning on page 66 for the pension-related balance sheet effects at the end of 2003 and 2002.

For the company's OPEB plans, expense for 2003 was \$228 million and was also recorded as "Operating expenses" or "Selling, general and administrative expenses" in all business segments. The discount rate applied to the company's U.S. OPEB obligations at December 31, 2003 was 6.0 percent – the same discount rate used for U.S. pension obligations. The assumed health care cost-trend rates used to calculate OPEB obligations starting in 2003 was an 8.4 percent cost increase over the previous year gradually dropping over four years to a long-term ultimate rate-increase assumption of 4.5 percent for 2007 and thereafter. The health care cost-trend increase assumption and duration to reach that rate are company estimates, developed in consultation with external consultants, and are consistent with the company's actual experience.

As an indication of discount-rate sensitivity to the determination of OPEB expense in 2003, a 1 percent increase in the discount rate for the company's primary U.S. OPEB plan, which accounted for the significant majority of the companywide OPEB obligation, would have decreased OPEB expense by approximately \$10 million.

Impairment of Property, Plant and Equipment and Investments in Affiliates The company assesses its property, plant and equipment (PP&E) for possible impairment whenever events or changes in circumstances indicate that the carrying value of the assets may not be recoverable. Such indicators include changes in the company's business plans, changes in commodity prices and for oil and gas properties, significant downward revisions of estimated proved reserve quantities. If the carrying value of an asset exceeds the future undiscounted cash flows expected from the asset, an impairment charge is recorded for the excess of carrying value of the asset over its fair value.

Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation and technology improvements on operating expenses and the outlook for global or regional market supply and demand conditions for crude oil, natural gas, commodity chemicals and refined products. However, the impairment reviews and calculations are based on assumptions that are consistent with the company's business plans and long-term investment decisions.

The amount and income statement classification of major impairments of PP&E for the three years ending December 31, 2003, are included in the commentary on the business segments elsewhere in this discussion, as well as in Note 3 to the Consolidated Financial Statements on pages 54 and 55. An estimate as to the sensitivity to earnings for these periods if other assumptions had been used in the impairment reviews and impairment calculations is not practicable, given the broad range of the company's PP&E and the number of assumptions involved in the estimates. That is, favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused an additional unknown number of other assets to become impaired.

Investments in common stock of affiliates that are accounted for under the equity method as well as investments in other securities of these equity investees are reviewed for impairment when the fair value of the investment falls below the company's carrying value. When such a decline is deemed to be other than temporary, an impairment charge is recorded to the

income statement for the difference between the investment's carrying value and its estimated fair value at the time. In making the determination as to whether a decline is other than temporary, the company considers such factors as the duration and extent of the decline, the investee's financial performance and the company's ability and intention to retain its investment for a period that will be sufficient to allow for any anticipated recovery in the investment's market value. Differing assumptions could affect whether an investment is impaired in any period and the amount of the impairment and are not subject to sensitivity analysis.

From time to time, the company performs impairment reviews and determines that no write-down in the carrying value of an asset or asset group is required. For example, when significant downward revisions to crude oil and natural gas reserves are made for any single field or concession, an impairment review is performed to determine if the carrying value of the asset remains recoverable. Also, if the expectation of sale of a particular asset or asset group in any period has been deemed more likely than not, an impairment review is performed, and if the estimated net proceeds exceed the carrying value of the asset or asset group, no impairment charge is required. Such calculations are reviewed each period until the asset or asset group is disposed of. Assets that are not impaired on a held-and-used basis could possibly become impaired if a decision was made to sell such assets and the estimated proceeds were less than the associated carrying values.

Contingent Losses Management also makes judgments and estimates in recording liabilities for claims, litigation, tax matters and environmental remediation. Actual costs can frequently vary from estimates for a variety of reasons. For example, the costs from settlement of claims and litigation can vary from estimates based on differing interpretations of laws, opinions on culpability and assessments on the amount of damages. Similarly, liabilities for environmental remediation are subject to change because of changes in laws, regulations and their interpretation; the determination of additional information on the extent and nature of site contamination; and improvements in technology.

Under the accounting rules, a liability is recorded for these types of contingencies if management determines the loss to be both probable and estimable. The company generally records these losses as "Operating expenses" or "Selling, general and administrative expenses" on the Consolidated Statement of Income. Refer to the business segment discussions elsewhere in this discussion and in Note 3 to the Consolidated Financial Statements on pages 54 and 55 for the effect on earnings from losses associated with certain litigation and environmental remediation and tax matters for the three years ended December 31, 2003.

An estimate as to the sensitivity to earnings for these periods if other assumptions had been used in recording these liabilities is not practical because of the number of contingencies that must be assessed, the number of underlying assumptions and the wide range of reasonably possible outcomes, in terms of both the probability of loss and the estimates of such loss.

NEW ACCOUNTING STANDARDS

In January 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46). FIN 46 amended Accounting Research Bulletin (ARB) 51, "Consolidated Financial Statements," and established standards for determining circumstances under which a variable interest entity (VIE) should be consolidated by its primary beneficiary. FIN 46 also requires disclosures about VIEs that the company is not required to consolidate but in which it has a significant variable interest. In December 2003, the FASB issued FIN 46-R, which not only included amendments to FIN 46, but also required application of the interpretation to all affected entities no later than March 31, 2004 for calendar-year reporting companies. Prior to this requirement, however, companies must apply the interpretation to special-purpose entities by December 31, 2003. The adoption of FIN 46-R as it relates to special-purpose entities did not have a material impact on the company's results of operations, financial position or liquidity, and the company does not expect a material impact upon its full adoption of the interpretation as of March 31, 2004.

ACCOUNTING FOR MINERAL INTERESTS INVESTMENT

The SEC has questioned certain public companies in the oil and gas and mining industries as to the proper accounting for, and reporting of, acquired contractual mineral interests under FASB Statement No. 141, "Business Combinations" (FAS 141), and FASB Statement No. 142, "Goodwill and Intangible Assets" (FAS 142). These accounting standards became effective for the company on July 1, 2001, and January 1, 2002, respectively.

At issue is whether such mineral interest costs should be classified on the balance sheet as part of "Properties, plant and equipment" or as "Intangible assets." The company will continue to classify these costs as "Properties, plant and equipment" and apportion them to expense in future periods under the company's existing accounting policy until authoritative guidance is provided.

For ChevronTexaco, the net book values of this category of mineral interest investment at December 31, 2003 and 2002, were \$3.8 billion and \$4.1 billion, respectively. If reclassification of these balances becomes necessary, the company's statements of income and cash flows would not be affected. However, additional disclosures related to intangible assets would be required as prescribed under the associated accounting standards.

REPORT OF MANAGEMENT

To the Stockholders of ChevronTexaco Corporation

Management of ChevronTexaco is responsible for preparing the accompanying financial statements and for ensuring their integrity and objectivity. The statements were prepared in accordance with accounting principles generally accepted in the United States of America and fairly represent the transactions and financial position of the company. The financial statements include amounts that are based on management's best estimates and judgments.

The company's statements have been audited by PricewaterhouseCoopers LLP, independent auditors selected by the Audit Committee and approved by the stockholders. Management has made available to PricewaterhouseCoopers LLP all the company's financial records and related data, as well as the minutes of stockholders' and directors' meetings.

Management of the company has established and maintains a system of internal accounting controls that is designed to provide reasonable assurance that assets are safeguarded, transactions are properly recorded and executed in accordance with management's authorization, and the books and records accurately reflect the disposition of assets. The system of internal controls includes appropriate division of responsibility. The company maintains an internal audit department that conducts an extensive program of internal audits and independently assesses the effectiveness of the internal controls.

The Audit Committee is composed of directors who are not officers or employees of the company. It meets regularly with members of management, the internal auditors and the independent auditors to discuss the adequacy of the company's internal controls, its financial statements, and the nature, extent and results of the audit effort. Both the internal and the independent auditors have free and direct access to the Audit Committee without the presence of management.



DAVID J. O'REILLY
Chairman of the Board
and Chief Executive Officer



JOHN S. WATSON
Vice President, Finance
and Chief Financial Officer



STEPHEN J. CROWE
Vice President
and Comptroller

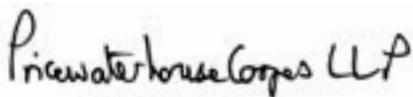
February 25, 2004

REPORT OF INDEPENDENT AUDITORS

To the Stockholders and the Board of Directors of ChevronTexaco Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, stockholders' equity and cash flows present fairly, in all material respects, the financial position of ChevronTexaco Corporation and its subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States. 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 of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 25 on page 74 to the financial statements, the Company changed its method of accounting for asset retirement obligations as of January 1, 2003.



San Francisco, California
February 25, 2004



Consolidated Statement of Income

Millions of dollars, except per-share amounts

	Year ended December 31		
	2003	2002	2001
REVENUES AND OTHER INCOME			
Sales and other operating revenues*	\$ 120,032	\$ 98,691	\$ 104,409
Income (loss) from equity affiliates	1,029	(25)	1,144
Gain from exchange of Dynegy preferred stock	365	–	–
Other income	335	247	692
TOTAL REVENUES AND OTHER INCOME	121,761	98,913	106,245
COSTS AND OTHER DEDUCTIONS			
Purchased crude oil and products	71,583	57,249	60,549
Operating expenses	8,553	7,848	7,650
Selling, general and administrative expenses	4,440	4,155	3,984
Exploration expenses	571	591	1,039
Depreciation, depletion and amortization	5,384	5,231	7,059
Write-down of investments in Dynegy Inc.	–	1,796	–
Merger-related expenses	–	576	1,563
Taxes other than on income*	17,906	16,689	15,156
Interest and debt expense	474	565	833
Minority interests	80	57	121
TOTAL COSTS AND OTHER DEDUCTIONS	108,991	94,757	97,954
INCOME BEFORE INCOME TAX EXPENSE	12,770	4,156	8,291
INCOME TAX EXPENSE	5,344	3,024	4,360
NET INCOME BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	\$ 7,426	\$ 1,132	\$ 3,931
Extraordinary loss, net of tax	–	–	(643)
Cumulative effect of changes in accounting principles	(196)	–	–
NET INCOME	\$ 7,230	\$ 1,132	\$ 3,288
PER-SHARE AMOUNTS			
BASIC:			
NET INCOME BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	\$ 7.15	\$ 1.07	\$ 3.71
Extraordinary item	\$ –	\$ –	\$ (0.61)
Cumulative effect of changes in accounting principles	\$ (0.18)	\$ –	\$ –
NET INCOME	\$ 6.97	\$ 1.07	\$ 3.10
DILUTED:			
NET INCOME BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	\$ 7.14	\$ 1.07	\$ 3.70
Extraordinary item	\$ –	\$ –	\$ (0.61)
Cumulative effect of changes in accounting principles	\$ (0.18)	\$ –	\$ –
NET INCOME	\$ 6.96	\$ 1.07	\$ 3.09
*Includes consumer excise taxes:	\$ 7,095	\$ 7,006	\$ 6,546

See accompanying Notes to the Consolidated Financial Statements.

» Consolidated Statement of Comprehensive Income

Millions of dollars

	Year ended December 31		
	2003	2002	2001
NET INCOME	\$ 7,230	\$ 1,132	\$ 3,288
Currency translation adjustment			
Unrealized net change arising during period	32	15	(11)
Unrealized holding gain on securities			
Net gain (loss) arising during period			
Before income taxes	445	(149)	3
Income taxes	–	52	–
Reclassification to net income of net realized (gain) loss			
Before income taxes	(365)	217	–
Income taxes	–	(76)	–
Total	80	44	3
Net derivatives gain on hedge transactions			
Before income taxes	115	52	3
Income taxes	(40)	(18)	–
Total	75	34	3
Minimum pension liability adjustment			
Before income taxes	12	(1,208)	14
Income taxes	(10)	423	(5)
Total	2	(785)	9
OTHER COMPREHENSIVE GAIN (LOSS), NET OF TAX	189	(692)	4
COMPREHENSIVE INCOME	\$ 7,419	\$ 440	\$ 3,292

See accompanying Notes to the Consolidated Financial Statements.

Millions of dollars, except per-share amounts

	At December 31	
	2003	2002
ASSETS		
Cash and cash equivalents	\$ 4,266	\$ 2,957
Marketable securities	1,001	824
Accounts and notes receivable (less allowance: 2003 – \$179; 2002 – \$181)	9,722	9,385
Inventories:		
Crude oil and petroleum products	2,003	2,019
Chemicals	173	193
Materials, supplies and other	472	551
	<u>2,648</u>	<u>2,763</u>
Prepaid expenses and other current assets	1,789	1,847
TOTAL CURRENT ASSETS	19,426	17,776
Long-term receivables, net	1,493	1,338
Investments and advances	12,319	11,097
Properties, plant and equipment, at cost	100,556	105,231
Less: Accumulated depreciation, depletion and amortization	<u>56,018</u>	<u>61,076</u>
	44,538	44,155
Deferred charges and other assets	2,594	2,993
Assets held for sale	1,100	–
TOTAL ASSETS	\$ 81,470	\$ 77,359
LIABILITIES AND STOCKHOLDERS' EQUITY		
Short-term debt	\$ 1,703	\$ 5,358
Accounts payable	8,675	8,455
Accrued liabilities	3,172	3,364
Federal and other taxes on income	1,392	1,626
Other taxes payable	1,169	1,073
TOTAL CURRENT LIABILITIES	16,111	19,876
Long-term debt	10,651	10,666
Capital lease obligations	243	245
Deferred credits and other noncurrent obligations	7,758	4,474
Noncurrent deferred income taxes	6,417	5,619
Reserves for employee benefit plans	3,727	4,572
Minority interests	268	303
TOTAL LIABILITIES	45,175	45,755
Preferred stock (authorized 100,000,000 shares, \$1.00 par value; none issued)	–	–
Common stock (authorized 4,000,000,000 shares, \$0.75 par value; 1,137,021,057 shares issued)	853	853
Capital in excess of par value	4,855	4,833
Retained earnings	35,315	30,942
Accumulated other comprehensive loss	(809)	(998)
Deferred compensation and benefit plan trust	(602)	(652)
Treasury stock, at cost (2003 – 67,873,337 shares; 2002 – 68,884,416 shares)	<u>(3,317)</u>	<u>(3,374)</u>
TOTAL STOCKHOLDERS' EQUITY	36,295	31,604
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	\$ 81,470	\$ 77,359

See accompanying Notes to the Consolidated Financial Statements.

	Year ended December 31		
	2003	2002	2001
OPERATING ACTIVITIES			
Net income	\$ 7,230	\$ 1,132	\$ 3,288
Adjustments			
Cumulative effect of changes in accounting principles	196	–	–
Depreciation, depletion and amortization	5,384	5,231	7,059
Write-down of investments in Dynegy, before tax	–	1,796	–
Dry hole expense	256	288	646
Distributions (less) more than income from equity affiliates	(383)	510	(489)
Net before-tax gains on asset retirements and sales	(194)	(33)	(116)
Gain from exchange of Dynegy preferred stock	(365)	–	–
Net foreign currency losses (gains)	199	5	(122)
Deferred income tax provision	164	(81)	(768)
Net decrease in operating working capital	162	1,125	643
Extraordinary before-tax loss on merger-related asset dispositions	–	–	787
Minority interest in net income	80	57	121
Decrease (increase) in long-term receivables	12	(39)	(9)
Decrease in other deferred charges	1,646	428	61
Cash contributions to employee pension plans	(1,417)	(246)	(107)
Other	(655)	(230)	481
NET CASH PROVIDED BY OPERATING ACTIVITIES	12,315	9,943	11,475
INVESTING ACTIVITIES			
Capital expenditures	(5,625)	(7,597)	(9,713)
Proceeds from asset sales	1,107	2,341	298
Proceeds from redemption of Dynegy securities	225	–	–
Net sales (purchases) of marketable securities	153	209	(183)
Net sales of other short-term investments	–	–	56
Repayment of loans by equity affiliates	68	–	–
NET CASH USED FOR INVESTING ACTIVITIES	(4,072)	(5,047)	\$(9,542)
FINANCING ACTIVITIES			
Net (payments) borrowings of short-term obligations	(3,628)	(1,810)	3,830
Proceeds from issuances of long-term debt	1,034	2,045	412
Repayments of long-term debt and other financing obligations	(1,347)	(1,356)	(2,856)
Redemption of Market Auction Preferred Shares	–	–	(300)
Redemption of preferred stock by subsidiaries	(75)	–	(463)
Issuance of preferred stock by subsidiaries	–	–	12
Cash dividends			
Common stock	(3,033)	(2,965)	(2,733)
Preferred stock	–	–	(6)
Dividends paid to minority interests	(37)	(26)	(119)
Net sales of treasury shares	57	41	110
NET CASH USED FOR FINANCING ACTIVITIES	(7,029)	(4,071)	(2,113)
EFFECT OF EXCHANGE RATE CHANGES			
ON CASH AND CASH EQUIVALENTS	95	15	(31)
NET CHANGE IN CASH AND CASH EQUIVALENTS	1,309	840	(211)
CASH AND CASH EQUIVALENTS AT JANUARY 1	2,957	2,117	2,328
CASH AND CASH EQUIVALENTS AT DECEMBER 31	\$ 4,266	\$ 2,957	\$ 2,117

See accompanying Notes to the Consolidated Financial Statements.



Consolidated Statement of Stockholders' Equity

Shares in thousands; amounts in millions of dollars

	2003		2002		2001	
	Shares	Amount	Shares	Amount	Shares	Amount
PREFERRED STOCK	–	\$ –	–	\$ –	–	\$ –
MARKET AUCTION PREFERRED SHARES						
Balance at January 1	–	–	–	–	1	300
Redemptions	–	–	–	–	(1)	(300)
BALANCE AT DECEMBER 31	–	\$ –	–	\$ –	–	\$ –
COMMON STOCK						
Balance at January 1	1,137,021	\$ 853	1,137,021	\$ 853	1,149,521	\$ 862
Retirement of Texaco treasury stock	–	–	–	–	(12,500)	(9)
Change in par value	–	–	–	–	–	–
BALANCE AT DECEMBER 31	1,137,021	\$ 853	1,137,021	\$ 853	1,137,021	\$ 853
CAPITAL IN EXCESS OF PAR						
Balance at January 1		\$ 4,833		\$ 4,811		\$ 5,505
Retirement of Texaco treasury stock		–		–		(739)
Change in common stock par value		–		–		–
Treasury stock transactions		22		22		45
BALANCE AT DECEMBER 31		\$ 4,855		\$ 4,833		\$ 4,811
RETAINED EARNINGS						
Balance at January 1		\$ 30,942		\$ 32,767		\$ 32,206
Net income		7,230		1,132		3,288
Cash dividends						
Common stock		(3,033)		(2,965)		(2,733)
Preferred stock						
Market Auction Preferred Shares		–		–		(6)
Tax benefit from dividends paid on unallocated ESOP shares and other		6		8		12
Exchange of Dynegy securities		170		–		–
BALANCE AT DECEMBER 31		\$ 35,315		\$ 30,942		\$ 32,767

See accompanying Notes to the Consolidated Financial Statements.



Consolidated Statement of Stockholders' Equity – *Continued*

Shares in thousands; amounts in millions of dollars

	2003		2002		2001	
	Shares	Amount	Shares	Amount	Shares	Amount
ACCUMULATED OTHER COMPREHENSIVE LOSS						
Currency translation adjustment						
Balance at January 1		\$ (208)		\$ (223)		\$ (212)
Change during year		32		15		(11)
Balance at December 31		\$ (176)		\$ (208)		\$ (223)
Minimum pension liability adjustment						
Balance at January 1		\$ (876)		\$ (91)		\$ (100)
Change during year		2		(785)		9
Balance at December 31		\$ (874)		\$ (876)		\$ (91)
Unrealized net holding gain on securities						
Balance at January 1		\$ 49		\$ 5		\$ 2
Change during year		80		44		3
Balance at December 31		\$ 129		\$ 49		\$ 5
Net derivatives gain on hedge transactions						
Balance at January 1		\$ 37		\$ 3		\$ –
Change during year		75		34		3
Balance at December 31		\$ 112		\$ 37		\$ 3
BALANCE AT DECEMBER 31		\$ (809)		\$ (998)		\$ (306)
DEFERRED COMPENSATION AND BENEFIT PLAN TRUST						
DEFERRED COMPENSATION						
Balance at January 1		\$ (412)		\$ (512)		\$ (681)
Net reduction of ESOP debt and other		50		100		106
Restricted stock						
Awards		–		–		(35)
Amortization and other		–		–		12
Vesting upon merger		–		–		86
BALANCE AT DECEMBER 31		(362)		(412)		(512)
BENEFIT PLAN TRUST (COMMON STOCK)	7,084	(240)	7,084	(240)	7,084	(240)
BALANCE AT DECEMBER 31	7,084	\$ (602)	7,084	\$ (652)	7,084	\$ (752)
TREASURY STOCK AT COST						
Balance at January 1	68,884	\$ (3,374)	69,800	\$ (3,415)	84,835	\$ (4,273)
Purchases	40	(3)	38	(3)	141	(9)
Retirement of Texaco treasury stock	–	–	–	–	(12,500)	748
Issuances – mainly employee benefit plans	(1,051)	60	(954)	44	(2,676)	119
BALANCE AT DECEMBER 31	67,873	\$ (3,317)	68,884	\$ (3,374)	69,800	\$ (3,415)
TOTAL STOCKHOLDERS' EQUITY AT DECEMBER 31		\$ 36,295		\$ 31,604		\$ 33,958

See accompanying Notes to the Consolidated Financial Statements.

NOTE 1.**SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**

General ChevronTexaco manages its investments in and provides administrative, financial and management support to U.S. and foreign subsidiaries and affiliates that engage in fully integrated petroleum operations, chemicals operations and coal mining activities. In addition, ChevronTexaco holds investments in power generation and gasification businesses. Collectively, these companies operate in more than 180 countries. Petroleum operations consist of exploring for, developing and producing crude oil and natural gas; refining crude oil into finished petroleum products; marketing crude oil, natural gas and the many products derived from petroleum; and transporting crude oil, natural gas and petroleum products by pipelines, marine vessels, motor equipment and rail car. Chemicals operations include the manufacture and marketing of commodity petrochemicals, plastics for industrial uses, and fuel and lube oil additives.

In preparing its Consolidated Financial Statements, the company follows accounting principles generally accepted in the United States of America. This requires the use of estimates and assumptions that affect the assets, liabilities, revenues and expenses reported in the financial statements as well as amounts included in the notes thereto, including discussion and disclosure of contingent liabilities. While the company uses its best estimates and judgments, actual results could differ from these estimates as future confirming events occur.

The nature of the company's operations and the many countries in which it operates subject it to changing economic, regulatory and political conditions. The company does not believe it is vulnerable to the risk of near-term severe impact as a result of any concentration of its activities.

Subsidiary and Affiliated Companies The Consolidated Financial Statements include the accounts of controlled subsidiary companies more than 50 percent owned. Investments in and advances to affiliates in which the company has a substantial ownership interest of approximately 20 percent to 50 percent or for which the company exercises significant influence but not control over policy decisions are accounted for by the equity method. As part of that accounting, the company recognizes gains and losses that arise from the issuance of stock by an affiliate that results in changes in the company's proportionate share of the dollar amount of the affiliate's equity currently in income. Deferred income taxes are provided for these gains and losses.

Investments are assessed for possible impairment when there are indications that the fair value of the investment may be below the company's carrying value. When such a condition is deemed to be other than temporary, the carrying value of the investment is written down to its fair value, and the amount of the write-down is included in net income. In making the determination as to whether a decline is other than temporary, the company considers such factors as the duration and extent of the decline, the investee's financial performance, and the company's ability and intention to retain its investment for a period that will be sufficient to allow for any anticipated recovery in the investment's market value. The new cost basis of investments in the common stock of these equity investees is not changed for subsequent recoveries in fair value.

Subsequent recoveries in the carrying value of other investments are reported in "Other comprehensive income."

Differences between the company's carrying value of an equity investment and its underlying equity in the net assets of the affiliate are assigned to the extent practicable to specific assets and liabilities based on the company's analysis of the various factors giving rise to the difference. The company's share of the affiliate's reported earnings is adjusted quarterly to reflect the difference between these allocated values and the affiliate's historical book values.

Derivatives The majority of the company's activity in commodity derivative instruments is intended to manage the price risk posed by physical transactions. For some of this derivative activity, generally limited to large, discrete or infrequently occurring transactions, the company may elect to apply fair value or cash flow hedge accounting. For other similar derivative instruments, generally because of the short-term nature of the contracts or their limited use, the company has elected not to apply hedge accounting, and changes in the fair value of those contracts are reflected in current income. For the company's trading activity, gains and losses from the derivative instruments are reported in current income. For derivative instruments relating to foreign currency exposures, gains and losses are reported in current income. Interest rate swaps – hedging a portion of the company's fixed-rate debt – are accounted for as fair value hedges, whereas interest rate swaps relating to a portion of the company's floating-rate debt are recorded at fair value on the Consolidated Balance Sheet with resulting gains and losses reflected in income.

Short-Term Investments All short-term investments are classified as available for sale and are in highly liquid debt or equity securities. Those investments that are part of the company's cash management portfolio with original maturities of three months or less are reported as "Cash equivalents." The balance of the short-term investments is reported as "Marketable securities." Short-term investments are marked-to-market with any unrealized gains or losses included in "Other comprehensive income."

Inventories Crude oil, petroleum products and chemicals are generally stated at cost, using a Last-In, First-Out (LIFO) method. In the aggregate, these costs are below market. "Materials, supplies and other" inventories generally are stated at average cost.

Properties, Plant and Equipment The successful efforts method is used for oil and gas exploration and production activities. All costs for development wells, related plant and equipment, proved mineral interests in oil and gas properties, and related asset retirement obligation (ARO) assets are capitalized. Costs of exploratory wells are capitalized pending determination of whether the wells found proved reserves. Costs of wells that are assigned proved reserves remain capitalized. Costs also are capitalized for wells that find commercially producible reserves that cannot be classified as proved, pending one or more of the following: (1) decisions on additional major capital expenditures, (2) the results of additional exploratory wells that are under way or firmly planned, and (3) securing final regulatory approvals for development. Otherwise, well costs are expensed if a deter-

mination as to whether proved reserves were found cannot be made within one year following completion of drilling. All other exploratory wells and costs are expensed.

Long-lived assets to be held and used, including proved oil and gas properties, are assessed for possible impairment by comparing their carrying values with the undiscounted future net before-tax cash flows. Events that can trigger assessments for possible impairments include write-downs of proved reserves based on field performance, significant decreases in the market value of an asset, significant change in the extent or manner of use, physical change in an asset, and an expectation that, more likely than not, a long-lived asset or asset group will be sold or otherwise disposed of significantly before the end of its previously estimated useful life. Impaired assets are written down to their estimated fair values, generally their discounted future net before-tax cash flows. For proved oil and gas properties in the United States, the company generally performs the impairment review on an individual field basis. Outside the United States, reviews are performed on a country, concession or field basis, as appropriate. Impairment amounts are recorded as incremental “Depreciation, depletion and amortization” expense.

Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value with the fair value less the cost to sell. If the net book value exceeds the sales value, the asset is considered impaired resulting in an adjustment to the lower value.

Effective January 1, 2003, the company implemented Financial Accounting Standards Board Statement No. 143, “Accounting for Asset Retirement Obligations” (FAS 143), in which the fair value of a liability for an asset retirement obligation is recorded as an asset and a liability when there is a legal obligation associated with the retirement of a long-lived asset and the amount can be reasonably estimated. See also Note 25 on page 74 relating to asset retirement obligations, which includes additional information on the company’s adoption of FAS 143. Previously, for oil, gas and coal producing properties, a provision was made through depreciation expense for anticipated abandonment and restoration costs at the end of the property’s useful life.

Depreciation and depletion of all capitalized costs of proved oil and gas producing properties, except mineral interests, are expensed using the unit-of-production method by individual field as the proved developed reserves are produced. Depletion expenses for capitalized costs of proved mineral interests are recognized using the unit-of-production method by individual field as the related proved reserves are produced. Periodic valuation provisions for impairment of capitalized costs of unproved mineral interests are expensed.

Depreciation and depletion expenses for coal assets are determined using the unit-of-production method as the proved reserves are produced. The capitalized costs of all other plant and equipment are depreciated or amortized over their estimated useful lives. In general, the declining-balance method is used to depreciate plant and equipment in the United States; the straight-line method generally is used to depreciate international plant and equipment and to amortize all capitalized leased assets.

Gains or losses are not recognized for normal retirements of properties, plant and equipment subject to composite group amortization or depreciation. Gains or losses from abnormal retirements are recorded as expenses and from sales as “Other income.”

Expenditures for maintenance, repairs and minor renewals to maintain facilities in operating condition are generally expensed as incurred. Major replacements and renewals are capitalized.

Environmental Expenditures Environmental expenditures that relate to ongoing operations or to conditions caused by past operations are expensed. Expenditures that create future benefits or contribute to future revenue generation are capitalized.

Liabilities related to future remediation costs are recorded when environmental assessments and/or cleanups are probable and the costs can be reasonably estimated. For the company’s U.S. and Canadian marketing facilities, the accrual is based in part on the probability that a future remediation commitment will be required. For oil, gas and coal producing properties, a liability for an asset retirement obligation is made following FAS 143, which the company implemented effective January 1, 2003. See Note 25 on page 74 related to FAS 143.

For Superfund sites, the company records a liability for its designated share of the probable and estimable costs and probable amounts for other potentially responsible parties when mandated by the regulatory agencies because the other parties are not able to pay their respective shares.

The company records the gross amount of its liability based on its best estimate of future costs using currently available technology and applying current regulations as well as the company’s own internal environmental policies. Future amounts are not discounted. Recoveries or reimbursements are recorded as assets when receipt is reasonably assured.

Currency Translation The U.S. dollar is the functional currency for substantially all of the company’s consolidated operations and those of its equity affiliates. For those operations, all gains or losses from currency translations are currently included in income. The cumulative translation effects for those few entities, both consolidated and affiliated, using functional currencies other than the U.S. dollar are included in the currency translation adjustment in “Stockholders’ equity.”

Revenue Recognition Revenues associated with sales of crude oil, natural gas, coal, petroleum and chemicals products, and all other sources are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. Revenues from natural gas production from properties in which ChevronTexaco has an interest with other producers are generally recognized on the basis of the company’s net working interest (entitlement method).

Stock Compensation At December 31, 2003, the company had stock-based employee compensation plans, which are described more fully in Note 22 beginning on page 70. The company accounts for those plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, “Accounting for Stock Issued to Employees,” and related interpretations. The following table illustrates the effect on net income and earnings per share if the company had applied the fair-value-recognition provisions of Financial Accounting Standards Board (FASB) Statement No. 123, “Accounting for Stock-Based Compensation,” to stock-based employee compensation:



NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES – Continued

	Year ended December 31		
	2003	2002	2001
Net income, as reported	\$ 7,230	\$ 1,132	\$ 3,288
Add: Stock-based employee compensation expense included in reported net income determined under APB No. 25, net of related tax effects	1	(1)	68
Deduct: Total stock-based employee compensation expense determined under fair-value-based method for all awards, net of related tax effects	(26)	(48)	(154)
Pro forma net income	\$ 7,205	\$ 1,083	\$ 3,202
Earnings per share:*			
Basic – as reported	\$ 6.97	\$ 1.07	\$ 3.10
Basic – pro forma	\$ 6.94	\$ 1.02	\$ 3.02
Diluted – as reported	\$ 6.96	\$ 1.07	\$ 3.09
Diluted – pro forma	\$ 6.93	\$ 1.02	\$ 3.01

*The amounts in 2003 include a benefit of \$0.16 for the company's share of a capital stock transaction of its Dynegy Inc. affiliate, which under the applicable accounting rules was recorded directly to the company's retained earnings and not included in net income for the period.

Basis of Presentation – Merger of Chevron and Texaco On October 9, 2001, Texaco Inc. (Texaco) became a wholly owned subsidiary of Chevron Corporation (Chevron) pursuant to a merger transaction, and Chevron changed its name to ChevronTexaco Corporation (ChevronTexaco). The combination was accounted for as a pooling of interests.

These Consolidated Financial Statements give retroactive effect to the merger, with all periods presented as if Chevron and Texaco had always been combined. Certain reclassifications have been made to conform the separate presentations of Chevron and Texaco. The reclassifications had no impact on the amount of net income or stockholders' equity.

The Consolidated Financial Statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of significant intercompany accounts and transactions. Included in the consolidation are the accounts of the Caltex Group of Companies (Caltex), a joint venture owned 50 percent each by Chevron and Texaco prior to the merger and accounted for under the equity method by both companies.

NOTE 2.

TEXACO MERGER TRANSACTION AND EXTRAORDINARY ITEM

The following table presents summarized financial data for the combined company for the period prior to the merger.

	Nine months ended September 30
	2001
Revenues and other income	
Chevron	\$ 37,213
Texaco ¹	39,469
Adjustments/eliminations ²	8,103
ChevronTexaco	\$ 84,785
Net income	
Chevron	\$ 4,092
Texaco ¹	2,214
Net income, before extraordinary item	\$ 6,306
Extraordinary loss net of income tax ³	(496)
ChevronTexaco	\$ 5,810

¹ Includes certain reclassification adjustments to conform to historical Chevron presentation.

² Consolidation of former equity operations and intercompany eliminations.

³ Loss associated with the sales of the company's interests in Equilon and Motiva.

At the time of the merger, each share of Texaco common stock was converted, on a tax-free basis, into the right to receive 0.77 shares of ChevronTexaco common stock. Approximately 425 million additional shares of common stock were issued, representing about 40 percent of the outstanding ChevronTexaco common stock after the merger.

As a condition of approving the merger, the U.S. Federal Trade Commission (FTC) required the divestment of certain Texaco assets: Texaco's investments in its U.S. refining, marketing and transportation affiliates, Equilon Enterprises LLC (Equilon) and Motiva Enterprises LLC (Motiva), as well as other interests in U.S. natural gas processing and transportation facilities and general aviation fuel marketing.

At the time of the merger, Texaco placed its interests in Equilon and Motiva in trust, as required by the FTC. Because the company no longer exercised significant influence over these investments, the associated accounting method was changed from equity to cost basis.

Net income for 2001 included a loss of \$643, net of a tax benefit of \$144 (\$0.61 per common share – diluted), related to the disposition of assets that were required as a condition of the FTC approval of the merger and other assets that were made duplicative by the merger. All such assets sold as a result of the merger provided net income of approximately \$375 in 2001. The after-tax loss on these dispositions was reported as an extraordinary item in accordance with pooling-of-interests accounting requirements.

Included in the total after-tax loss was a loss of \$564 connected with the sale of interests in Equilon and Motiva. Proceeds from the sale, which closed in February 2002, were approximately \$2,200.

NOTE 3.

SPECIAL ITEMS AND OTHER FINANCIAL INFORMATION

Net income for each period presented includes amounts categorized by the company as "special items," which management separately identifies to assist in the identification and explanation of the trend of results.

Listed in the following table are categories of these items and their net (decrease) increase to net income, after related tax effects.

NOTE 3. SPECIAL ITEMS AND OTHER FINANCIAL INFORMATION – Continued

	Year ended December 31		
	2003	2002	2001
Special Items			
Asset write-offs and revaluations			
Exploration and Production			
Impairments – United States	\$ (103)	\$ (183)	\$(1,168)
– International	(30)	(100)	(247)
Refining, Marketing and Transportation			
Impairments – United States	–	(66)	–
– International	(123)	(136)	(46)
Chemicals			
Manufacturing facility			
Impairment – United States	–	–	(32)
Other asset write-offs	–	–	(64)
All Other			
Other asset write-offs	(84)	–	(152)
	(340)	(485)	(1,709)
Asset dispositions			
Exploration and Production			
United States	77	–	49
International	32	–	–
Refining, Marketing and Transportation			
United States	37	–	–
International	(24)	–	–
	122	–	49
Tax adjustments	118	60	(5)
Environmental remediation provisions	(132)	(160)	(78)
Restructuring and reorganizations	(146)	–	–
Merger-related expenses	–	(386)	(1,136)
Extraordinary loss on merger-related asset sales	–	–	(643)
Litigation and provisions	–	(57)	–
Dynegy-related			
Impairments – equity share	(40)	(531)	–
Asset dispositions – equity share	–	(149)	–
Other	365	(1,626)	–
	325	(2,306)	–
Total Special Items	\$ (53)	\$ (3,334)	\$(3,522)

In 2003, the company recorded impairments of \$103 and \$30, respectively, for various U.S. and international oil and gas producing properties, reflecting lower expected recovery of proved reserves or a write-down to market value for assets in anticipation of sale. Impairments of \$123 on downstream assets were for the conversion of a refinery to a products terminal and a write-down to market value for assets in anticipation of sale. Also in 2003, ChevronTexaco exchanged its Dynegy Series B Preferred Stock for cash, notes and Series C Preferred Stock. The \$365 difference between the fair value of these items and the company's carrying value was included in net income.

In 2002, the company recorded write-downs of \$1,626 of its investment in Dynegy common and preferred stock and \$136 of its investment in its publicly traded Caltex Australia affiliate to their respective estimated fair values. The write-downs were required because the declines in the fair values of the investments below their carrying values were deemed to be other than temporary. Refer to Note 14 on pages 62 and 63 for additional information on the company's investment in Dynegy and Caltex Australia.

Also in 2002, impairments of \$183 were recorded for various U.S. exploration and production properties and \$100 for international projects. Impairments in 2001 included \$1,022 for the Midway Sunset Field in California – the result of a write-down in proved oil reserve quantities – upon determination of a lower-than-projected oil recovery from the field's steam injection process. A \$247 impairment of the LL-652 Field in Venezuela was also recorded in 2001 – as slower-than-expected reservoir repressurization resulted in a reduction in the projected volumes of oil recoverable during the company's remaining contract period of operation. Impairments included in "Asset write-offs and revaluations" were for assets held for use.

The aggregate effects on income statement categories from special items are reflected in the following table, including ChevronTexaco's proportionate share of special items related to equity affiliates.

	Year ended December 31		
	2003	2002	2001
Revenues and other income			
Income (loss) from equity affiliates	\$ 179	\$ (829)	\$ (123)
Other income	217	–	84
Total revenues and other income	396	(829)	(39)
Costs and other deductions			
Operating expenses	329	259	25
Selling, general and administrative expenses	146	180	139
Depreciation, depletion and amortization	286	298	2,294
Merger-related expenses	–	576	1,563
Taxes other than on income	–	–	12
Write-down of investments in Dynegy Inc.	–	1,796	–
Total costs and other deductions	761	3,109	4,033
Income before income tax expense	(365)	(3,938)	(4,072)
Income tax benefit	(312)	(604)	(1,193)
Net income before extraordinary item	\$ (53)	\$(3,334)	\$(2,879)
Extraordinary loss, net of income tax	–	–	(643)
Net income	\$ (53)	\$(3,334)	\$(3,522)

Other financial information is as follows:

	Year ended December 31		
	2003	2002	2001
Total financing interest and debt costs	\$ 549	\$ 632	\$ 955
Less: Capitalized interest	75	67	122
Interest and debt expense	\$ 474	\$ 565	\$ 833
Research and development expenses	\$ 238	\$ 221	\$ 209
Foreign currency (losses) gains*	\$ (404)	\$ (43)	\$ 191

*Includes \$(96), \$(66) and \$12 in 2003, 2002 and 2001, respectively, for the company's share of equity affiliates' foreign currency (losses) gains.

The excess of market value over the carrying value of inventories for which the LIFO method is used was \$2,106, \$1,571 and \$1,580 at December 31, 2003, 2002 and 2001, respectively. Market value is generally based on average acquisition costs for the year. LIFO profits of \$82, \$13 and \$10 were included in net income for the years 2003, 2002 and 2001, respectively.



NOTE 4.

INFORMATION RELATING TO THE CONSOLIDATED STATEMENT OF CASH FLOWS

“Net decrease in operating working capital” is composed of the following:

	Year ended December 31		
	2003	2002	2001
(Increase) decrease in accounts and notes receivable	\$ (265)	\$ (1,135)	\$ 2,472
Decrease (increase) in inventories	115	185	(294)
Decrease (increase) in prepaid expenses and other current assets	261	92	(211)
Increase (decrease) in accounts payable and accrued liabilities	242	1,845	(742)
(Decrease) increase in income and other taxes payable	(191)	138	(582)
Net decrease in operating working capital	\$ 162	\$ 1,125	\$ 643
Net cash provided by operating activities includes the following cash payments for interest and income taxes:			
Interest paid on debt (net of capitalized interest)	\$ 467	\$ 533	\$ 873
Income taxes paid	\$ 5,316	\$ 2,916	\$ 5,465
Net (purchases) sales of marketable securities consist of the following gross amounts:			
Marketable securities purchased	\$ (3,563)	\$ (5,789)	\$ (2,848)
Marketable securities sold	3,716	5,998	2,665
Net sales (purchases) of marketable securities	\$ 153	\$ 209	\$ (183)

The 2003 “Net Cash Provided by Operating Activities” includes an \$890 “Decrease in other deferred charges” and a decrease of the same amount in “Other” related to balance sheet reclassifications for certain pension-related assets and liabilities, in accordance with the requirements of FAS 87, “Employers’ Accounting for Pensions.”

The major components of “Capital expenditures” and the reconciliation of this amount to the capital and exploratory expenditures, excluding equity in affiliates, presented in the Management’s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) are detailed in the following table.

	Year ended December 31		
	2003	2002	2001
Additions to properties, plant and equipment ¹	\$ 4,953	\$ 6,262	\$ 6,445
Additions to investments	687	1,138	2,902 ²
Current-year dry-hole expenditures	132	252	418
Payments for other liabilities and assets, net	(147)	(55)	(52)
Capital expenditures	5,625	7,597	9,713
Expensed exploration expenditures	315	303	393
Payments of long-term debt and other financing obligations, net	286 ³	2	210 ³
Capital and exploratory expenditures, excluding equity affiliates	6,226	7,902	10,316
Equity in affiliates’ expenditures	1,137	1,353	1,712
Capital and exploratory expenditures, including equity affiliates	\$ 7,363	\$ 9,255	\$ 12,028

¹ Net of noncash items of \$1,183 in 2003, \$195 in 2002 and \$63 in 2001.

² Includes \$1,500 for investment in Dynegy preferred stock.

³ Deferred payments of \$210 related to 1993 acquisition of an interest in the Tengiz-chevroil joint venture were made in 2003 and 2001.

NOTE 5.

SUMMARIZED FINANCIAL DATA – CHEVRON U.S.A. INC.

Chevron U.S.A. Inc. (CUSA) is a major subsidiary of Chevron-Texaco Corporation. CUSA and its subsidiaries manage and operate most of ChevronTexaco’s U.S. businesses. Assets include those related to the exploration and production of crude oil, natural gas and natural gas liquids and those associated with the refining, marketing, supply and distribution of products derived from petroleum, other than natural gas liquids, excluding most of the regulated pipeline operations of ChevronTexaco. CUSA also holds ChevronTexaco’s investments in the CPChem joint venture and Dynegy, which are accounted for using the equity method.

During 2002 and 2003, ChevronTexaco implemented legal reorganizations in which certain ChevronTexaco subsidiaries transferred assets to or under CUSA and other ChevronTexaco companies were merged with and into CUSA. The summarized financial information for CUSA and its consolidated subsidiaries presented in the table below gives retroactive effect to the reorganization in a manner similar to a pooling of interests, with all periods presented as if the companies had always been combined and the reorganization had occurred on January 1, 2001. However, the financial information included below may not reflect the financial position and operating results in the future or the historical results in the periods presented had the reorganization actually occurred on January 1, 2001.

	Year ended December 31		
	2003	2002	2001
Sales and other operating revenues	\$ 82,845	\$ 66,910	\$ 57,576
Total costs and other deductions	78,448	68,579	56,371
Net income (loss)*	3,083	(1,895)	1,268

* 2003 net income includes a charge of \$323 million for the cumulative effect of changes in accounting principles.

	At December 31	
	2003	2002
Current assets	\$ 15,539	\$ 13,244
Other assets	21,348	24,563
Current liabilities	13,122	19,170
Other liabilities	14,136	12,977
Net equity	9,629	5,660
Memo: Total debt	\$ 9,091	\$ 8,137

CUSA's net loss of \$1,895 for 2002 included net charges of \$2,555 for asset write-downs and dispositions, of which \$2,306 was related to Dynegy.

NOTE 6.

SUMMARIZED FINANCIAL DATA – CHEVRON TRANSPORT CORPORATION LTD.

Chevron Transport Corporation Ltd. (CTC), incorporated in Bermuda, is an indirect, wholly owned subsidiary of ChevronTexaco Corporation. CTC is the principal operator of ChevronTexaco's international tanker fleet and is engaged in the marine transportation of crude oil and refined petroleum products. Most of CTC's shipping revenue is derived from providing transportation services to other ChevronTexaco companies. ChevronTexaco Corporation has guaranteed this subsidiary's obligations in connection with certain debt securities issued by a third party. Summarized financial information for CTC and its consolidated subsidiaries is presented as follows:

	Year ended December 31		
	2003	2002	2001
Sales and other operating revenues	\$ 601	\$ 850	\$ 859
Total costs and other deductions	535	922	793
Net income (loss)	50	(79)	67

	At December 31	
	2003	2002
Current assets	\$ 116	\$ 273
Other assets	338	464
Current liabilities	96	334
Other liabilities	243	344
Net equity	115	59

During 2003, CTC's paid-in capital increased by \$6 from additional capital contributions and settlements.

There were no restrictions on CTC's ability to pay dividends or make loans or advances at December 31, 2003.

NOTE 7.

STOCKHOLDERS' EQUITY

Retained earnings at December 31, 2003 and 2002, included approximately \$1,300 and \$1,600, respectively, for the company's share of undistributed earnings of equity affiliates.

Upon the merger of Chevron and Texaco, the authorized common stock of ChevronTexaco was increased from 2 billion shares of \$0.75 par value to 4 billion shares of \$0.75 par value. Under the terms of the merger agreement, approximately 425 million shares of ChevronTexaco common stock were issued in exchange for all of the outstanding shares of Texaco common stock based upon an exchange ratio of 0.77 of a ChevronTexaco share for each Texaco share. Texaco's common stock held in treasury was canceled at the effective time of the merger.

In 1998, in connection with the renewal of Chevron's Stockholder Rights Plan, Chevron declared a dividend distribution on each outstanding share of its common stock of one Right to purchase participating preferred stock. The Rights issued under the plan became exercisable, unless redeemed earlier by ChevronTexaco, if a person or group commenced a tender or exchange offer or acquired or obtained the right to acquire 10 percent or more of the outstanding shares of common stock without the prior consent of ChevronTexaco. In October 2002, the

Stockholder Rights agreement was amended so that the Rights would expire in November 2003, five years earlier than the initial expiration date in November 2008. No event made the Rights exercisable prior to their expiration in November 2003.

Until June 2001, there were 1,200 shares of Texaco cumulative variable rate preferred stock, called Market Auction Preferred Shares (MAPS), outstanding, with an aggregate value of \$300. The MAPS were redeemed in June 2001, at a liquidation preference of \$250,000 per share, plus premium and accrued and unpaid dividends.

At December 31, 2003, 30 million shares of ChevronTexaco's authorized but unissued common stock were reserved for issuance under the ChevronTexaco Corporation Long-Term Incentive Plan (LTIP), which was approved by the stockholders in 1990. Through the end of 2003, all of the plan's common stock requirements were met from the company's treasury stock, and there had been no issuances of reserved shares.

NOTE 8.

FINANCIAL AND DERIVATIVE INSTRUMENTS

Commodity Derivative Instruments ChevronTexaco is exposed to market risks related to price volatility of crude oil, refined products, natural gas and refinery feedstock.

The company uses derivative commodity instruments to manage this exposure on a small portion of its activity, including: firm commitments and anticipated transactions for the purchase or sale of crude oil; feedstock purchases for company refineries; crude oil and refined products inventories; and fixed-price contracts to sell natural gas and natural gas liquids.

The company also uses derivative commodity instruments for limited trading purposes.

The company maintains a policy of requiring that an International Swaps and Derivatives Association Agreement govern derivative contracts with certain counterparties to mitigate credit risk. Depending on the nature of the derivative transaction, bilateral collateral arrangements may also be required. When the company is engaged in more than one outstanding derivative transaction with the same counterparty and also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of the company's credit risk. It is the company's policy to use other netting agreements with certain counterparties with which it conducts significant transactions.

The fair values of the outstanding contracts are reported on the Consolidated Balance Sheet as "Accounts and notes receivable," "Accounts payable," "Long-term receivables – net," and "Deferred credits and other noncurrent obligations." Gains and losses on the company's risk management activities are reported as either "Sales and other operating revenues" or "Purchased crude oil and products," whereas trading gains and losses are reported as "Other income." These activities are reported under "Operating activities" in the Consolidated Statement of Cash Flows.

Foreign Currency The company enters into forward exchange contracts, generally with terms of 180 days or less, to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments, forecasted to occur within 180 days. The forward exchange contracts are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.



NOTE 8. FINANCIAL AND DERIVATIVE INSTRUMENTS – Continued

The fair values of the outstanding contracts are reported on the Consolidated Balance Sheet as “Accounts and notes receivable” or “Accounts payable,” with gains and losses reported as “Other income.” These activities are reported under “Operating activities” in the Consolidated Statement of Cash Flows.

Interest Rates The company enters into interest rate swaps as part of its overall strategy to manage the interest rate risk on its debt. Under the terms of the swaps, net cash settlements are based on the difference between fixed-rate and floating-rate interest amounts calculated by reference to agreed notional principal amounts. Interest rate swaps related to a portion of the company’s fixed-rate debt are accounted for as fair value hedges, whereas interest rate swaps related to a portion of the company’s floating-rate debt are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

During 2003, no new swaps were initiated. At year-end 2003, the interest rate swaps outstanding related to fixed-rate debt, and their weighted average maturity was approximately 4.6 years.

Fair values of the interest rate swaps are reported on the Consolidated Balance Sheet as “Accounts and notes receivable” or “Accounts payable,” with gains and losses reported directly in income as part of “Interest and debt expense.” These activities are reported under “Operating activities” in the Consolidated Statement of Cash Flows.

Fair Value Fair values are derived either from quoted market prices or, if not available, the present value of the expected cash flows. The fair values reflect the cash that would have been received or paid if the instruments were settled at year-end.

Long-term debt of \$7,229 and \$7,296 had estimated fair values of \$7,709 and \$7,971 at December 31, 2003 and 2002, respectively.

For interest rate swaps, the notional principal amounts of \$665 and \$665 had estimated fair values of \$65 and \$70 at December 31, 2003 and 2002, respectively.

The company holds cash equivalents and U.S. dollar marketable securities in domestic and offshore portfolios. Eurodollar bonds, floating-rate notes, time deposits and commercial paper are the primary instruments held. Cash equivalents and marketable securities had fair values of \$3,803 and \$2,506 at December 31, 2003 and 2002, respectively. Of these balances, \$2,803 and \$1,682 at the respective year-ends were classified as cash equivalents that had average maturities under 90 days. The remainder, classified as marketable securities, had average maturities of approximately 3.5 years.

Concentrations of Credit Risk The company’s financial instruments that are exposed to concentrations of credit risk consist primarily of its cash equivalents, marketable securities, derivative financial instruments and trade receivables. The company’s short-term investments are placed with a wide array of financial institutions with high credit ratings. This diversified investment policy limits the company’s exposure both to credit risk and to concentrations of credit risk. Similar standards of diversity and creditworthiness are applied to the company’s counterparties in derivative instruments.

The trade receivable balances, reflecting the company’s diversified sources of revenue, are dispersed among the company’s broad customer base worldwide. As a consequence, concentrations of credit risk are limited. The company routinely assesses the financial strength of its customers. When the financial strength of a customer is not considered sufficient, Letters of Credit are the principal security obtained to support lines of credit.

Investment in Dynegey Notes and Preferred Stock At the beginning of 2003, the company held \$1,500 aggregate principal amount of Dynegey Series B Preferred Stock, which was due for redemption at par value in November 2003. In August, the company exchanged its preferred stock for \$225 in cash, \$225 face value of Dynegey Junior Unsecured Subordinated Notes due 2016 and \$400 face value of Dynegey Series C Convertible Preferred Stock with a stated maturity of 2033.

The company recorded the Junior Notes and Series C Preferred Stock on the date of exchange at their fair values of \$170 and \$270, respectively, for a total of \$440. Together with the \$225 cash, the total amount recorded on the date of exchange was \$665. A gain of \$365 was included in net income at that date for the difference between the \$665 fair value received and the net balance sheet amount of \$300 associated with the Series B shares.

At December 31, 2003, the estimated fair values of the Junior Notes and Series C shares totaled \$530. The \$90 difference from the \$440 recorded in August was recorded to “Investments and advances,” with an offsetting amount in “Other comprehensive income.” Future temporary changes in the estimated fair values of the new securities likewise will be reported in “Other comprehensive income.” However, if any future decline in fair value is deemed to be other than temporary, a charge against income in the period would be recorded. Interest that accrues on the notes and dividends payable on the preferred stock is recognized in income each period.

NOTE 9.**OPERATING SEGMENTS AND GEOGRAPHIC DATA**

ChevronTexaco separately manages its exploration and production; refining, marketing and transportation; and chemicals businesses. “All Other” activities include the company’s investment in Dynegey, coal mining operations, power and gasification businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, technology companies, and expenses and net losses associated with the Chevron and Texaco merger. The company’s primary country of operation is the United States of America, its country of domicile. Other components of the company’s operations are reported as “International” (outside the United States).

Segment Earnings The company evaluates the performance of its operating segments on an after-tax basis, without considering the effects of debt financing interest expense or investment interest income, both of which are managed by the company on a worldwide basis. Corporate administrative costs and assets are not allocated to the operating segments. However, operating segments are billed for the direct use of corporate services. Non-billable costs and merger-related items remain at the corporate level. Included in net income for 2003 were net charges of \$196 for the cumulative effect of accounting principle changes, primarily relating to a new accounting standard for recognizing asset retirement obligations. The net amount was composed of

NOTE 9. OPERATING SEGMENTS AND GEOGRAPHIC DATA – Continued

\$350 of charges for U.S. Exploration and Production and credits of \$145 and \$9 for International Exploration and Production and All Other, respectively. After-tax segment income (loss) is presented in the following table:

	Year ended December 31		
	2003	2002	2001
Exploration and Production			
United States	\$ 2,833	\$ 1,717	\$ 1,779
International	3,365	2,839	2,533
Total Exploration and Production	6,198	4,556	4,312
Refining, Marketing and Transportation			
United States	482	(398)	1,254
International	685	31	560
Total Refining, Marketing and Transportation	1,167	(367)	1,814
Chemicals			
United States	5	13	(186)
International	64	73	58
Total Chemicals	69	86	(128)
Total Segment Income	7,434	4,275	5,998
Merger-related expenses	–	(386)	(1,136)
Extraordinary loss	–	–	(643)
Interest expense	(352)	(406)	(552)
Interest income	75	72	147
Other	73	(2,423)	(526)
Net Income	\$ 7,230	\$ 1,132	\$ 3,288

Segment Assets Segment assets do not include intercompany investments or intercompany receivables. Segment assets at year-end 2003 and 2002 follow:

	At December 31	
	2003	2002
Exploration and Production		
United States	\$ 12,501	\$ 11,671
International	28,520	26,172
Total Exploration and Production	41,021	37,843
Refining, Marketing and Transportation		
United States	9,354	9,681
International	17,627	17,699
Total Refining, Marketing and Transportation	26,981	27,380
Chemicals		
United States	2,165	2,154
International	662	698
Total Chemicals	2,827	2,852
Total Segment Assets	70,829	68,075
All Other		
United States	6,644	5,364
International	3,997	3,920
Total All Other	10,641	9,284
Total Assets – United States	30,664	28,870
Total Assets – International	50,806	48,489
Total Assets	\$ 81,470	\$ 77,359

Segment Sales and Other Operating Revenues Operating segment sales and other operating revenues, including internal transfers, for the years 2003, 2002 and 2001 are presented in the following table. Sales from the transfer of products between segments are at prices that approximate market prices.

Revenues for the exploration and production segment are derived primarily from the production of crude oil and natural gas, as well as the sale of third-party production of natural gas. Revenues for the refining, marketing and transportation segment are derived from the refining and marketing of petroleum products, such as gasoline, jet fuel, gas oils, kerosene, lubricants, residual fuel oils and other products derived from crude oil. This segment also generates revenues from the transportation and trading of crude oil and refined products. Chemicals segment revenues are derived from the manufacture and sale of lube oil and fuel additives. Revenues from “All Other” activities include coal mining operations, power and gasification businesses, insurance operations, real estate activities, and technology companies.

Other than the United States, the only country where Chevron-Texaco generates significant revenues is the United Kingdom, where revenues amounted to \$12,121, \$10,816 and \$10,350 in 2003, 2002 and 2001, respectively.



NOTE 9. OPERATING SEGMENTS AND GEOGRAPHIC DATA – Continued

	Year ended December 31		
	2003	2002	2001
Exploration and Production			
United States	\$ 6,928	\$ 4,998	\$ 12,744
Intersegment	6,295	4,217	2,923
Total United States	13,223	9,215	15,667
International	7,384	5,637	9,127
Intersegment	8,142	8,377	7,376
Total International	15,526	14,014	16,503
Total Exploration and Production	28,749	23,229	32,170
Refining, Marketing and Transportation			
United States	44,701	33,880	29,294
Excise taxes	3,744	3,990	3,954
Intersegment	219	163	392
Total United States	48,664	38,033	33,640
International	52,486	45,759	45,248
Excise taxes	3,342	3,006	2,580
Intersegment	–	43	452
Total International	55,828	48,808	48,280
Total Refining, Marketing and Transportation	104,492	86,841	81,920
Chemicals			
United States	323	323	335
Intersegment	129	109	89
Total United States	452	432	424
International	677	638	670
Excise taxes	9	10	12
Intersegment	83	68	65
Total International	769	716	747
Total Chemicals	1,221	1,148	1,171
All Other			
United States	338	413	408
Intersegment	121	105	60
Total United States	459	518	468
International	100	37	37
Intersegment	4	–	9
Total International	104	37	46
Total All Other	563	555	514
Segment Sales and Other			
Operating revenues			
United States	62,798	48,198	50,199
International	72,227	63,575	65,576
Total Segment Sales and Other			
Operating revenues	135,025	111,773	115,775
Elimination of intersegment sales	(14,993)	(13,082)	(11,366)
Total Sales and Other Operating Revenues	\$ 120,032	\$ 98,691	\$ 104,409

Segment Income Taxes Segment income tax expenses for the years 2003, 2002 and 2001 are as follows:

	Year ended December 31		
	2003 ¹	2002	2001
Exploration and Production			
United States	\$ 1,867	\$ 862	\$ 965
International	3,867	3,433	3,569
Total Exploration and Production	5,734	4,295	4,534
Refining, Marketing and Transportation			
United States	300	(254)	744
International	275	138	260
Total Refining, Marketing and Transportation	575	(116)	1,004
Chemicals			
United States	(25)	(17)	(78)
International	6	17	23
Total Chemicals	(19)	–	(55)
All Other ²	(946)	(1,155)	(1,123)
Total Income Tax Expense ²	\$ 5,344	\$ 3,024	\$ 4,360

¹ See Note 25 on page 74 for information concerning the cumulative effect of changes in accounting principles due to the adoption of FAS 143, "Accounting for Asset Retirement Obligations."

² 2001 excludes tax of \$144 for extraordinary item.

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 14 beginning on page 62. Information related to properties, plant and equipment by segment is contained in Note 15 on page 64.

NOTE 10. LITIGATION

Unocal Patent Chevron, Texaco and four other oil companies (refiners) filed suit in 1995, contesting the validity of a patent ('393' patent) granted to Unocal Corporation (Unocal) for certain reformulated gasoline blends. ChevronTexaco sells reformulated gasolines in California in certain months of the year.

In March 2000, the U.S. Court of Appeals for the Federal Circuit upheld a September 1998 District Court decision that Unocal's patent was valid and enforceable and assessed damages of 5.75 cents per gallon for gasoline produced during the summer of 1996 that infringed on the claims of the patent.

In February 2001, the U.S. Supreme Court concluded it would not review the lower court's ruling, and the case was sent back to the District Court for an accounting of all infringing gasoline produced after August 1, 1996. The District Court ruled that the per-gallon damages awarded by the jury are limited to infringement that occurs in California only. Additionally, the U.S. Patent and Trademark Office (USPTO) granted three petitions by the refiners to re-examine the validity of Unocal's '393' patent and has twice rejected all of the claims in the '393' patent. Those rejections have been appealed by Unocal to the USPTO Board of Appeals. The District Court judge requested further briefing and advised that she would not enter a final judgment in this case until the USPTO had completed its re-examination of the '393' patent.

During 2002 and 2003, the USPTO granted two petitions for re-examination of another Unocal patent, the '126' patent. The USPTO has rejected the validity of the claims of the '126' patent, which could affect a larger share of U.S. gasoline production. Separately, in March 2003, the Federal Trade Commission (FTC)

filed a complaint against Unocal alleging that its conduct during the pendency of the patents was in violation of antitrust law. In November 2003, the Administrative Law Judge dismissed the complaint brought by the FTC. The FTC has appealed the decision.

Unocal has obtained additional patents that could affect a larger share of U.S. gasoline production. ChevronTexaco believes these additional patents are invalid, unenforceable and/or not infringed. The company's financial exposure in the event of unfavorable conclusions to the patent litigation and regulatory reviews may include royalties, plus interest, for production of gasoline that is proved to have infringed the patents. The competitive and financial effects on the company's refining and marketing operations, although presently indeterminable, could be material. ChevronTexaco has been accruing in the normal course of business any future estimated liability for potential infringement of the '393' patent covered by the 1998 trial court's ruling.

In 2000, prior to the merger, Chevron and Texaco made payments to Unocal totaling approximately \$30 million for the original court ruling, including interest and fees.

MTBE Another issue involving the company is the petroleum industry's use of methyl tertiary butyl ether (MTBE) as a gasoline additive and its potential environmental impact through seepage into groundwater.

Along with other oil companies, the company is a party to more than 60 lawsuits and claims related to the use of the chemical MTBE in certain oxygenated gasolines. These actions may require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future.

The company's ultimate exposure related to these lawsuits and claims is not currently determinable, but could be material to net income in any one period. ChevronTexaco has reduced the use of MTBE in gasoline it manufactures in the United States, including the complete phase-out of MTBE in California before the end of 2003.

NOTE 11.

LEASE COMMITMENTS

Certain noncancelable leases are classified as capital leases, and the leased assets are included as part of "Properties, plant and equipment, at cost." Such leasing arrangements involve tanker charters, crude oil production and processing equipment, service stations, and other facilities. Other leases are classified as operating leases and are not capitalized. The payments on such leases are recorded as expense. Details of the capitalized leased assets are as follows:

	At December 31	
	2003	2002
Exploration and Production	\$ 246	\$ 176
Refining, Marketing and Transportation	842	843
Total	1,088	1,019
Less: Accumulated amortization	642	595
Net capitalized leased assets	\$ 446	\$ 424

Rental expenses incurred for operating leases during 2003, 2002 and 2001 were as follows:

	Year ended December 31		
	2003	2002	2001
Minimum rentals	\$ 1,567	\$ 1,270	\$ 1,132
Contingent rentals	3	4	14
Total	1,570	1,274	1,146
Less: Sublease rental income	48	53	76
Net rental expense	\$ 1,522	\$ 1,221	\$ 1,070

Contingent rentals are based on factors other than the passage of time, principally sales volumes at leased service stations. Certain leases include escalation clauses for adjusting rentals to reflect changes in price indices, renewal options ranging from one to 25 years, and/or options to purchase the leased property during or at the end of the initial or renewal lease period for the fair market value or other specified amount at that time.

At December 31, 2003, the estimated future minimum lease payments (net of noncancelable sublease rentals) under operating and capital leases, which at inception had a noncancelable term of more than one year, were as follows:

	At December 31	
	Operating Leases	Capital Leases
Year: 2004	\$ 299	\$ 98
2005	288	66
2006	260	65
2007	206	58
2008	181	48
Thereafter	800	547
Total	\$ 2,034	\$ 882
Less: Amounts representing interest and executory costs		269
Net present values		613
Less: Capital lease obligations included in short-term debt		370
Long-term capital lease obligations		\$ 243

NOTE 12.

RESTRUCTURING AND REORGANIZATION COSTS

In connection with various reorganizations and restructurings across several businesses and corporate departments, during 2003 the company recorded before-tax charges of \$258 (\$146 after tax) for estimated termination benefits for approximately 4,500 employees. Nearly half of the liability related to the global downstream business, including the effect of its reorganization along functional lines rather than the geographic configuration used previously. Substantially all of the employee reductions are expected to occur by early 2005.

Activity for the company's liability related to reorganizations and restructurings in 2003 is summarized in the following table:

Amounts before tax	Amount
Balance at January 1, 2003	\$ 6
Additions	258
Payments	(24)
Balance at December 31, 2003	\$ 240

An approximate \$100 liability remained for employee severance charges recorded in 2002 and 2001. The balance related primarily to deferred payment options elected by certain employees who terminated before the end of 2003 and were paid in January 2004.



NOTE 13.

ASSETS HELD FOR SALE

At December 31, 2003, the company classified \$1,100 of net properties, plant and equipment as "Assets held for sale" on the Consolidated Balance Sheet. The asset dispositions are expected to occur during 2004, substantially all of which related to the U.S. upstream business segment.

These anticipated sales, consisting of interests in several hundred individual properties, relate to the company's plan to dispose of certain assets in the overall portfolio that do not provide sufficient long-term value.

No significant gains or losses were recorded in 2003 for the held-for-sale assets. Revenues and earnings associated with the assets were likewise insignificant in 2003 and earlier years.

NOTE 14.

INVESTMENTS AND ADVANCES

Equity in earnings, together with investments in and advances to companies accounted for using the equity method and other investments accounted for at or below cost, are as follows:

	Investments and Advances		Equity in Earnings		
	At December 31		Year ended December 31		
	2003	2002	2003	2002	2001
Exploration and Production					
Tengizchevroil	\$ 3,363	\$ 2,949	\$ 611	\$ 490	\$ 332
Other	991	876	200	116	205
Total Exploration and Production	4,354	3,825	811	606	537
Refining, Marketing and Transportation					
Equilon*	—	—	—	—	274
Motiva*	—	—	—	—	276
LG-Caltex Oil Corporation	1,561	1,513	107	46	60
Caspian Pipeline Consortium	1,026	1,014	52	66	38
Star Petroleum Refining Company Ltd.	457	449	8	(25)	(56)
Caltex Australia Ltd.	118	109	13	(156)	16
Other	1,069	994	100	110	92
Total Refining, Marketing and Transportation	4,231	4,079	280	41	700
Chemicals					
Chevron Phillips Chemical Company LLC	1,747	1,710	24	2	(229)
Other	20	21	1	4	2
Total Chemicals	1,767	1,731	25	6	(227)
All Other					
Dynergy Inc.	698	347	(56)	(679)	188
Other	761	681	(31)	1	(54)
Total equity method	\$ 11,811	\$ 10,663	\$ 1,029	\$ (25)	\$ 1,144
Other at or below cost	508	434			
Total investments and advances	\$ 12,319	\$ 11,097			
Total U.S.	\$ 3,905	\$ 3,216	\$ 175	\$ (559)	\$ 693
Total International	\$ 8,414	\$ 7,881	\$ 854	\$ 534	\$ 451

* Placed in trust at the time of the merger and accounting changed from the equity method to the cost basis.

Descriptions of major affiliates are as follows:

Tengizchevroil ChevronTexaco has a 50 percent equity ownership interest in Tengizchevroil (TCO), a joint venture formed in 1993 to develop the Tengiz and Korolev oil fields in Kazakhstan over a 40-year period. Upon formation of the joint venture, the company incurred an obligation of \$420, payable to the Republic of Kazakhstan upon attainment of a dedicated export system with the capability of the greater of 260,000 barrels of oil per day or TCO's production capacity. As a part of the 2001 transaction, the company paid \$210 of the \$420 obligation. An additional \$210 was paid in 2003 to settle the remaining obligation. The \$420 was also included in the carrying value of the original investment, as the company believed, beyond a reasonable doubt, that its full payment would be made.

Equilon Enterprises LLC and Motiva Enterprises LLC Until February 2002, the company had equity interests in Equilon and Motiva – joint ventures engaged in U.S. refining and marketing activities. Under mandate of the FTC as a condition of the merger, the company's ownership interests were placed in trust on October 9, 2001. The trust completed the dispositions of the company's investments in Equilon and Motiva in February 2002. See Note 2 on page 54 for additional information on Equilon and Motiva.

LG-Caltex Oil Corporation ChevronTexaco owns 50 percent of LG-Caltex, a joint venture formed in 1967 between the LG Group and Caltex to engage in importing, refining and marketing of petroleum products and petrochemicals in South Korea.

Star Petroleum Refining Company Ltd. ChevronTexaco has a 64 percent equity ownership interest in Star Petroleum Refining Company Limited (SPRC), which owns the Star Refinery at Map Ta Phut, Thailand. The Petroleum Authority of Thailand owns the remaining 36 percent of SPRC.

Caltex Australia Ltd. ChevronTexaco has a 50 percent equity ownership interest in Caltex Australia Limited (CAL). The remaining 50 percent of CAL is publicly owned. During 2002, the company wrote down its investment in CAL by \$136 to its estimated fair value at September 30, 2002. At December 31, 2003, the fair value of ChevronTexaco's share of CAL common stock was \$465. The aggregate carrying value of the company's investment in CAL was approximately \$90 lower than the amount of underlying equity in CAL net assets.

Chevron Phillips Chemical Company LLC ChevronTexaco owns 50 percent of CPChem, formed in July 2000 when Chevron merged most of its petrochemicals businesses with those of Phillips Petroleum Company. Because CPChem is a limited liability company, ChevronTexaco records the provision for income taxes and related tax liability applicable to its share of the venture's income separately in its consolidated financial statements. At December 31, 2003, the company's carrying value of its investment in CPChem was approximately \$130 lower than the amount of underlying equity in CPChem's net assets.

Dynergy Inc. ChevronTexaco owns an approximate 26 percent equity interest in the common stock of Dynergy, an energy merchant engaged in power generation, natural gas liquids processing and marketing, and regulated energy delivery. The company also holds investments in Dynergy notes and preferred stock.

Investment in Dynege Common Stock At December 31, 2003, the carrying value of the company's investment in Dynege common stock was approximately \$150. This amount was about \$425 below the company's proportionate interest in Dynege's underlying net assets. This difference resulted from write-downs of the investment in 2002 for declines in the market value of the common shares below the company's carrying value that were deemed to be other than temporary. The approximate \$425 difference has been assigned to the extent practicable to specific Dynege assets and liabilities, based upon the company's analysis of the various factors giving rise to the decline in value of the Dynege shares. The company's equity share of Dynege's reported earnings is adjusted quarterly to reflect the difference between these allocated values and Dynege's historical book values. The

market value of the company's investment in Dynege's common stock at December 31, 2003, was \$415.

Investments in Dynege Notes and Preferred Stock Refer to Note 8 on page 58 for a discussion of these investments.

Other Information "Sales and other operating revenues" on the Consolidated Statement of Income includes \$6,308, \$6,522 and \$15,238 with affiliated companies for 2003, 2002 and 2001, respectively. "Purchased crude oil and products" includes \$1,740, \$1,839 and \$4,069 with affiliated companies for 2003, 2002 and 2001, respectively.

"Accounts and notes receivable" on the Consolidated Balance Sheet includes \$827 and \$615 due from affiliated companies at December 31, 2003 and 2002, respectively. "Accounts payable" includes \$118 and \$161 due to affiliated companies at December 31, 2003 and 2002, respectively.

The following table provides summarized financial information on a 100 percent basis for Equilon, Motiva and all other equity affiliates, as well as ChevronTexaco's total share.

Year ended December 31	Equilon ¹			Motiva ¹			Other Affiliates			ChevronTexaco Share ^{2,3}		
	2003	2002	2001	2003	2002	2001	2003	2002	2001	2003	2002	2001
Total revenues	\$ –	\$ –	\$36,501	\$ –	\$ –	\$14,459	\$42,323	\$31,877	\$69,549	\$19,467	\$15,049	\$46,649
Income (loss) before income tax expense	–	–	604	–	–	771	1,657	(1,517)	646	1,211	70	1,430
Net income (loss)	–	–	397	–	–	486	1,508	(1,540)	(74)	1,029	(25)	1,144
At December 31												
Current assets	\$ –	\$ –	\$ –	\$ –	\$ –	\$ –	\$12,204	\$16,808	\$17,015	\$5,180	\$6,270	\$5,922
Noncurrent assets	–	–	–	–	–	–	39,422	40,884	40,191	15,765	15,219	16,276
Current liabilities	–	–	–	–	–	–	9,642	14,414	14,688	4,132	5,158	4,757
Noncurrent liabilities	–	–	–	–	–	–	22,738	24,129	23,255	5,002	5,668	5,600
Net equity	\$ –	\$ –	\$ –	\$ –	\$ –	\$ –	\$19,246	\$19,149	\$19,263	\$11,811	\$10,663	\$11,841

¹ Accounted for under the equity method pre-merger and the cost basis post-merger.

² The company's share of income and underlying equity in the net assets of its investments includes the effects of write-downs of certain investments – largely related to Dynege Inc. and Caltex Australia Ltd., as described in the preceding section.

³ 2002 conformed to the 2003 presentation.



NOTE 15.
PROPERTIES, PLANT AND EQUIPMENT¹

	At December 31						Year ended December 31					
	Gross Investment at Cost			Net Investment ²			Additions at Cost ³			Depreciation Expense		
	2003	2002	2001	2003	2002	2001	2003	2002	2001	2003	2002	2001
Exploration and Production												
United States	\$ 34,798	\$ 39,986	\$ 38,582	\$ 9,953	\$ 10,457	\$ 10,560	\$ 1,776	\$ 1,658	\$ 1,973	\$ 1,815	\$ 1,806	\$ 3,508
International	37,402	36,382	33,273	20,572	18,908	17,743	3,246	3,343	2,900	2,227	2,132	2,085
Total Exploration and Production	72,200	76,368	71,855	30,525	29,365	28,303	5,022	5,001	4,873	4,042	3,938	5,593
Refining, Marketing and Transportation												
United States	12,959	13,423	12,944	5,881	6,296	6,237	389	671	626	493	570	476
International	11,174	11,194	10,878	5,944	6,310	6,349	388	411	566	655	530	555
Total Refining, Marketing and Transportation	24,133	24,617	23,822	11,825	12,606	12,586	777	1,082	1,192	1,148	1,100	1,031
Chemicals												
United States	613	614	602	303	317	321	12	16	10	21	21	22
International	719	731	698	404	420	405	24	37	31	38	21	19
Total Chemicals	1,332	1,345	1,300	707	737	726	36	53	41	59	42	41
All Other⁴												
United States	2,772	2,783	2,826	1,393	1,334	1,249	169	230	171	109	149	385
International	119	118	57	88	113	18	8	55	3	26	2	9
Total All Other	2,891	2,901	2,883	1,481	1,447	1,267	177	285	174	135	151	394
Total United States	51,142	56,806	54,954	17,530	18,404	18,367	2,346	2,575	2,780	2,438	2,546	4,391
Total International	49,414	48,425	44,906	27,008	25,751	24,515	3,666	3,846	3,500	2,946	2,685	2,668
Total	\$ 100,556	\$ 105,231	\$ 99,860	\$ 44,538	\$ 44,155	\$ 42,882	\$ 6,012	\$ 6,421	\$ 6,280	\$ 5,384	\$ 5,231	\$ 7,059

¹ Refer to Note 25 on page 74 for a discussion of the effect on 2003 PP&E balances and depreciation expenses related to the adoption of FAS 143, "Accounting for Asset Retirement Obligations."

² Net of accumulated abandonment and restoration costs of \$2,263 and \$2,155 at December 31, 2002 and 2001, respectively.

³ Net of dry hole expense related to prior years' expenditures of \$124, \$36 and \$228 in 2003, 2002 and 2001, respectively.

⁴ Primarily coal, real estate assets and management information systems.

NOTE 16.
TAXES

	Year ended December 31		
	2003	2002	2001
Taxes on income			
U.S. federal			
Current	\$ 1,147	\$ (72)	\$ 946
Deferred	121	(414)	(643)
State and local	133	21	276
Total United States	1,401	(465)	579
International			
Current	3,900	3,156	3,764
Deferred	43	333	17
Total International	3,943	3,489	3,781
Total taxes on income	\$ 5,344	\$ 3,024	\$ 4,360

In 2003, the before-tax income, including related corporate and other charges, for U.S. operations was \$5,701, compared with a before-tax loss of \$2,140 in 2002 and before-tax income of \$1,778 in 2001. For international operations, before-tax income was \$7,069, \$6,296 and \$6,513 in 2003, 2002 and 2001, respectively. U.S. federal income tax expense was reduced by \$196, \$208 and \$202 in 2003, 2002 and 2001, respectively, for business tax credits.

The preceding table does not include a U.S. deferred tax benefit of \$191 and a foreign deferred tax expense of \$170 associ-

ated with the adoption of FAS 143, and the related cumulative effect of change in accounting principle.

The table also does not include a current U.S. tax benefit of \$2 and a U.S. deferred tax benefit of \$142 associated with the extraordinary item in 2001.

The company's effective income tax rate varied from the U.S. statutory federal income tax rate because of the following:

	Year ended December 31		
	2003	2002	2001
U.S. statutory federal income tax rate	35.0%	35.0%	35.0%
Effect of income taxes from international operations in excess of taxes at the U.S. statutory rate	12.1	29.6	19.0
State and local taxes on income, net of U.S. federal income tax benefit	0.5	1.1	2.2
Prior-year tax adjustments	(1.6)	(7.0)	1.1
Tax credits	(1.5)	(5.0)	(2.4)
Effects of enacted changes in tax laws/rates on deferred tax liabilities	0.3	2.0	–
Impairment of investments in equity affiliates	–	12.4	–
Other	(1.9)	–	(1.7)
Consolidated companies	42.9	68.1	53.2
Effect of recording income from certain equity affiliates on an after-tax basis	(1.1)	4.7	(0.6)
Effective tax rate	41.8%	72.8%	52.6%

In 2003, the effective tax rate was about 42 percent. The decrease in the effective tax rate in 2003 compared with 2002 resulted from a lower proportion of international taxable income, which is taxed at higher rates than U.S. taxable income, and the absence in 2003 of the 2002 tax effects of the capital losses discussed in the next paragraph.

The increase in the 2002 effective tax rate from 2001 was due to a number of factors. One reason was that U.S. before-tax income (generally subject to a lower tax rate) was a significantly smaller percentage of overall before-tax income in 2002. Another major factor was that the impairment of the investments in Dynegy and Caltex Australia were capital losses for which no offsetting capital gains were available.

The company records its deferred taxes on a tax-jurisdiction basis and classifies those net amounts as current or noncurrent based on the balance sheet classification of the related assets or liabilities.

The reported deferred tax balances are composed of the following:

	At December 31	
	2003	2002
Deferred tax liabilities		
Properties, plant and equipment	\$ 8,796	\$ 7,818
Inventory	(57)	14
Investments and other	602	521
Total deferred tax liabilities	9,341	8,353
Deferred tax assets		
Abandonment/environmental reserves	(1,221)	(902)
Employee benefits	(1,272)	(1,414)
Tax loss carryforwards	(956)	(747)
AMT/other tax credits	(352)	(380)
Other accrued liabilities	(199)	(234)
Miscellaneous	(2,034)	(1,927)
Total deferred tax assets	(6,034)	(5,604)
Deferred tax assets valuation allowance	1,553	1,740
Total deferred taxes, net	\$ 4,860	\$ 4,489

The valuation allowance relates to foreign tax credit carryforwards, tax loss carryforwards and temporary differences for which no benefit is expected to be realized. The decrease in the valuation allowance relates primarily to the expiration of foreign tax credits and to the release of the valuation allowance on certain net operating losses, which management believes will now be realized. Tax loss carryforwards exist in many foreign jurisdictions and expire at various times beginning 2004 through 2010. However, some of these tax loss carryforwards do not have an expiration date.

At December 31, 2003 and 2002, deferred taxes were classified in the Consolidated Balance Sheet as follows:

	At December 31	
	2003	2002
Prepaid expenses and other current assets	\$ (940)	\$ (760)
Deferred charges and other assets	(641)	(455)
Federal and other taxes on income	24	85
Noncurrent deferred income taxes	6,417	5,619
Total deferred income taxes, net	\$ 4,860	\$ 4,489

It is the company's policy for subsidiaries included in the U.S. consolidated tax return to record income tax expense as though they filed separately, with the parent recording the adjustment to income tax expense for the effects of consolidation. Income taxes are accrued for retained earnings of international subsidiaries and corporate joint ventures intended to be remitted. Income taxes are not accrued for unremitted earnings of international operations that have been or are intended to be reinvested indefinitely.

Undistributed earnings of international consolidated subsidiaries and affiliates for which no deferred income tax provision has been made for possible future remittances totaled approximately \$10,541 at December 31, 2003. Substantially all of this amount represents earnings reinvested as part of the company's ongoing business. It is not practicable to estimate the amount of taxes that might be payable on the eventual remittance of such earnings. On remittance, certain countries impose withholding taxes that, subject to certain limitations, are then available for use as tax credits against a U.S. tax liability, if any.

Taxes other than on income were as follows:

	Year ended December 31		
	2003	2002	2001
United States			
Excise taxes on products and merchandise	\$ 3,744	\$ 3,990	\$ 3,954
Import duties and other levies	11	12	8
Property and other miscellaneous taxes	309	348	410
Payroll taxes	138	141	148
Taxes on production	244	179	225
Total United States	4,446	4,670	4,745
International			
Excise taxes on products and merchandise	3,351	3,016	2,592
Import duties and other levies	9,652	8,587	7,461
Property and other miscellaneous taxes	320	291	268
Payroll taxes	54	46	79
Taxes on production	83	79	11
Total International	13,460	12,019	10,411
Total taxes other than on income	\$ 17,906	\$ 16,689	\$ 15,156

NOTE 17. SHORT-TERM DEBT

	At December 31	
	2003	2002
Commercial paper*	\$ 4,078	\$ 7,183
Notes payable to banks and others with originating terms of one year or less	190	713
Current maturities of long-term debt	863	740
Current maturities of long-term capital leases	71	45
Redeemable long-term obligations		
Long-term debt	487	487
Capital leases	299	300
Subtotal	5,988	9,468
Reclassified to long-term debt	(4,285)	(4,110)
Total short-term debt	\$ 1,703	\$ 5,358

*Weighted-average interest rates at December 31, 2003 and 2002, were 1.01 percent and 1.47 percent, respectively, including the effect of interest rate swaps.



NOTE 17. SHORT-TERM DEBT – Continued

Redeemable long-term obligations consist primarily of tax-exempt variable-rate put bonds that are included as current liabilities because they become redeemable at the option of the bondholders during the year following the balance sheet date.

The company periodically enters into interest rate swaps on a portion of its short-term debt. See Note 8 beginning on page 57 for information concerning the company's debt-related derivative activities.

At December 31, 2003, the company had \$4,285 of committed credit facilities with banks worldwide, which permit the company to refinance short-term obligations on a long-term basis. The facilities support the company's commercial paper borrowings. Interest on borrowings under the terms of specific agreements may be based on the London Interbank Offered Rate or bank prime rate. No amounts were outstanding under these credit agreements during 2003 or at year-end.

At December 31, 2003 and 2002, the company classified \$4,285 and \$ 4,110, respectively, of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital in 2004, as the company has both the intent and the ability to refinance this debt on a long-term basis.

NOTE 18.

LONG-TERM DEBT

ChevronTexaco has three "shelf" registrations on file with the Securities and Exchange Commission that together would permit the issuance of \$3,800 of debt securities pursuant to Rule 415 of the Securities Act of 1933. The company's long-term debt outstanding at year-end 2003 and 2002 was as follows:

	At December 31	
	2003	2002
3.5% guarantees due 2007	\$ 1,993	\$ 1,992
3.375% notes due 2008	749	–
6.625% notes due 2004	499	499
5.5% note due 2009	431	439
7.327% amortizing notes due 2014 ¹	360	410
8.11% amortizing notes due 2004 ²	240	350
6% notes due 2005	299	299
9.75% debentures due 2020	250	250
5.7% notes due 2008	220	224
8.5% notes due 2003	–	200
7.75% debentures due 2033	–	199
8.625% debentures due 2031	199	199
8.625% debentures due 2032	199	199
7.5% debentures due 2043	198	198
6.875% debentures due 2023	–	196
7.09% notes due 2007	150	150
8.25% debentures due 2006	150	150
8.625% debentures due 2010	150	150
8.875% debentures due 2021	150	150
Medium-term notes, maturing from 2003 to 2043 (7.1%) ³	210	277
Other foreign currency obligations (4.4%) ³	52	87
Other long-term debt (3.5%) ³	730	678
Total including debt due within one year	7,229	7,296
Debt due within one year	(863)	(740)
Reclassified from short-term debt	4,285	4,110
Total long-term debt	\$ 10,651	\$ 10,666

¹ Guarantee of ESOP debt.

² Debt assumed from ESOP in 1999.

³ Less than \$150 individually; weighted-average interest rates at December 31, 2003.

Consolidated long-term debt maturing after December 31, 2003, is as follows: 2004 – \$863; 2005 – \$572; 2006 – \$326; 2007 – \$2,209; and 2008 – \$1,044; after 2008 – \$2,215.

In February 2003, the company redeemed \$200 of Texaco Capital Inc. bonds originally due in 2033. Also in February, the company issued \$750 of 3.375 percent bonds due in February 2008 under a shelf registration. The proceeds from this issuance were used to pay down commercial paper borrowings.

NOTE 19.

NEW ACCOUNTING STANDARDS

In January 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46). FIN 46 amended ARB 51, "Consolidated Financial Statements," and established standards for determining under what circumstances a variable interest entity (VIE) should be consolidated by its primary beneficiary. FIN 46 also requires disclosures about VIEs that the company is not required to consolidate but in which it has a significant variable interest. On December 17, 2003, the FASB issued FIN 46-R, which not only included amendments to FIN 46, but also required application of the interpretation to all affected entities no later than March 31, 2004, for calendar-year reporting companies. However, companies must have applied the interpretation to special-purpose entities by December 31, 2003. The adoption of FIN 46-R as it relates to special-purpose entities did not have a material impact on the company's results of operations, financial position or liquidity, and the company does not expect a material impact upon its full adoption of the interpretation as of March 31, 2004.

NOTE 20.

ACCOUNTING FOR MINERAL INTERESTS INVESTMENT

The Securities and Exchange Commission (SEC) has questioned certain public companies in the oil, gas and mining industries as to the proper accounting for and reporting of acquired contractual mineral interests under FASB Statement No. 141, "Business Combinations" (FAS 141), and FASB Statement No. 142, "Goodwill and Intangible Assets" (FAS 142). These accounting standards became effective for the company on July 1, 2001, and January 1, 2002, respectively.

At issue is whether such mineral interest costs should be classified on the balance sheet as part of "Properties, plant and equipment" or as "Intangible assets." The company will continue to classify these costs as "Properties, plant and equipment" and apportion them to expense in future periods under the company's existing accounting policy until authoritative guidance is provided.

For ChevronTexaco, the net book values of this category of mineral interest investment at December 31, 2003 and 2002, were \$3.8 billion and \$4.1 billion, respectively. If reclassification of these balances becomes necessary, the company's statements of income and cash flows would not be affected. However, additional disclosures related to intangible assets would be required as prescribed under the associated accounting standards.

NOTE 21.

EMPLOYEE BENEFIT PLANS

The company has defined benefit pension plans for many employees and provides for certain health care and life insurance plans for some active and qualifying retired employees. The company typically funds only those defined benefit plans where legal funding is required. In the United States, this includes all qualified tax-exempt plans subject to the Employee Retirement Income Security Act (ERISA) minimum funding standard. The company does not

typically fund domestic nonqualified tax-exempt pension plans or international pension plans that are not subject to legal funding requirements because contributions to these pension plans may be less tax efficient and investment returns may be less attractive than the company's other investment alternatives.

The company's annual contributions for medical and dental benefits are limited to the lesser of actual medical and dental claims or a defined fixed per-capita amount. Life insurance benefits are paid by the company and annual contributions are based on actual plan experience.

The company uses a measurement date of December 31 to value its pension and other postretirement benefit plan obligations.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) became law.

The Act introduces a prescription drug benefit under Medicare (Medicare Part D) as well as a federal subsidy to sponsors of retiree health care benefit plans, such as the company, that provide a benefit that is at least actuarially equivalent to Medicare Part D. The company is currently evaluating the impact of the legislation on its benefit plan design and accounting. The company has elected, in accordance with FASB Staff Position No. FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," to defer recognition of the Act in the company's measurement of the accumulated postretirement benefit obligation and net postretirement benefit cost in its financial statements and the accompanying notes. Specific accounting guidance for the federal subsidy is pending and, when issued, could require the company to change previously reported information.

The status of the company's pension and other postretirement benefit plans for 2003 and 2002 is as follows:

	Pension Benefits					
	2003		2002		Other Benefits	
	U.S.	Int'l.	U.S.	Int'l.	2003	2002
CHANGE IN BENEFIT OBLIGATION						
Benefit obligation at January 1	\$ 5,308	\$ 2,163	\$ 5,180	\$ 1,848	\$ 2,865	\$ 2,526
Service cost	144	54	112	47	28	25
Interest cost	334	151	334	143	191	178
Plan participants' contributions	1	1	2	3	–	–
Plan amendments	–	25	298	9	–	–
Actuarial loss	708	223	410	36	254	307
Foreign currency exchange rate changes	–	257	–	154	7	5
Benefits paid	(676)	(162)	(1,028)	(123)	(200)	(176)
Curtailment	–	(4)	–	–	–	–
Acquisitions/joint ventures	–	–	–	46	–	–
Benefit obligation at December 31	5,819	2,708	5,308	2,163	3,145	2,865
CHANGE IN PLAN ASSETS						
Fair value of plan assets at January 1	3,190	1,645	4,400	1,547	–	–
Actual return on plan assets	726	203	(284)	(139)	–	–
Foreign currency exchange rate changes	–	228	–	179	–	–
Employer contributions ¹	1,203	214	100	146	200	176
Plan participants' contributions	1	1	2	1	–	–
Benefits paid ¹	(676)	(162)	(1,028)	(123)	(200)	(176)
Acquisitions/joint ventures	–	–	–	34	–	–
Fair value of plan assets at December 31	4,444	2,129	3,190	1,645	–	–
FUNDED STATUS	(1,375)	(579)	(2,118)	(518)	(3,145)	(2,865)
Unrecognized net actuarial loss	1,598	918	1,686	793	656	414
Unrecognized prior-service cost	350	92	363	74	(19)	(21)
Unrecognized net transitional assets	–	8	–	(1)	–	–
Total recognized at December 31	\$ 573	\$ 439	\$ (69)	\$ 348	\$ (2,508)	(2,472)
AMOUNTS RECOGNIZED IN THE CONSOLIDATED						
BALANCE SHEET AT DECEMBER 31						
Prepaid benefit cost	\$ 10	\$ 679	\$ 164	\$ 652	\$ –	\$ –
Accrued benefit liability	(970)	(392)	(1,928)	(324)	(2,508)	(2,472)
Intangible asset	349	18	360	8	–	–
Accumulated other comprehensive income ²	1,184	134	1,335	12	–	–
Net amount recognized ³	\$ 573	\$ 439	\$ (69)	\$ 348	\$ (2,508)	(2,472)
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE						
BENEFIT OBLIGATIONS AS OF DECEMBER 31						
Discount rate	6.0%	6.8%	6.8%	7.1%	6.1%	6.8%
Rate of compensation increase	4.0%	4.9%	4.0%	5.1%	4.1%	4.1%

¹ Amounts for 2002 conformed to 2003 presentation to include company contributions and benefits paid for nonqualified plans.

² "Accumulated other comprehensive income" includes deferred income taxes of \$415 and \$47 in 2003 for U.S. and International, respectively, and \$467 and \$4 in 2002 for U.S. and International, respectively. This item is presented net of these taxes in the Consolidated Statement of Stockholders' Equity.

³ The company recorded additional minimum pension liabilities of \$1,533 and \$152 in 2003 for U.S. and International, respectively, and \$1,695 and \$20 in 2002 for U.S. and International, respectively, to reflect the amount of unfunded accumulated benefit obligations. The additional minimum pension liabilities are offset by intangible assets and a charge to "Accumulated other comprehensive income." Accrued liabilities also reflect net minimum liabilities for plans with prepaid benefit costs and additional minimum liabilities.



NOTE 21. EMPLOYEE BENEFIT PLANS – Continued

The accumulated benefit obligations for all U.S. pension plans and pension plans outside the U.S. were \$5,374 and \$2,372, respectively, at December 31, 2003, and \$4,945 and \$1,740, respectively, at December 31, 2002.

The components of net periodic benefit cost for 2003, 2002 and 2001 were:

	Pension Benefits						Other Benefits		
	2003		2002		2001		2003	2002	2001
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.			
Service cost	\$ 144	\$ 54	\$ 112	\$ 47	\$ 111	\$ 47	\$ 28	\$ 25	\$ 21
Interest cost	334	151	334	143	355	136	191	178	165
Expected return on plan assets	(224)	(132)	(288)	(138)	(443)	(170)	–	–	–
Amortization of transitional assets	–	(3)	–	(3)	(2)	(4)	–	–	–
Amortization of prior-service costs	45	14	32	12	25	12	(3)	(3)	(1)
Recognized actuarial losses (gains)	133	42	32	27	13	7	12	(1)	(6)
Settlement losses	132	1	146	1	12	–	–	–	–
Curtailement losses	–	6	–	–	26	–	–	–	20
Special termination benefit recognition	–	–	–	–	47	14	–	–	29
Net periodic benefit cost	\$ 564	\$ 133	\$ 368	\$ 89	\$ 144	\$ 42	\$ 228	\$ 199	\$ 228
Weighted-average assumptions used to determine net cost as of December 31									
Discount rate*	6.3%	7.1%	7.4%	7.7%	7.5%	7.8%	6.8%	7.3%	7.6%
Expected return on plan assets*	7.8%	8.3%	8.3%	8.9%	9.6%	9.1%	N/A	N/A	N/A
Rate of compensation increase	4.0%	5.1%	4.0%	5.4%	4.1%	5.0%	4.1%	4.1%	4.4%

* Discount rate and expected rate of return on plan assets were updated quarterly for the main U.S. pension plan.

The company employs a rigorous process to determine the estimates of long-term rate of return on pension assets. These estimates are primarily driven by actual historical asset-class returns and advice from external actuarial firms while incorporating specific asset-class risk factors. Asset allocations are regularly updated using pension plan asset/liability studies, and the determination of the company's estimates of long-term rates of return are consistent with these studies.

At December 31, 2003, the estimated long-term rate of return on U.S. pension plan assets, which account for about 70 percent of the company's pension plan assets, was 7.8 percent, compared with rates of 7.8 and 9.0 percent at the end of 2002 and 2001, respectively. The year-end market-related value of U.S. pension plan assets used in the determination of pension expense was based on the market values in the preceding three months, as opposed to the maximum allowable period of five years under U.S. accounting rules. Management considers the three-month time period long enough to minimize the effects of distortions from day-to-day market volatility and yet still be contemporaneous to the end of the year.

The asset allocation for the company's primary U.S. pension plans at the end of 2003 and 2002 and the target allocation, by asset category, are:

Asset Category	Board-Approved Asset Allocation	Policy Benchmark Asset Allocation	Actual Percentage of Plan Assets at Year-End	
			2003	2002
Equities	40–70%	60%	70%	63%
Fixed Income	20–60%	30%	21%	26%
Real Estate	0–15%	10%	8%	10%
Other	0– 5%	N/A	1%	1%
Total	N/A	100%	100%	100%

The U.S. pension plans invest primarily in asset categories with sufficient size, liquidity and cost efficiency to permit investments of reasonable size. The U.S. pension plans invest in asset categories that provide diversification benefits and are easily measured. Maximum and minimum holding ranges for each of these asset categories are set by the ChevronTexaco Board of Directors for the primary U.S. pension plan. Actual asset allocation within these approved ranges is based on a variety of economic and market conditions and consideration of specific asset category risk. To assess the plan's investment performance, a long-term asset allocation policy benchmark has been established.

Equities include investments in the company's common stock in the amount of \$6 and \$4 at December 31, 2003 and 2002, respectively. The "Other" asset category includes minimal investments in private equity limited partnerships.

In early 2004, the company contributed about \$535 to the U.S. plans. Additionally, the company anticipates contributing

Information for pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2003 and 2002 was:

	At December 31	
	2003	2002
Projected benefit obligations	\$ 6,637	\$ 5,761
Accumulated benefit obligations	6,067	5,327
Fair value of plan assets	4,791	3,283

about \$50 to the U.S. plans during the remainder of the year. In 2003, contributions to the U.S. plans totaled \$1,203. In years subsequent to 2004, the company expects contributions to be approximately \$250 per year, about equal to the cost of benefits earned in that year. Contributions in 2004 to the international pension plans are estimated at \$200, while 2003 contributions were \$214. The actual contribution amounts are dependent upon investment returns, changes in pension obligations, regulatory environments and other economic factors.

The company anticipates funding U.S. other postretirement benefits of \$210 in 2004, compared with \$197 in 2003.

For postretirement benefit measurement purposes in 2003, health care costs were assumed to increase approximately 8.4 percent over the previous year, and the trend rates gradually drop to 4.5 percent for 2007 and beyond.

	Assumed health care trend rates at December 31	
	2003	2002
U.S. health care cost-trend rate	8.4%	12.0%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.5%	4.5%
Year that the rate reaches the ultimate rate	2007	2007

Assumed health care cost-trend rates have a significant effect on the amounts reported for retiree health care costs. A one-percentage-point change in the assumed health care cost-trend rates would have the following effects:

	1 Percent Increase	1 Percent Decrease
Effect on total service and interest cost components	\$ 26	\$ (21)
Effect on postretirement benefit obligation	\$ 321	\$ (266)

Employee Savings Investment Plan Eligible employees of ChevronTexaco and certain of its subsidiaries participate in the ChevronTexaco Employee Savings Investment Plan (ESIP). In 2002, the Employees Thrift Plan of Texaco Inc., Employees Savings Plan of ChevronTexaco Global Energy Inc. (formerly Caltex Corporation), Stock Plan of ChevronTexaco Global Energy Inc. and Employees Thrift Plan of Fuel and Marine Marketing LLC were merged into the ChevronTexaco ESIP. Charges to expense for these plans were \$160, \$161 and \$157 in 2003, 2002 and 2001, respectively.

Employee Stock Ownership Plans (ESOP) Within the Chevron-Texaco Employee Savings Investment Plan, the company has established an employee stock ownership plan. In 1989, Chevron established a leveraged employee stock ownership plan (LESOP) as a constituent part of the ESOP. The LESOP provides partial prefunding of the company's future commitments to the ESIP, which will result in annual income tax savings for the company.

In 1988, Texaco established a leveraged employee stock ownership plan as a component of the Employees Thrift Plan of Texaco Inc. During 2002, the Employees Thrift Plan of Texaco Inc. was subsumed into the ChevronTexaco ESIP.

As permitted by American Institute of Certified Public Accountants (AICPA) Statement of Position 93-6, "Employers' Accounting for Employee Stock Ownership Plans," the company has elected to continue its practices, which are based on Statement of Position 76-3, "Accounting Practices for Certain

Employee Stock Ownership Plans," and subsequent consensus of the Emerging Issues Task Force of the Financial Accounting Standards Board. The debt of the LESOPs is recorded as debt, and shares pledged as collateral are reported as "Deferred compensation and benefit plan trust" in the Consolidated Balance Sheet and the Consolidated Statement of Stockholders' Equity.

The company reports compensation expense equal to LESOP debt principal repayments less dividends received by the LESOPs. Interest incurred on the LESOP debt is recorded as interest expense. Dividends paid on LESOP shares are reflected as a reduction of retained earnings. All LESOP shares are considered outstanding for earnings-per-share computations.

Expense recorded for the LESOPs was \$24, \$98 and \$75 in 2003, 2002 and 2001, respectively, including \$28, \$32 and \$43 of interest expense related to LESOP debt. All dividends paid on the LESOP shares held are used to service the LESOP debt. The dividends used were \$61, \$49 and \$86 in 2003, 2002 and 2001, respectively.

The company made LESOP contributions of \$26, \$102 and \$75 in 2003, 2002 and 2001, respectively, to satisfy LESOP debt service in excess of dividends received by the LESOP. The LESOP shares were pledged as collateral for the debt. Shares are released from a suspense account and allocated to the accounts of plan participants, based on the debt service deemed to be paid in the year in proportion to the total of current-year and remaining debt service. The (credit) charge to compensation expense was \$(4), \$66 and \$32 in 2003, 2002 and 2001, respectively. LESOP shares as of December 31, 2003 and 2002, were as follows:

Thousands	2003	2002
Allocated shares	12,099	12,513
Unallocated shares*	6,817	7,614
Total LESOP shares	18,916	20,127

* 2002 restated to conform to 2003 presentation.

Benefit Plan Trust Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2003, the trust contained 7.1 million shares of ChevronTexaco treasury stock. The company intends to continue to pay its obligations under the benefit plans. The trust will sell the shares or use the dividends from the shares to pay benefits only to the extent that the company does not pay such benefits. The trustee will vote the shares held in the trust as instructed by the trust's beneficiaries. The shares held in the trust are not considered outstanding for earnings-per-share purposes until distributed or sold by the trust in payment of benefit obligations.

Management Incentive Plans ChevronTexaco has two incentive plans, the Management Incentive Plan (MIP) and the Long-Term Incentive Plan (LTIP) for officers and other regular salaried employees of the company and its subsidiaries who hold positions of significant responsibility. The plans were expanded in 2002 to include former employees of Texaco and Caltex. The MIP is an annual cash incentive plan that links awards to performance results of the prior year. The cash awards may be deferred by conversion to stock units or other investment fund alternatives. Awards under the LTIP may take the form of, but are not limited to, stock options, restricted stock, stock units and nonstock grants. Texaco also had a cash incentive program and a Stock Incentive Plan (SIP) that included stock options, restricted stock and other incentive awards for executives, directors and key employees. Awards under the Caltex LTIP were in the form of performance units and stock appreciation rights. Charges to



NOTE 21. EMPLOYEE BENEFIT PLANS – Continued

expense for the combined management incentive plans, excluding expense related to LTIP and SIP stock options and restricted stock awards that are discussed in Note 22, below, were \$148, \$48 and \$101 in 2003, 2002 and 2001, respectively.

Other Incentive Plans The company has a program that provides eligible employees with an annual cash bonus if the company achieves certain financial and safety goals. Charges for the program were \$151, \$158 and \$154 in 2003, 2002 and 2001, respectively.

**NOTE 22.
STOCK OPTIONS**

The company applies APB Opinion No. 25 and related interpretations in accounting for its stock-based compensation programs, which are described below. Stock-based compensation expense (credit) recognized in connection with these programs was \$2, \$(2) and \$111 in 2003, 2002 and 2001, respectively.

Refer to Note 1 on page 54 for the pro forma effect on net income and earnings per share had the company applied the fair-value-recognition provisions of FAS No. 123.

Broad-Based Employee Stock Options In 1998, Chevron granted to all its eligible employees an option that varied from 100 to 300 shares of stock or equivalents, dependent on the employee's salary or job grade. These options vested after two years in February 2000. Options for 4,820,800 shares were awarded at an exercise price of \$76.3125 per share. Outstanding option shares were 2,366,311 at the end of 2001. In 2002, exercises of 295,985 and forfeitures of 61,151 reduced the outstanding option shares to 2,009,175 at the end of the year. In 2003, exercises of 11,630 and forfeitures of 61,050 reduced the outstanding option shares to 1,936,495 at the end of the year. The options expire in February 2008. The company recorded expense (credit) of \$2, \$(2) and \$1 for these options in 2003, 2002 and 2001, respectively.

The fair value of each option share on the date of grant under FAS No. 123 was estimated at \$19.08 using the average results of Black-Scholes models for the preceding 10 years. The 10-year averages of each assumption used by the Black-Scholes models were: a risk-free interest rate of 7.0 percent, a dividend yield of 4.2 percent, an expected life of seven years and a volatility of 24.7 percent.

Long-Term Incentive Plan Stock options granted under the LTIP extend for 10 years from the date of grant. Effective with options granted in June 2002, one-third of the options vest on each of the first, second and third anniversaries of the date of grant. Prior to this change, options granted by Chevron vested one year after the date of grant, whereas options granted by Texaco under its SIP vested over a two-year period at a rate of 50 percent each year. The maximum number of shares that may be granted each year is 1 percent of the total outstanding shares of common stock as of January 1 of such year.

On the closing of the merger in October 2001, outstanding options granted under the Texaco SIP were converted to ChevronTexaco options at the merger exchange rate of 0.77. These options retained a provision for restored options. This feature enables a participant who exercises a stock option by exchanging previously acquired common stock or who has shares withheld 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. Restricted shares granted under the former Texaco plan contained a performance element that had to be satisfied in order for all or a specified portion of the shares to vest. Upon the merger, all restricted shares became vested and converted to Chevron-Texaco shares at the merger exchange ratio of 0.77. Apart from the restored options, no further awards may be granted under the former Texaco plans. No amount for these plans was charged to compensation expense in 2003 or 2002; \$110 of expense was recorded in 2001. Restricted performance shares granted under SIP in 2001 totaled 392,000 at an average fair value of \$91.05 per share.

The fair market value of each stock option granted is estimated on the date of grant under FAS No. 123 using the Black-Scholes option-pricing model with the following weighted-average assumptions:

	2003	2002	2001
ChevronTexaco plans:			
Expected life in years	7	7	7
Risk-free interest rate	3.1%	4.6%	4.1%
Volatility	19.3%	21.6%	24.4%
Dividend yield	3.5%	3.0%	3.0%
Texaco plans:			
Expected life in years	2	2	2
Risk-free interest rate	1.7%	1.6%	3.9%
Volatility	22.0%	24.1%	25.9%
Dividend yield	3.9%	3.1%	3.1%

The Black-Scholes weighted-average fair value of the ChevronTexaco options granted during 2003, 2002 and 2001 was \$11.02, \$18.59 and \$20.45 per share, respectively, and the weighted-average fair value of the SIP restored options granted during 2003 and 2002 and the Texaco options granted during 2001 was \$8.06, \$10.29 and \$12.90 per share.

A summary of the status of stock options awarded under the company's LTIP, as well as the former Texaco plans, for 2003, 2002 and 2001 follows:

	Options (thousands)	Weighted-Average Exercise Price
Outstanding at December 31, 2000	20,870	\$ 75.67
Granted	3,777	89.84
Exercised	(8,209)	78.16
Restored	6,766	89.77
Forfeited	(584)	85.76
Outstanding at December 31, 2001	22,620	\$ 81.13
Granted	3,291	86.15
Exercised	(1,818)	73.01
Restored	1,274	89.38
Forfeited	(745)	88.10
Outstanding at December 31, 2002	24,622	\$ 82.66
Granted	4,660	73.39
Exercised	(729)	50.15
Restored	60	82.69
Forfeited	(983)	85.41
Outstanding at December 31, 2003	27,630	\$ 81.85
Exercisable at December 31		
2001	19,028	\$ 79.64
2002	21,445	\$ 82.14
2003	21,277	\$ 83.23

The following table summarizes information about stock options outstanding, including those from former Texaco plans, at December 31, 2003:

Range of Exercise Prices	Number Outstanding (thousands)	Options Outstanding		Options Exercisable	
		Weighted-Average Remaining Contractual Life (years)	Weighted-Average Exercise Price	Number Exercisable (thousands)	Weighted-Average Exercise Price
\$ 41 to \$ 51	1,217	1.1	\$ 46.02	1,217	\$ 46.02
51 to 61	23	2.8	56.24	23	56.24
61 to 71	683	2.8	66.26	683	66.26
71 to 81	8,554	7.1	76.15	4,114	79.11
81 to 91	13,305	6.1	86.82	11,392	86.93
91 to 101	3,848	5.8	91.61	3,848	91.61
\$ 41 to \$ 101	27,630	6.1	\$ 81.85	21,277	\$ 83.23

NOTE 23.

OTHER CONTINGENCIES AND COMMITMENTS

Income Taxes The company estimates its income tax expense and liabilities annually. These liabilities generally are not finalized with the individual taxing authorities until several years after the end of the annual period for which income taxes have been estimated. The U.S. federal income tax liabilities have been settled through 1996 for ChevronTexaco (formerly Chevron), 1993 for ChevronTexaco Global Energy Inc. (formerly Caltex), and 1991 for Texaco. California franchise tax liabilities have been settled through 1991 for Chevron and 1987 for Texaco. Settlement of open tax years, as well as tax issues in other countries where the company conducts its businesses, is not expected to have a material effect on the consolidated financial position or liquidity of the company, and in the opinion of management, adequate provision has been made for income and franchise taxes for all years under examination or subject to future examination.

Guarantees At December 31, 2003, the company and its subsidiaries provided guarantees, either directly or indirectly, of \$917 for notes and other contractual obligations of affiliated companies and \$256 for third parties, as discussed, by major category, below. There are no amounts being carried as liabilities for the company's obligations under these guarantees. Of the \$917 guarantees provided to affiliates, \$716 related to borrowings for capital projects or general corporate purposes. These guarantees were undertaken to achieve lower interest rates and generally cover the construction period of the capital projects. Approximately 75 percent of the amounts guaranteed will expire in 2004, with the remaining guarantees expiring by the end of 2015. Under the terms of the guarantees, the company would be required to fulfill the guarantee should an affiliate be in default of its loan terms, generally for the full amounts disclosed. There are no recourse provisions, and no assets are held as collateral for these guarantees.

Another \$201 of the affiliate guarantees related to obligations in connection with pricing of power purchase agreements for certain of the company's cogeneration affiliates. Under the terms of these guarantees, the company may be required to make payments under certain conditions if the affiliates do not perform under the agreements. There are no provisions for recourse to third parties, and no assets are held as collateral for these pricing guarantees.

Guarantees of \$256 have been provided to third parties, including approximately \$110 of construction loans to host governments in the company's international upstream operations. The other \$146 was provided principally as conditions of sale of the company's interest in certain operations, to provide a source of liquidity to the guaranteed parties and in connection with company marketing programs. No amounts of the company's obligations under these guarantees are recorded as liabilities. About 75 percent of the total amounts guaranteed will expire in 2004, with the remainder expiring after 2004. The company would be required to perform under the terms of the guarantees should an entity be in default of its loan or contract terms, generally for the full amounts disclosed. Approximately \$100 of the guarantees have recourse provisions, which enable the company to recover any payments made under the terms of the guarantees from securities held over the guaranteed parties' assets.

At December 31, 2003, ChevronTexaco had outstanding guarantees for approximately \$238 of Equilon debt and leases. Following the February 2002 disposition of its interest in Equilon, the company received an indemnification from Shell Oil Company for any claims arising from the guarantees. The company has not recorded a liability for these guarantees. Approximately 50 percent of the amounts guaranteed will expire within the 2004–2008 period, with the guarantees of the remaining amounts expiring by 2019.

Indemnities The company also provided certain indemnities of contingent liabilities of Equilon and Motiva to Shell Oil Company (Shell) and Saudi Refining Inc. in connection with the February 2002 sale of the company's interests in those investments. The indemnities cover general contingent liabilities, including those associated with the Unocal patent litigation. The company would be required to perform should the indemnified liabilities become actual losses and could be required to make maximum future payments of \$300. The company has paid approximately \$28 under these contingencies and has disputed approximately \$34 in claims submitted by Shell under these indemnities. Shell requested arbitration of this dispute, and it is expected to occur in mid-2004. There are no recourse provisions enabling recovery of any amounts from third parties nor are any assets held as collateral. Within five years of the February 2002 sale, at the buyer's option, the company also may be required to purchase certain assets from Shell for their net book value, as determined at the time of the company's purchase. Those assets consist of 12 separate lubricant facilities, two of which were tendered to and purchased by the company in late 2003 for a *de minimis* price.

The company has also provided certain indemnities pertaining to the contingent environmental liabilities related to assets originally contributed by Texaco to the Equilon and Motiva joint ventures and environmental conditions that existed prior to the formation of Equilon and Motiva or that occurred during the periods of ChevronTexaco's ownership interests in the joint ventures. In general, the environmental conditions and events that are subject to these indemnities must have arisen prior to December 2001. Claims relating to Equilon must be asserted no later than February 2009, and claims relating to Motiva must be asserted no later than February 2012. Under the terms of the indemnities, there is no maximum limit on the amount of potential future payments. The company has not recorded any liabilities for possible claims under these indemnities. The company holds no assets as collateral and has made no payments under the indemnities.



NOTE 23. OTHER CONTINGENCIES AND COMMITMENTS – Continued

The amounts payable for the indemnities described above are to be net of amounts recovered from insurance carriers and others and net of liabilities recorded by Equilon or Motiva prior to September 30, 2001, for any specific incident.

Securitization The company securitizes certain retail and trade accounts receivable in its downstream business through the use of qualifying special purpose entities (SPEs). At December 31, 2003, approximately \$1,000, representing about 11 percent of ChevronTexaco's total current accounts receivables balance, were securitized. ChevronTexaco's total estimated financial exposure under these arrangements at December 31, 2003, was approximately \$75. These arrangements have the effect of accelerating ChevronTexaco's collection of the securitized amounts. In the event of the SPEs experiencing major defaults in the collection of receivables, ChevronTexaco believes that it would have no loss exposure connected with third-party investments in these securitization arrangements.

Long-Term Unconditional Purchase Obligations and Commitments, Throughput Agreements, and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities relating to long-term unconditional purchase obligations and commitments, throughput agreements, and take-or-pay agreements, some of which relate to suppliers' financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate amounts of required payments under these various commitments are 2004 – \$1,200; 2005 – \$1,100; 2006 – \$1,000; 2007 – \$1,000; 2008 – \$1,000; 2009 and after – \$1,900. Total payments under the agreements were \$1,400 in 2003, \$1,200 in 2002 and \$1,500 in 2001. The most significant take-or-pay agreement calls for the company to purchase approximately 55,000 barrels per day of refined products from an equity affiliate refiner in Thailand. This purchase agreement is in conjunction with the financing of a refinery owned by the affiliate and expires in 2009. The future estimated commitments under this contract are: 2004 – \$700; 2005 – \$800; 2006 – \$800; 2007 – \$800; 2008 – \$800 and 2009 – \$800.

Minority Interests The company has commitments related to preferred shares of subsidiary companies, which are accounted for as minority interest. Texaco Capital LLC, a wholly owned finance subsidiary, has issued \$65 of Deferred Preferred Shares, Series C. Dividends amounting to \$60 on Series C, at a rate of 7.17 percent compounded annually, will be paid at the redemption date in February 2005, unless earlier redemption occurs. Early redemption may result upon the occurrence of certain specific events. MVP Production Inc., a subsidiary, redeemed variable rate cumulative preferred shares of \$75 owned by one minority holder during 2003.

Environmental The company is subject to loss contingencies pursuant to environmental laws and regulations that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemical or petroleum substances, including MTBE, by the

company or other parties. Such contingencies may exist for various sites, including but not limited to Superfund sites and refineries, oil fields, service stations, terminals, and land development areas, whether operating, closed or sold. The amount of such future cost is indeterminable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties. While the company has provided for known environmental obligations that are probable and reasonably estimable, the amount of additional future costs may be material to results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had, or will have, any significant impact on the company's competitive position relative to other U.S. or international petroleum or chemicals concerns.

Global Operations ChevronTexaco and its affiliates have operations in more than 180 countries. Areas in which the company and its affiliates have major operations include the United States, Canada, Australia, the United Kingdom, Norway, Denmark, France, Partitioned Neutral Zone between Kuwait and Saudi Arabia, Republic of Congo, Angola, Nigeria, Chad, Equatorial Guinea, Democratic Republic of Congo, South Africa, Indonesia, the Philippines, Singapore, China, Thailand, Venezuela, Argentina, Brazil, Colombia, Trinidad and Tobago, and South Korea. The company's Caspian Pipeline Consortium (CPC) affiliate operates in Russia and Kazakhstan. The company's Tengizchevroil affiliate operates in Kazakhstan. The company's Chevron Phillips Chemical Company LLC affiliate manufactures and markets a wide range of petrochemicals on a worldwide basis, with manufacturing facilities in the United States, Puerto Rico, Singapore, China, South Korea, Saudi Arabia, Qatar, Mexico and Belgium.

The company's operations, particularly exploration and production, can be affected by changing economic, regulatory and political environments in the various countries in which it operates, including the United States. As has occurred in the past, actions could be taken by host governments to increase public ownership of the company's partially or wholly owned businesses and/or to impose additional taxes or royalties on the company's operations.

In certain locations, host governments have imposed restrictions, controls and taxes, and in others, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries. Internal unrest or strained relations between a host government and the company or other governments may affect the company's operations. Those developments have, at times, significantly affected the company's related operations and results and are carefully considered by management when evaluating the level of current and future activity in such countries.

Equity Redetermination For oil and gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated oil and gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for ChevronTexaco's interests in four producing zones at the

Naval Petroleum Reserve at Elk Hills, California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range remains for a possible net settlement amount for the four zones. ChevronTexaco currently estimates its maximum possible net before-tax liability at approximately \$200. At the same time, a possible maximum net amount that could be owed to ChevronTexaco is estimated at about \$50. The timing of the settlement and the exact amount within this range of estimates is uncertain.

Other Contingencies ChevronTexaco receives claims from and submits claims to customers, trading partners, U.S. federal, state and local regulatory bodies, host governments, contractors, insurers, and suppliers. The amounts of these claims, individually and in the aggregate, may be significant and take lengthy periods to resolve.

The company and its affiliates also continue to review and analyze their operations and may close, abandon, sell, exchange,

acquire or restructure assets to achieve operational or strategic benefits and to improve competitiveness and profitability. These activities, individually or together, may result in gains or losses in future periods.

NOTE 24.**EARNINGS PER SHARE**

Basic earnings per share (EPS) is based upon net income less preferred stock dividend requirements and includes the effects of deferrals of salary and other compensation awards that are invested in ChevronTexaco stock units by certain officers and employees of the company and the company's share of stock transactions of affiliates, which, under the applicable accounting rules, may be recorded directly to the company's retained earnings instead of net income. Diluted EPS includes the effects of these items as well as the dilutive effects of outstanding stock options awarded under the company's stock option programs (see Note 22, "Stock Options" on pages 70 and 71). The following table sets forth the computation of basic and diluted EPS:

	2003			2002			2001		
	Net Income	Shares (millions)	Per-Share Amount	Net Income	Shares (millions)	Per-Share Amount	Net Income	Shares (millions)	Per-Share Amount
Basic EPS Calculation									
Net Income Before Extraordinary Items and Cumulative Effect of Changes in Accounting Principles									
	\$ 7,426			\$ 1,132			\$ 3,931		
Weighted-average common shares outstanding		1,061.6			1,060.7			1,059.3	
Dividend equivalents paid on ChevronTexaco stock units	2			3			2		
Deferred awards held as ChevronTexaco stock units		0.9			0.8			0.8	
Affiliate stock transactions recorded to retained earnings ¹	170			–			–		
Preferred stock dividends	–			–			(6)		
Net Income Before Extraordinary Items and Cumulative Effect of Changes in Accounting Principles – Basic									
	\$ 7,598	1,062.5	\$ 7.15	\$ 1,135	1,061.5	\$ 1.07	\$ 3,927	1,060.1	\$ 3.71
Extraordinary item ²	–			–			(643)		(0.61)
Cumulative effect of changes in accounting principles ³	(196)		(0.18)	–			–		
Net Income – Basic	\$ 7,402	1,062.5	\$ 6.97	\$ 1,135	1,061.5	\$ 1.07	\$ 3,284	1,060.1	\$ 3.10
Diluted EPS Calculation									
Net Income Before Extraordinary Items and Cumulative Effect of Changes in Accounting Principles – Basic									
	\$ 7,598	1,062.5		\$ 1,135	1,061.5		\$ 3,927	1,060.1	
Dilutive effects of stock options, restricted stock and convertible debentures	2	1.5		2	1.9		4	2.8	
Net Income Before Extraordinary Items and Cumulative Effect of Changes in Accounting Principles – Diluted									
	\$ 7,600	1,064.0	\$ 7.14	\$ 1,137	1,063.4	\$ 1.07	3,931	1,062.9	\$ 3.70
Extraordinary item ²	–			–			(643)		(0.61)
Cumulative effect of changes in accounting principles ³	(196)		(0.18)	–			–		
Net Income – Diluted	\$ 7,404	1,064.0	\$ 6.96	\$ 1,137	1,063.4	\$ 1.07	\$ 3,288	1,062.9	\$ 3.09

¹ 2003 amount is the company's share of a capital stock transaction of its Dynege affiliate, which, under the applicable accounting rules, was recorded directly to retained earnings.

² See Note 2 on page 54 for explanation of extraordinary item.

³ Includes a net loss of \$200 for the adoption of FAS 143 and a gain of \$4 for the company's share of Dynege's cumulative effect of adoption of EITF No. 02-3.



NOTE 25.

FAS 143 – ASSET RETIREMENT OBLIGATIONS

The company adopted Financial Accounting Standards Board Statement No. 143, “Accounting for Asset Retirement Obligations” (FAS 143), effective January 1, 2003. This accounting standard applies to the fair value of a liability for an asset retirement obligation that is recorded when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. Obligations associated with the retirement of these assets require recognition in certain circumstances: (1) the present value of a liability and offsetting asset for an asset retirement obligation (ARO), (2) the subsequent accretion of that liability and depreciation of the asset, and (3) the periodic review of the ARO liability estimates and discount rates. FAS 143 primarily affects the company’s accounting for oil and gas producing assets and differs in several respects from previous accounting under FAS 19, “Financial Accounting and Reporting by Oil and Gas Producing Companies.”

In the first quarter 2003, the company recorded a net after-tax charge of \$200 for the cumulative effect of the adoption of FAS 143, including the company’s share of amounts attributable to equity affiliates. The cumulative-effect adjustment also increased the following balance sheet categories: “Properties, plant and equipment,” \$2,568; “Accrued liabilities,” \$115; and “Deferred credits and other noncurrent obligations,” \$2,674. “Noncurrent deferred income taxes” decreased by \$21.

Upon adoption, no significant legal obligations to retire refining, marketing and transportation (downstream) and chemical long-lived assets generally were recognized, as indeterminate settlement dates for the asset retirements prevented estimation of the fair value of the associated ARO. The company performs periodic reviews of its downstream and chemical long-lived assets for any changes in facts and circumstances that might require recognition of a retirement obligation.

Other than the cumulative-effect net charge, the effect of the new accounting standard on net income in 2003 was not materially different from what the result would have been under FAS 19 accounting. Included in “Depreciation, depletion and amortization” were \$52 related to the depreciation of the ARO asset and \$132 related to the accretion of the ARO liability.

The following table illustrates what the company’s net income before extraordinary items, net income and related per-share amounts would have been if the provisions of FAS 143 had been applied retroactively:

	Year Ended December 31		
	2003	2002	2001
Proforma net income before extraordinary items	\$ 7,430 ¹	\$ 1,137 ²	\$ 3,933 ²
Earnings per share – basic ³	\$ 7.15	\$ 1.07	\$ 3.71
Earnings per share – diluted ³	\$ 7.14	\$ 1.07	\$ 3.70
Proforma net income	\$ 7,430 ¹	\$ 1,137 ²	\$ 3,290 ²
Earnings per share – basic ⁴	\$ 7.15	\$ 1.07	\$ 3.10
Earnings per share – diluted ⁴	\$ 7.14	\$ 1.07	\$ 3.09

¹ Amount excludes cumulative-effect charge of \$200 (\$0.18 per basic and diluted share) for the adoption of FAS 143.

² Includes benefit of \$5 and \$2 for 2002 and 2001, respectively, which represents the reversal of FAS 19 depreciation related to abandonment offset partially by proforma expenses for the depreciation and accretion of the ARO asset and liability, net of tax. There is a *de minimis* effect to net income per basic or diluted share.

³ Reported net income before extraordinary items was \$1.07 per basic and diluted share for 2002 and \$3.71 per basic share (\$3.70 – diluted) for 2001.

⁴ Reported net income was \$1.07 per basic and diluted share for 2002 and \$3.10 per basic share (\$3.09 – diluted) for 2001.

Prior to the implementation of FAS 143, the company had recorded a provision for abandonment that was part of “Accumulated depreciation, depletion and amortization.” Upon implementation of FAS 143, the provision for abandonment was reversed and ARO liability was recorded. The amount of the abandonment reserve at the end of each year and the proforma ARO liability were as follows:

	2003	2002	2001
ARO liability (FAS 143) at January 1	\$ 2,797	\$ 2,792	\$ 2,729
ARO liability (FAS 143) at December 31	2,856	2,797	2,792
Abandonment provision (FAS 19) at December 31	–	2,263	2,155

The following table indicates the changes to the company’s before-tax asset retirement obligations in 2003:

	2003
Balance at Jan. 1 – Cumulative effect of the accounting change	\$ 2,797
Liabilities incurred	14
Liabilities settled	(128)
Accretion expense	132
Revisions in estimated cash flows	41
Balance at December 31	\$ 2,856

Millions of dollars, except per-share amount	2003				2002			
	4TH Q	3RD Q	2ND Q	1ST Q	4TH Q	3RD Q	2ND Q	1ST Q
REVENUES AND OTHER INCOME								
Sales and other operating revenues ¹	\$ 30,132	\$ 30,163	\$ 29,085	\$ 30,652	\$ 26,943	\$ 25,681	\$ 25,223	\$ 20,844
Income (loss) from equity affiliates	262	287	215	265	111	(329)	81	112
Gain from exchange of Dynegy securities	—	365	—	—	—	—	—	—
Other income	71	155	61	48	4	15	29	199
TOTAL REVENUES AND OTHER INCOME	30,465	30,970	29,361	30,965	27,058	25,367	25,333	21,155
COSTS AND OTHER DEDUCTIONS								
Purchased crude oil and products	17,964	18,007	17,337	18,275	15,871	14,871	14,694	11,813
Operating expenses	2,512	2,321	1,782	1,938	2,279	2,118	1,699	1,752
Selling, general and administrative expenses	1,173	1,197	1,061	1,009	1,107	1,032	1,153	863
Exploration expenses	139	130	147	155	205	166	135	85
Depreciation, depletion and amortization	1,322	1,409	1,411	1,242	1,271	1,514	1,241	1,205
Write-down of investments in Dynegy Inc.	—	—	—	—	—	1,094	702	—
Merger-related expenses	—	—	—	—	163	111	119	183
Taxes other than on income ¹	4,645	4,418	4,513	4,330	4,403	4,369	4,137	3,780
Interest and debt expense	111	115	118	130	141	117	160	147
Minority interests	14	24	20	22	22	13	10	12
TOTAL COSTS AND OTHER DEDUCTIONS	27,880	27,621	26,389	27,101	25,462	25,405	24,050	19,840
INCOME BEFORE INCOME TAX EXPENSE	2,585	3,349	2,972	3,864	1,596	(38)	1,283	1,315
INCOME TAX EXPENSE	850	1,374	1,372	1,748	692	866	876	590
NET INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	\$ 1,735	\$ 1,975	\$ 1,600	\$ 2,116	\$ 904	\$ (904)	\$ 407	\$ 725
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES, NET OF TAX	—	—	—	(196)	—	—	—	—
NET INCOME (LOSS)²	\$ 1,735	\$ 1,975	\$ 1,600	\$ 1,920	\$ 904	\$ (904)	\$ 407	\$ 725
NET INCOME (LOSS) PER SHARE BEFORE CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES								
— BASIC	\$ 1.63	\$ 2.02 ³	\$ 1.51	\$ 1.99	\$ 0.85	\$ (0.85)	\$ 0.39	\$ 0.68
— DILUTED	\$ 1.63	\$ 2.02 ³	\$ 1.50	\$ 1.99	\$ 0.85	\$ (0.85)	\$ 0.39	\$ 0.68
NET INCOME (LOSS) PER SHARE								
— BASIC	\$ 1.63	\$ 2.02 ³	\$ 1.51	\$ 1.81	\$ 0.85	\$ (0.85)	\$ 0.39	\$ 0.68
— DILUTED	\$ 1.63	\$ 2.02 ³	\$ 1.50	\$ 1.81	\$ 0.85	\$ (0.85)	\$ 0.39	\$ 0.68
DIVIDENDS PAID PER SHARE	\$ 0.73	\$ 0.73	\$ 0.70					
COMMON STOCK PRICE RANGE – HIGH	\$ 86.99	\$ 74.56	\$ 76.23	\$ 70.40	\$ 75.43	\$ 88.93	\$ 91.04	\$ 91.60
— LOW	\$ 71.14	\$ 70.05	\$ 62.13	\$ 61.31	\$ 65.41	\$ 65.64	\$ 83.55	\$ 80.80
¹ Includes consumer excise taxes:	\$ 1,825	\$ 1,814	\$ 1,765	\$ 1,691	\$ 1,785	\$ 1,782	\$ 1,751	\$ 1,688
² Net benefits (charges) for special items included in "Net Income (Loss)":	\$ 89	\$ 14	\$ (117)	\$ (39)	\$ (161)	\$ (2,141)	\$ (826)	\$ (206)
³ Includes a benefit of \$0.16 for the company's share of a capital stock transaction of its Dynegy Inc. affiliate, which, under the applicable accounting rules, was recorded directly to retained earnings and not included in the net income for the period.								

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX) and on the Pacific Exchange. As of February 25, 2004, stockholders of record numbered approximately 239,000. Through October 9, 2001, the common stock traded under the name of Chevron Corporation (trading symbol: CHV).

There are no restrictions on the company's ability to pay dividends.

» Five-Year Financial Summary

Millions of dollars, except per-share amounts	2003	2002	2001	2000	1999
COMBINED STATEMENT OF INCOME DATA					
REVENUES AND OTHER INCOME					
Total sales and other operating revenues	\$ 120,032	\$ 98,691	\$ 104,409	\$ 117,095	\$ 84,004
Income from equity affiliates and other income	1,729	222	1,836	2,035	1,709
TOTAL REVENUES AND OTHER INCOME	121,761	98,913	106,245	119,130	85,713
TOTAL COSTS AND OTHER DEDUCTIONS					
	108,991	94,757	97,954	105,081	79,901
INCOME BEFORE INCOME TAXES	12,770	4,156	8,291	14,049	5,812
INCOME TAX EXPENSE	5,344	3,024	4,360	6,322	2,565
NET INCOME BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES					
	7,426	1,132	3,931	7,727	3,247
Extraordinary loss, net of tax	–	–	(643)	–	–
Cumulative effect of changes in accounting principles	(196)	–	–	–	–
NET INCOME	\$ 7,230	\$ 1,132	\$ 3,288	\$ 7,727	\$ 3,247
PER-SHARE AMOUNTS					
BASIC:					
NET INCOME BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES¹					
	\$ 7.15	\$ 1.07	\$ 3.71	\$ 7.23	\$ 3.01
Extraordinary item	\$ –	\$ –	\$ (0.61)	\$ –	\$ –
Cumulative effect of changes in accounting principles	\$ (0.18)	\$ –	\$ –	\$ –	\$ –
NET INCOME¹	\$ 6.97	\$ 1.07	\$ 3.10	\$ 7.23	\$ 3.01
DILUTED:					
NET INCOME BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES¹					
	\$ 7.14	\$ 1.07	\$ 3.70	\$ 7.21	\$ 3.00
Extraordinary item	\$ –	\$ –	\$ (0.61)	\$ –	\$ –
Cumulative effect of changes in accounting principles	\$ (0.18)	\$ –	\$ –	\$ –	\$ –
NET INCOME¹	\$ 6.96	\$ 1.07	\$ 3.09	\$ 7.21	\$ 3.00
CASH DIVIDENDS PER SHARE²	\$ 2.86	\$ 2.80	\$ 2.65	\$ 2.60	\$ 2.48
COMBINED BALANCE SHEET DATA (AT DECEMBER 31)					
Current assets	\$ 19,426	\$ 17,776	\$ 18,327	\$ 17,913	\$ 17,043
Noncurrent assets	62,044	59,583	59,245	59,708	58,337
TOTAL ASSETS	81,470	77,359	77,572	77,621	75,380
Short-term debt	1,703	5,358	8,429	3,094	6,063
Other current liabilities	14,408	14,518	12,225	13,567	11,620
Long-term debt and capital lease obligations	10,894	10,911	8,989	12,821	13,145
Other noncurrent liabilities	18,170	14,968	13,971	14,770	14,761
TOTAL LIABILITIES	45,175	45,755	43,614	44,252	45,589
STOCKHOLDERS' EQUITY	\$ 36,295	\$ 31,604	\$ 33,958	\$ 33,369	\$ 29,791

¹ The amount in 2003 includes a benefit of \$0.16 for the company's share of a capital stock transaction of its Dynegy Inc. affiliate, which, under the applicable accounting rules, was recorded directly to retained earnings and not included in net income for the period.

² Chevron Corporation dividend pre-merger.

» Supplemental Information on Oil and Gas Producing Activities

Unaudited

In accordance with Statement of Financial Accounting Standards No. 69, "Disclosures About Oil and Gas Producing Activities" (FAS 69), this section provides supplemental information on oil and gas exploration and producing activities of the company in seven separate tables. Tables I through IV provide historical cost information pertaining to costs incurred in exploration, property acquisitions and development; capitalized costs; and results of operations. Tables V through VII present information on the

company's estimated net proved reserve quantities; standardized measure of estimated discounted future net cash flows related to proved reserves; and changes in estimated discounted future net cash flows. The Africa geographic area includes activities principally in Nigeria, Angola, Chad, Republic of Congo and Democratic Republic of Congo. The Asia-Pacific geographic area includes activities principally in Australia, China, Indonesia, Kazakhstan, Partitioned Neutral Zone between Kuwait and Saudi

Arabia, Papua New Guinea, the Philippines, and Thailand. The “Other” geographic category includes activities in the United Kingdom, Canada, Denmark, the Netherlands, Norway, Trinidad and Tobago, Colombia, Venezuela, Brazil, Argentina, and other countries. Amounts shown for affiliated companies are ChevronTexaco’s 50 percent equity share

of Tengizchevroil (TCO), an exploration and production partnership operating in the Republic of Kazakhstan, and a 30 percent equity share of Hamaca, an exploration and production partnership operating in Venezuela. The company increased its ownership in TCO from 45 percent to 50 percent in January 2001.

Amounts in the tables exclude the cumulative effect adjustment for the adoption of FAS 143, “Asset Retirement Obligations.” Refer to Note 25 on page 74.

TABLE I – COSTS INCURRED IN EXPLORATION, PROPERTY ACQUISITIONS AND DEVELOPMENT¹

Millions of dollars	Consolidated Companies					Affiliated Companies		Worldwide
	U.S.	Africa	Asia-Pacific	Other	Total	TCO ²	Hamaca	
YEAR ENDED DECEMBER 31, 2003								
Exploration								
Wells	\$ 424	\$ 116	\$ 45	\$ 72	\$ 657	\$ –	\$ –	\$ 657
Geological and geophysical	39	75	14	30	158	–	–	158
Rentals and other	44	12	58	46	160	–	–	160
Total exploration	507	203	117	148	975	–	–	975
Property acquisitions								
Proved ³	18	–	20	7	45	–	–	45
Unproved	33	51	6	14	104	–	–	104
Total property acquisitions	51	51	26	21	149	–	–	149
Development	1,048	974	968	461	3,451	551	199	4,201
TOTAL COSTS INCURRED	\$ 1,606	\$ 1,228	\$ 1,111	\$ 630	\$ 4,575	\$ 551	\$ 199	\$ 5,325
YEAR ENDED DECEMBER 31, 2002								
Exploration								
Wells	\$ 477	\$ 131	\$ 48	\$ 92	\$ 748	\$ –	\$ –	\$ 748
Geological and geophysical	95	69	43	53	260	–	–	260
Rentals and other	35	29	38	43	145	–	–	145
Total exploration	607	229	129	188	1,153	–	–	1,153
Property acquisitions								
Proved ³	106	–	–	–	106	–	–	106
Unproved	51	6	2	1	60	–	–	60
Total property acquisitions	157	6	2	1	166	–	–	166
Development	1,091	661	1,017	926	3,695	447	353	4,495
TOTAL COSTS INCURRED	\$ 1,855	\$ 896	\$ 1,148	\$ 1,115	\$ 5,014	\$ 447	\$ 353	\$ 5,814
YEAR ENDED DECEMBER 31, 2001								
Exploration								
Wells	\$ 620	\$ 172	\$ 186	\$ 197	\$ 1,175	\$ –	\$ –	\$ 1,175
Geological and geophysical	46	35	42	65	188	–	–	188
Rentals and other	65	48	15	98	226	–	–	226
Total exploration	731	255	243	360	1,589	–	–	1,589
Property acquisitions								
Proved ³	25	4	–	–	29	362	–	391
Unproved	50	38	12	–	100	108	–	208
Total property acquisitions	75	42	12	–	129	470	–	599
Development	1,754	551	1,168	494	3,967	266	275	4,508
TOTAL COSTS INCURRED	\$ 2,560	\$ 848	\$ 1,423	\$ 854	\$ 5,685	\$ 736	\$ 275	\$ 6,696

¹ Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. See Note 25, FAS 143 “Asset Retirement Obligations,” on page 74.

² Includes acquisition costs for an additional 5 percent interest in 2001.

³ Includes wells, equipment and facilities associated with proved reserves. Does not include properties acquired through property exchanges.



Unaudited

TABLE II – CAPITALIZED COSTS RELATED TO OIL AND GAS PRODUCING ACTIVITIES¹

Millions of dollars	Consolidated Companies					Affiliated Companies		Worldwide
	U.S.	Africa	Asia-Pacific	Other	Total	TCO	Hamaca	
AT DECEMBER 31, 2003								
Unproved properties	\$ 1,316	\$ 290	\$ 214	\$ 1,048	\$ 2,868	\$ 108	\$ –	\$ 2,976
Proved properties and related producing assets	37,603	6,474	10,391	10,469	64,937	2,091	356	67,384
Support equipment	677	519	2,110	374	3,680	425	–	4,105
Deferred exploratory wells	248	221	69	120	658	–	–	658
Other uncompleted projects	387	1,906	2,217	334	4,844	1,011	661	6,516
ARO asset ²	335	207	83	236	861	20	1	882
GROSS CAPITALIZED COSTS	40,566	9,617	15,084	12,581	77,848	3,655	1,018	82,521
Unproved properties valuation	912	101	60	310	1,383	12	–	1,395
Proved producing properties – depreciation and depletion	27,817	3,656	5,534	5,868	42,875	354	24	43,253
Support equipment depreciation	454	237	1,133	347	2,171	160	–	2,331
ARO asset depreciation ²	288	133	55	148	624	4	–	628
Accumulated provisions	29,471	4,127	6,782	6,673	47,053	530	24	47,607
NET CAPITALIZED COSTS	\$ 11,095	\$ 5,490	\$ 8,302	\$ 5,908	\$ 30,795	\$ 3,125	\$ 994	\$ 34,914
AT DECEMBER 31, 2002								
Unproved properties	\$ 1,362	\$ 330	\$ 259	\$ 1,134	\$ 3,085	\$ 108	\$ –	\$ 3,193
Proved properties and related producing assets	37,441	6,037	10,794	10,185	64,457	1,975	147	66,579
Support equipment	774	447	2,188	377	3,786	338	–	4,124
Deferred exploratory wells	106	130	103	111	450	–	–	450
Other uncompleted projects	502	1,417	1,653	259	3,831	676	693	5,200
GROSS CAPITALIZED COSTS	40,185	8,361	14,997	12,066	75,609	3,097	840	79,546
Unproved properties valuation	961	80	90	277	1,408	9	–	1,417
Proved producing properties – depreciation and depletion	27,115	3,275	5,470	5,358	41,218	285	9	41,512
Future abandonment and restoration	999	508	304	392	2,203	24	–	2,227
Support equipment depreciation	557	289	1,145	223	2,214	138	–	2,352
Accumulated provisions	29,632	4,152	7,009	6,250	47,043	456	9	47,508
NET CAPITALIZED COSTS	\$ 10,553	\$ 4,209	\$ 7,988	\$ 5,816	\$ 28,566	\$ 2,641	\$ 831	\$ 32,038
AT DECEMBER 31, 2001								
Unproved properties	\$ 1,178	\$ 304	\$ 565	\$ 1,168	\$ 3,215	\$ 108	\$ –	\$ 3,323
Proved properties and related producing assets	35,665	5,531	10,590	9,253	61,039	1,878	91	63,008
Support equipment	766	390	2,177	313	3,646	293	–	3,939
Deferred exploratory wells	91	390	128	79	688	–	–	688
Other uncompleted projects	1,080	753	686	292	2,811	245	381	3,437
GROSS CAPITALIZED COSTS	38,780	7,368	14,146	11,105	71,399	2,524	472	74,395
Unproved properties valuation	807	86	73	222	1,188	7	–	1,195
Proved producing properties – depreciation and depletion	25,844	3,020	4,802	4,736	38,402	212	3	38,617
Future abandonment and restoration	1,016	449	281	342	2,088	19	–	2,107
Support equipment depreciation	452	160	1,122	162	1,896	123	–	2,019
Accumulated provisions	28,119	3,715	6,278	5,462	43,574	361	3	43,938
NET CAPITALIZED COSTS	\$ 10,661	\$ 3,653	\$ 7,868	\$ 5,643	\$ 27,825	\$ 2,163	\$ 469	\$ 30,457

¹ Includes assets held for sale.

² See Note 25, FAS 143 “Asset Retirement Obligations,” on page 74.

TABLE III – RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES¹

The company's results of operations from oil and gas producing activities for the years 2003, 2002 and 2001 are shown in the following table. Net income from exploration and production

activities as reported on pages 30 and 31 reflects income taxes computed on an effective rate basis. In accordance with FAS No. 69, income taxes in Table III are based on statutory tax rates, reflecting allowable deductions and tax credits. Interest income and expense are excluded from the results reported in Table III and from the net income amounts on pages 30 and 31.

Millions of dollars	Consolidated Companies					Affiliated Companies		Worldwide
	U.S.	Africa	Asia-Pacific	Other	Total	TCO	Hamaca	
YEAR ENDED DECEMBER 31, 2003								
Revenues from net production								
Sales	\$ 4,507	\$ 1,339	\$ 1,497	\$ 2,556	\$ 9,899	\$ 1,116	\$ 104	\$ 11,119
Transfers	4,921	1,835	3,304	1,356	11,416	–	–	11,416
Total	9,428	3,174	4,801	3,912	21,315	1,116	104	22,535
Production expenses excluding taxes	(1,959)	(505)	(783)	(669)	(3,916)	(117)	(20)	(4,053)
Taxes other than on income	(356)	(22)	(127)	(100)	(605)	(29)	–	(634)
Proved producing properties:								
depreciation and depletion	(1,532)	(327)	(712)	(846)	(3,417)	(97)	(4)	(3,518)
Accretion expense ²	(69)	(20)	(13)	(26)	(128)	(2)	–	(130)
Exploration expenses	(193)	(123)	(138)	(117)	(571)	–	–	(571)
Unproved properties valuation	(20)	(20)	(9)	(41)	(90)	–	–	(90)
Other (expense) income ³	(173)	(173)	(504)	(175)	(1,025)	(4)	(35)	(1,064)
Results before income taxes	5,126	1,984	2,515	1,938	11,563	867	45	12,475
Income tax expense	(1,890)	(1,410)	(1,447)	(831)	(5,578)	(260)	–	(5,838)
RESULTS OF PRODUCING OPERATIONS	\$ 3,236	\$ 574	\$ 1,068	\$ 1,107	\$ 5,985	\$ 607	\$ 45	\$ 6,637
YEAR ENDED DECEMBER 31, 2002⁴								
Revenues from net production								
Sales	\$ 2,737	\$ 1,121	\$ 1,410	\$ 2,080	\$ 7,348	\$ 955	\$ 44	\$ 8,347
Transfers	4,425	1,663	3,090	1,202	10,380	–	–	10,380
Total	7,162	2,784	4,500	3,282	17,728	955	44	18,727
Production expenses excluding taxes	(1,982)	(415)	(844)	(606)	(3,847)	(130)	(4)	(3,981)
Taxes other than on income	(339)	(24)	(114)	(77)	(554)	(36)	–	(590)
Proved producing properties:								
depreciation and depletion	(1,483)	(314)	(660)	(654)	(3,111)	(86)	(5)	(3,202)
FAS 19 abandonment provision ²	(94)	(38)	(13)	(40)	(185)	(5)	–	(190)
Exploration expenses	(216)	(106)	(109)	(160)	(591)	–	–	(591)
Unproved properties valuation	(35)	(14)	(9)	(67)	(125)	–	–	(125)
Other (expense) income ³	(359)	(179)	(399)	59	(878)	(5)	(12)	(895)
Results before income taxes	2,654	1,694	2,352	1,737	8,437	693	23	9,153
Income tax expense	(933)	(1,202)	(1,434)	(677)	(4,246)	(208)	–	(4,454)
RESULTS OF PRODUCING OPERATIONS	\$ 1,721	\$ 492	\$ 918	\$ 1,060	\$ 4,191	\$ 485	\$ 23	\$ 4,699
YEAR ENDED DECEMBER 31, 2001⁴								
Revenues from net production								
Sales	\$ 6,557	\$ 1,147	\$ 1,264	\$ 2,181	\$ 11,149	\$ 673	\$ 6	\$ 11,828
Transfers	2,458	1,913	2,796	1,107	8,274	–	–	8,274
Total	9,015	3,060	4,060	3,288	19,423	673	6	20,102
Production expenses excluding taxes	(2,047)	(425)	(804)	(664)	(3,940)	(114)	(6)	(4,060)
Taxes other than on income	(395)	(22)	(52)	(23)	(492)	(28)	–	(520)
Proved producing properties: depreciation,								
depletion and abandonment provision	(1,614)	(344)	(498)	(658)	(3,114)	(80)	(1)	(3,195)
Exploration expenses	(424)	(132)	(234)	(298)	(1,088)	–	–	(1,088)
Unproved properties valuation	(38)	(33)	(9)	(77)	(157)	–	–	(157)
Other (expense) income ³	(1,653)	(110)	(209)	(5)	(1,977)	9	2	(1,966)
Results before income taxes	2,844	1,994	2,254	1,563	8,655	460	1	9,116
Income tax expense	(1,074)	(1,455)	(1,432)	(620)	(4,581)	(138)	–	(4,719)
RESULTS OF PRODUCING OPERATIONS	\$ 1,770	\$ 539	\$ 822	\$ 943	\$ 4,074	\$ 322	\$ 1	\$ 4,397

¹ The value of owned production consumed on lease as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.

² See Note 25 on page 74, FAS 143 "Asset Retirement Obligations."

³ Includes net sulfur income, foreign currency transaction gains and losses, certain significant impairment write-downs, miscellaneous expenses, etc. Also includes net income from related oil and gas activities that do not have oil and gas reserves attributed to them (for example, net income from technical and operating service agreements) and items identified in the Management's Discussion and Analysis on pages 30 and 31.

⁴ 2002 and 2001 include certain reclassifications to conform to 2003 presentation.



Unaudited

TABLE IV – RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES – UNIT PRICES AND COSTS^{1,2}

	Consolidated Companies					Affiliated Companies		Worldwide
	U.S.	Africa	Asia-Pacific	Other	Total	TCO	Hamaca	
YEAR ENDED DECEMBER 31, 2003								
Average sales prices								
Liquids, per barrel	\$ 26.66	\$ 28.54	\$ 24.83	\$ 27.56	\$ 26.69	\$ 22.07	\$ 17.06	\$ 26.24
Natural gas, per thousand cubic feet	5.01	0.04	3.51	2.58	4.08	0.68	0.33	3.96
Average production costs, per barrel	5.82	4.42	3.93	3.99	4.79	2.04	3.24	4.60
YEAR ENDED DECEMBER 31, 2002								
Average sales prices								
Liquids, per barrel	\$ 21.34	\$ 24.33	\$ 21.76	\$ 23.31	\$ 22.36	\$ 18.16	\$ 18.91	\$ 22.03
Natural gas, per thousand cubic feet	2.89	0.04	2.67	2.11	2.62	0.57	–	2.55
Average production costs, per barrel ³	5.48	3.49	3.88	3.59	4.44	2.19	1.58	4.29
YEAR ENDED DECEMBER 31, 2001								
Average sales prices								
Liquids, per barrel	\$ 21.33	\$ 23.70	\$ 20.11	\$ 22.59	\$ 21.68	\$ 13.31	\$ 12.45	\$ 21.08
Natural gas, per thousand cubic feet	4.38	0.04	3.04	2.51	3.78	0.47	–	3.69
Average production costs, per barrel ³	5.32	3.23	3.94	4.03	4.45	2.04	13.09	4.31

¹ The value of owned production consumed on lease as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.

² Natural gas converted to oil-equivalent gas (OEG) barrels at a rate of 6 MCF = 1 OEG barrel.

³ Conformed to 2003 presentation to exclude taxes.

TABLE V – RESERVE QUANTITY INFORMATION

The company's estimated net proved underground oil and gas reserves and changes thereto for the years 2003, 2002 and 2001 are shown in the following table. Proved reserves are estimated by company asset teams composed of earth scientists and reservoir engineers. These proved reserve estimates are reviewed annually by the company's Reserves Advisory Committee to ensure that rigorous professional standards and the reserves definitions prescribed by the U.S. Securities and Exchange Commission are consistently applied throughout the company.

Proved reserves are the estimated quantities that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Due to the inherent uncertainties and the limited nature of reservoir data, estimates of underground reserves are subject to change as additional information becomes available.

Proved reserves do not include additional quantities that may result from extensions of currently proved areas or from applying secondary or tertiary recovery processes not yet tested and determined to be economic.

Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods.

Net reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate.

TABLE V – RESERVE QUANTITY INFORMATION – Continued

ChevronTexaco operates, under a risked service agreement, Venezuela's Block LL-652, located in the northeast section of Lake Maracaibo. ChevronTexaco is accounting for LL-652 as an oil and gas activity and, at December 31, 2003, had recorded

19 million barrels of proved crude oil reserves and 89 billion cubic feet of proved natural gas reserves.

No reserve quantities have been recorded for the company's other service agreement – the Boscan Field in Venezuela. During the year, an agreement was reached that extends production rights on the Chuchupa and other gas fields in Colombia.

	NET PROVED RESERVES OF CRUDE OIL, CONDENSATE AND NATURAL GAS LIQUIDS								NET PROVED RESERVES OF NATURAL GAS							
	Consolidated Companies					Affiliates			Consolidated Companies					Affiliates		World-wide
	U.S.	Africa	Asia-Pacific	Other	Total	TCO	Hamaca	World-wide	U.S.	Africa	Asia-Pacific	Other	Total	TCO	Hamaca	
RESERVES AT JANUARY 1, 2001	2,614	1,505	1,894	822	6,835	1,310	374	8,519	7,923	772	4,442	2,991	16,128	1,683	33	17,844
Changes attributable to:																
Revisions	(225)	45	135	(60)	(105)	46	(2)	(61)	(20)	780	330	(10)	1,080	317	–	1,397
Improved recovery	79	35	47	51	212	–	–	212	24	7	11	16	58	–	–	58
Extensions and discoveries	67	88	34	40	229	88	115	432	587	329	164	445	1,525	130	9	1,664
Purchases ¹	1	–	–	–	1	146	–	147	41	–	6	6	53	187	–	240
Sales ²	(11)	–	–	–	(11)	–	–	(11)	(180)	–	–	–	(180)	–	–	(180)
Production	(224)	(129)	(204)	(108)	(665)	(49)	–	(714)	(988)	(16)	(194)	(360)	(1,558)	(55)	–	(1,613)
RESERVES AT DECEMBER 31, 2001	2,301	1,544	1,906	745	6,496	1,541	487	8,524	7,387	1,872	4,759	3,088	17,106	2,262	42	19,410
Changes attributable to:																
Revisions	(116)	164	(114)	17	(49)	199	–	150	(598)	277	390	92	161	293	1	455
Improved recovery	99	82	22	36	239	–	–	239	21	42	4	10	77	–	–	77
Extensions and discoveries	48	301	85	8	442	–	–	442	395	134	260	103	892	–	–	892
Purchases ¹	8	–	–	–	8	–	–	8	93	–	8	–	101	–	–	101
Sales ²	(3)	–	–	–	(3)	–	–	(3)	(3)	–	–	–	(3)	–	–	(3)
Production	(220)	(115)	(195)	(109)	(639)	(51)	(2)	(692)	(878)	(27)	(257)	(369)	(1,531)	(66)	–	(1,597)
RESERVES AT DECEMBER 31, 2002	2,117	1,976	1,704	697	6,494	1,689	485	8,668	6,417	2,298	5,164	2,924	16,803	2,489	43	19,335
Changes attributable to:																
Revisions	(9)	(1)	48	19	57	200	–	257	(606)	342	915	976	1,627	109	70	1,806
Improved recovery	53	36	54	52	195	–	–	195	23	17	15	35	90	–	–	90
Extensions and discoveries	124	24	18	26	192	–	–	192	388	3	88	47	526	–	–	526
Purchases ¹	1	–	–	12	13	–	–	13	8	–	7	55	70	–	–	70
Sales ²	(23)	–	(42)	(1)	(66)	–	–	(66)	(64)	–	–	(6)	(70)	–	–	(70)
Production	(205)	(112)	(179)	(109)	(605)	(49)	(6)	(660)	(813)	(18)	(296)	(366)	(1,493)	(72)	(1)	(1,566)
RESERVES AT DECEMBER 31, 2003	2,058	1,923	1,603	696	6,280	1,840	479	8,599	5,353	2,642	5,893	3,665	17,553	2,526	112	20,191
DEVELOPED RESERVES																
At January 1, 2001	2,083	976	1,276	538	4,873	795	–	5,668	6,408	294	3,108	2,347	12,157	1,019	–	13,176
At December 31, 2001	1,887	923	1,491	517	4,818	1,007	38	5,863	6,246	444	3,170	2,231	12,091	1,477	6	13,574
At December 31, 2002	1,766	1,042	1,297	529	4,634	999	63	5,696	5,636	582	3,196	2,157	11,571	1,474	6	13,051
At December 31, 2003	1,651	1,059	1,229	522	4,461	1,304	140	5,905	4,801	954	3,850	3,043	12,648	1,789	52	14,489

¹ Includes reserves acquired through property exchanges.

² Includes reserves disposed of through property exchanges.

INFORMATION ON CANADIAN OIL SANDS NET PROVED RESERVES NOT INCLUDED ABOVE:

In addition to conventional liquids and natural gas proved reserves, ChevronTexaco has significant interests in proved oil sands reserves in Canada associated with the Athabasca project. For internal management purposes, ChevronTexaco views these reserves and their development as an integral part of total upstream operations. However, U.S. Securities and Exchange Commission regulations define these reserves as mining-related and not a part of conventional oil and gas reserves. Net proved oil sands reserves were 171 million barrels as of December 31, 2003. Production began in late 2002.

The oil sands reserves are not considered in the standardized measure of discounted future net cash flows for conventional oil and gas reserves, which is found on page 82.

TABLE VI – STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATED TO PROVED OIL AND GAS RESERVES

The standardized measure of discounted future net cash flows, related to the preceding proved oil and gas reserves, is calculated in accordance with the requirements of FAS No. 69. Estimated future cash inflows from production are computed by applying year-end prices for oil and gas to year-end quantities of estimated net proved reserves. Future price changes are limited to those provided by contractual arrangements in existence at the end of each reporting year. Future development and production costs are those estimated future expenditures necessary to develop and produce year-end estimated proved reserves based on year-end cost indices, assuming continuation of year-end economic conditions, and include estimated costs for asset retirement obligations. Estimated future income taxes are calculated by applying appropriate year-end statutory tax rates. These rates reflect allowable deductions and tax credits and are applied to estimated future pretax net cash flows, less the tax basis of related

assets. Discounted future net cash flows are calculated using 10 percent midperiod discount factors. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced.

The information provided does not represent management's estimate of the company's expected future cash flows or value of proved oil and gas reserves. Estimates of proved reserve quantities are imprecise and change over time as new information becomes available. Moreover, probable and possible reserves, which may become proved in the future, are excluded from the calculations. The arbitrary valuation prescribed under FAS No. 69 requires assumptions as to the timing and amount of future development and production costs. The calculations are made as of December 31 each year and should not be relied upon as an indication of the company's future cash flows or value of its oil and gas reserves.

Millions of dollars	Consolidated Companies					Affiliated Companies		
	U.S.	Africa	Asia-Pacific	Other	Total	TCO	Hamaca	Worldwide
AT DECEMBER 31, 2003								
Future cash inflows from production	\$ 87,079	\$ 55,532	\$ 59,319	\$ 29,987	\$ 231,917	\$ 56,485	\$ 9,018	\$ 297,420
Future production costs	(25,049)	(8,237)	(17,776)	(6,334)	(57,396)	(6,099)	(1,878)	(65,373)
Future development costs	(4,208)	(4,524)	(4,161)	(1,971)	(14,864)	(6,066)	(463)	(21,393)
Future income taxes	(19,567)	(25,369)	(15,925)	(7,888)	(68,749)	(12,520)	(2,270)	(83,539)
Undiscounted future net cash flows	38,255	17,402	21,457	13,794	90,908	31,800	4,407	127,115
10 percent midyear annual discount for timing of estimated cash flows	(17,177)	(8,482)	(9,405)	(5,039)	(40,103)	(20,140)	(2,949)	(63,192)
STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS	\$ 21,078	\$ 8,920	\$ 12,052	\$ 8,755	\$ 50,805	\$ 11,660	\$ 1,458	\$ 63,923
AT DECEMBER 31, 2002*								
Future cash inflows from production	\$ 77,912	\$ 52,513	\$ 59,550	\$ 26,531	\$ 216,506	\$ 52,457	\$ 9,777	\$ 278,740
Future production costs	(26,315)	(6,435)	(14,086)	(5,970)	(52,806)	(4,959)	(1,730)	(59,495)
Future development costs	(3,633)	(3,454)	(4,505)	(1,868)	(13,460)	(5,377)	(578)	(19,415)
Future income taxes	(16,231)	(25,060)	(17,781)	(6,797)	(65,869)	(11,899)	(2,540)	(80,308)
Undiscounted future net cash flows	31,733	17,564	23,178	11,896	84,371	30,222	4,929	119,522
10 percent midyear annual discount for timing of estimated cash flows	(13,872)	(8,252)	(9,971)	(3,691)	(35,786)	(18,964)	(3,581)	(58,331)
STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS	\$ 17,861	\$ 9,312	\$ 13,207	\$ 8,205	\$ 48,585	\$ 11,258	\$ 1,348	\$ 61,191
AT DECEMBER 31, 2001*								
Future cash inflows from production	\$ 54,238	\$ 28,019	\$ 43,389	\$ 20,432	\$ 146,078	\$ 29,433	\$ 5,922	\$ 181,433
Future production costs	(25,851)	(6,640)	(16,131)	(6,381)	(55,003)	(4,325)	(584)	(59,912)
Future development costs	(5,020)	(3,466)	(4,714)	(2,492)	(15,692)	(4,540)	(509)	(20,741)
Future income taxes	(7,981)	(10,476)	(9,858)	(4,370)	(32,685)	(5,805)	(1,642)	(40,132)
Undiscounted future net cash flows	15,386	7,437	12,686	7,189	42,698	14,763	3,187	60,648
10 percent midyear annual discount for timing of estimated cash flows	(6,882)	(3,609)	(5,857)	(2,602)	(18,950)	(9,121)	(2,433)	(30,504)
STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS	\$ 8,504	\$ 3,828	\$ 6,829	\$ 4,587	\$ 23,748	\$ 5,642	\$ 754	\$ 30,144

* 2002 and 2001 include certain reclassifications to conform to 2003 presentation.

TABLE VII – CHANGES IN THE STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS FROM PROVED RESERVES

The changes in present values between years, which can be significant, reflect changes in estimated proved reserve quantities and prices and assumptions used in forecasting production

volumes and costs. Changes in the timing of production are included with “Revisions of previous quantity estimates.”

Millions of dollars	Consolidated Companies			Affiliated Companies			Worldwide		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
PRESENT VALUE AT JANUARY 1	\$ 48,585	\$ 23,748	\$ 59,802	\$ 12,606	\$ 6,396	\$ 6,186	\$ 61,191	\$ 30,144	\$ 65,988
Sales and transfers of oil and gas produced net of production costs	(16,794)	(13,327)	(15,161)	(1,054)	(829)	(531)	(17,848)	(14,156)	(15,692)
Development costs incurred	3,451	3,695	3,967	750	800	541	4,201	4,495	4,508
Purchases of reserves	97	181	40	–	–	778	97	181	818
Sales of reserves	(839)	(42)	(366)	–	–	–	(839)	(42)	(366)
Extensions, discoveries and improved recovery less related costs	5,445	7,472	2,747	–	–	484	5,445	7,472	3,231
Revisions of previous quantity estimates	1,168	104	524	652	917	400	1,820	1,021	924
Net changes in prices, development and production costs	2,054	41,044	(59,995)	(1,187)	6,722	(2,457)	867	47,766	(62,452)
Accretion of discount	7,903	3,987	10,144	1,709	895	876	9,612	4,882	11,020
Net change in income tax	(264)	(18,277)	22,046	(359)	(2,295)	119	(623)	(20,572)	22,165
Net change for the year	2,221	24,837	(36,054)	511	6,210	210	2,732	31,047	(35,844)
PRESENT VALUE AT DECEMBER 31	\$ 50,806	\$ 48,585	\$ 23,748	\$ 13,117	\$ 12,606	\$ 6,396	\$ 63,923	\$ 61,191	\$ 30,144

Worldwide – Includes Equity in Affiliates

Thousands of barrels per day, except natural gas data, which is millions of cubic feet per day

	2003	2002	2001	2000	1999
UNITED STATES					
Gross production of crude oil and natural gas liquids	602	657	670	730	781
Net production of crude oil and natural gas liquids	562	602	614	667	712
Refinery input ²	951	979	1,336	1,390	1,534
Sales of refined products ²	1,514	1,600	2,500	2,667	2,623
Sales of natural gas liquids	194	241	185	170	415
Total sales of petroleum products	1,708	1,841	2,685	2,837	3,038
Gross production of natural gas	2,603	2,945	3,167	3,485	3,757
Net production of natural gas ³	2,228	2,405	2,706	2,910	3,145
Net production of oil equivalents	933	1,003	1,065	1,152	1,236
Sales of natural gas	3,871	5,463	7,830	7,302	6,534
INTERNATIONAL					
Gross production of crude oil and natural gas liquids	1,681	1,765	1,852	1,640	1,632
Net production of crude oil and natural gas liquids	1,246	1,295	1,345	1,330	1,337
Refinery input	1,040	1,100	1,136	1,150	1,235
Sales of refined products	2,224	2,175	2,454	2,521	2,621
Sales of natural gas liquids	107	131	115	67	58
Total sales of petroleum products	2,331	2,306	2,569	2,588	2,679
Gross production of natural gas	2,203	2,120	1,949	1,867	1,748
Net production of natural gas ³	2,064	1,971	1,711	1,556	1,512
Net production of oil equivalents	1,590	1,623	1,630	1,589	1,589
Sales of natural gas	1,951	3,131	2,675	2,398	2,342
TOTAL WORLDWIDE					
Gross production of crude oil and natural gas liquids	2,283	2,422	2,522	2,370	2,413
Net production of crude oil and natural gas liquids	1,808	1,897	1,959	1,997	2,049
Refinery input ²	1,991	2,079	2,472	2,540	2,769
Sales of refined products ²	3,738	3,775	4,954	5,188	5,244
Sales of natural gas liquids	301	372	300	237	473
Total sales of petroleum products	4,039	4,147	5,254	5,425	5,717
Gross production of natural gas	4,806	5,065	5,116	5,352	5,505
Net production of natural gas ³	4,292	4,376	4,417	4,466	4,657
Net production of oil equivalents	2,523	2,626	2,695	2,741	2,825
Sales of natural gas	5,822	8,594	10,505	9,700	8,876
Worldwide – Excludes Equity in Affiliates					
Number of wells completed (net) ⁴					
Oil and gas	1,472	1,349	1,698	1,665	1,542
Dry	36	49	75	67	74
Productive oil and gas wells (net) ⁴	48,155	50,320	47,388	N/A	N/A

¹ Gross production represents the company's share of total production before deducting lessors' royalties. Net production is gross production minus royalties paid to lessors.

² 2001 and prior include sales volumes and refinery inputs of units sold as a condition of the merger.

³ Includes gas consumed on lease:

United States	65	64	64	79	87
International	262	256	262	244	237
Total	327	320	326	323	324

⁴ Net wells include all those wholly owned and the sum of fractional interests in those that are joint ventures, unit operations or similar wells. Also includes wells temporarily shut in that are capable of producing.



DAVID J. O'REILLY

PETER J. ROBERTSON

SAMUEL H. ARMACOST

ROBERT J. EATON

SAM GINN



CARLA A. HILLS

FRANKLYN G. JENIFER

J. BENNETT JOHNSTON

SAM NUNN

CHARLES R. SHOEMATE



FRANK A. SHRONTZ*

THOMAS A. VANDERSLICE*

CARL WARE

JOHN A. YOUNG*

BOARD OF DIRECTORS

David J. O'Reilly, 57

Chairman of the Board and Chief Executive Officer since 2001. He was elected Chairman and Chief Executive Officer of Chevron Corporation in 2000. Previously he was elected a Director and Vice Chairman, responsible for worldwide exploration and production and corporate human resources, in 1998; President of Chevron Products Company in 1994; and a Vice President in 1991. He joined Chevron-Texaco in 1968. He is Chairman of the American Petroleum Institute's Board of Directors.

Peter J. Robertson, 57

Vice Chairman of the Board and a Director since 2002. He is responsible for the company's worldwide exploration, production and global gas businesses. He also is a Director of Sasol Chevron Holdings Ltd. Previously he was elected President, Chevron Overseas Petroleum Inc., in 2000; a Corporate Vice President and President, Chevron U.S.A. Production Company, responsible for North American exploration and production, in 1997. He joined ChevronTexaco in 1973.

Samuel H. Armacost, 64

Director since 1982. He is Chairman of SRI International. Previously he was a Managing Director of Weiss, Peck & Greer LLC. He also is a Director of The James Irvine Foundation, Del Monte Foods Company and Exponent, Inc. (3, 4)

Robert J. Eaton, 64

Director since 2001. He is retired Chairman of the Board of Management of DaimlerChrysler AG. Previously he was Chairman of the Board and Chief Executive Officer of Chrysler Corporation and was elected a Texaco Inc. Director in 2000. He also is a Director of International Paper Company. (2, 4)

Sam Ginn, 66

Director since 1989. He is retired Chairman of Vodafone AirTouch, PLC. Previously he was Chairman of the Board and Chief Executive Officer of AirTouch Communications, Inc., and Chairman of the Board, President and Chief Executive Officer of Pacific Telesis Group. He also is a Director of Hewlett-Packard Company and Templeton Emerging Markets Investment Trust PLC. (1)

Carla A. Hills, 70

Director since 1993. She is Chairman and Chief Executive Officer of Hills & Company International Consultants. She served as U.S. Trade Representative from 1989 to 1993 and Secretary of the Department of Housing and Urban Development from 1975 to 1977. She is a Director of American International Group, Inc.; Lucent Technologies Inc.; and Time Warner Inc. (3, 4)

Franklyn G. Jenifer, 65

Director since 2001. He is President of The University of Texas at Dallas. Previously he was President of Howard University and Chancellor of the Massachusetts Board of Regents of Higher Education. He was elected a Texaco Inc. Director in 1993. He is a Director of the Texas Science and Technology Council, Dallas Citizens Council and the Monitoring Committee for the Louisiana Desegregation Settlement Agreement. (1)

J. Bennett Johnston, 71

Director since 1997. He is Chief Executive Officer of Johnston & Associates, a governmental and business consulting firm. He served as a U.S. Senator from Louisiana for 24 years. He is President of the U.S. Pacific Economic Cooperation Council and a Director of Nexant, Inc., and Freeport-McMoRan Copper & Gold Inc. (2, 4)

Sam Nunn, 65

Director since 2001. He is Co-Chairman and Chief Executive Officer of the Nuclear Threat Initiative, a charitable organization. He also is a distinguished professor at the Sam Nunn School of International Affairs, Georgia Tech. He served as a U.S. Senator from Georgia for 24 years and was elected a Texaco Inc. Director in 1997. He is a Director of The Coca-Cola Company; Dell Inc.; Internet Security Systems, Inc.; Scientific-Atlanta, Inc.; and General Electric Company. (2, 3)

Charles R. Shoemate, 64

Director since 2001. He is retired Chairman of the Board, President and Chief Executive Officer of Bestfoods. He was elected a Texaco Inc. Director in 1998. He is a Director of International Paper Company and CIGNA Corporation. (1)

Frank A. Shrontz, 72*

Director since 1996. He is retired Chairman of the Board of The Boeing Company. From 1973 to 1977, he served as Assistant Secretary of Defense and Assistant Secretary of the Air Force. He also is a Director of Boise Cascade Corporation. (2, 4)

Thomas A. Vanderslice, 72*

Director since 2001. He is a private investor. Previously he was Chairman and Chief Executive Officer of M/A-COM, Inc.; Chairman and Chief Executive Officer of Apollo Computer, Inc.; and President and Chief Operating Officer of GTE Corporation. He was elected a Texaco Inc. Director in 1980. He is a Director of W.R. Grace & Co. (1)

Carl Ware, 60

Director since 2001. He is Senior Adviser to the Chief Executive Officer of The Coca-Cola Company and retired Executive Vice President of Global Public Affairs and Administration for The Coca-Cola Company. Previously he was President of The Coca-Cola Company's Africa Group. He is a Director of Georgia Power Company; PGA TOUR Golf Course Properties, Inc.; and National Life of Vermont. (2, 3)

John A. Young, 71*

Director since 1985. He is Chairman of the Board of CIPHERGEN Biosystems, Inc. Previously he was Vice Chairman of the Board of Novell, Inc.; Vice Chairman of the Board of SmithKline Beecham PLC; and President and Chief Executive Officer of Hewlett-Packard Company. He serves on numerous boards, including Affymetrix, Inc., and Lucent Technologies Inc. (1)

*Retiring Director; will not stand for reelection at the April 28, 2004, Annual Meeting.

COMMITTEES OF THE BOARD

- 1) Audit: Sam Ginn, Chairman
- 2) Public Policy: J. Bennett Johnston, Chairman
- 3) Board Nominating and Governance: Carla A. Hills, Chairwoman
- 4) Management Compensation: Samuel H. Armacost, Chairman



LYDIA I. BEEBE

JOHN E. BETHANCOURT

STEPHEN J. CROWE

JOHN D. GASS

CHARLES A. JAMES

GEORGE L. KIRKLAND



DAVID M. KRATTEBOL

SAM LAIDLAW

JOHN W. McDONALD

DONALD L. PAUL

ALAN R. PRESTON

THOMAS R. SCHUTTISH



JOHN S. WATSON

RAYMOND I. WILCOX

PATRICIA A. WOERTZ

PATRICIA E. YARRINGTON

RHONDA I. ZYGOCKI

CORPORATE OFFICERS

Lydia I. Beebe, 51
Corporate Secretary since 2001. Previously Chevron Corporate Secretary since 1995; Senior Manager, Chevron Tax Department; Manager, Federal Tax Legislation; Staff Attorney; and Chevron Legal Representative in Washington, D.C. Joined ChevronTexaco in 1977.

John E. Bethancourt, 52
Executive Vice President, Technology and Services, since July 2003. Responsible for the technology companies and health, environment and safety as well as project resources, additives and coal operations. Previously ChevronTexaco Vice President, Human Resources; Texaco Corporate Vice President and President, Production Operations, Texaco Worldwide Exploration and Production. Joined ChevronTexaco in 1974.

Stephen J. Crowe, 56
Vice President and Comptroller since 2001. Previously Chevron Vice President and Comptroller; Vice President, Finance, Chevron Products Company; and Assistant Comptroller, Chevron Corporation. Joined ChevronTexaco in 1972.

John D. Gass, 51
Corporate Vice President and President, ChevronTexaco Global Gas, since June 2003. Responsible also for ChevronTexaco's shipping company and pipeline operations. Director of Sasol Chevron Holdings Ltd. Previously Managing Director, ChevronTexaco Southern Africa Strategic Business Unit, and Managing Director, Chevron Australia Pty Ltd. Joined ChevronTexaco in 1974.

Charles A. James, 49
Vice President and General Counsel since 2002. Previously Assistant Attorney General, Antitrust Division, U.S. Department of Justice, in President George W. Bush's administration; Chair, Antitrust and Trade Regulation Practice – Jones, Day, Reavis & Pogue, Washington, D.C. Joined ChevronTexaco in 2002.

George L. Kirkland, 53
Corporate Vice President and President, ChevronTexaco Overseas Petroleum Inc., since 2002. Responsible for exploration and production activities outside North America. Previously President, ChevronTexaco Exploration and Production Company, responsible for exploration and production activities in North America, and President, Chevron U.S.A. Production Company. Joined ChevronTexaco in 1974.

David M. Krattebol, 59
Vice President and Treasurer since 2001. Previously Chevron Vice President and Treasurer; President, Chevron San Jorge; Vice President, Logistics and Trading, Chevron Products Company; Vice President, Finance, Chevron Products Company; and Vice President, Finance, Chevron Overseas Petroleum Inc. Joined ChevronTexaco in 1971.

Sam Laidlaw, 48
Executive Vice President, Business Development, since May 2003. Responsible for identifying and developing new, large-scale business opportunities worldwide. Previously Chief Executive Officer of Enterprise Oil PLC, at the time Europe's largest independent oil and gas company. Prior to that President of Amerada Hess Corporation. Non-Executive Director of Hanson PLC. Joined ChevronTexaco in May 2003.

John W. McDonald, 52
Vice President, Strategic Planning, since 2002. Previously President and Managing Director, ChevronTexaco Upstream Europe, ChevronTexaco Overseas Petroleum Inc.; Vice President, Gulf of Mexico Offshore Division, Texaco Exploration and Production Inc.; further operating assignments in Canada and South America; and from the United States, assignments covering the Americas and Africa. Joined ChevronTexaco in 1975.

Donald L. Paul, 57
Vice President and Chief Technology Officer since 2001. Previously Chevron Corporate Vice President, Technology and Environmental Affairs, and President, Chevron Technology Ventures; President, Chevron Canada Resources; and President, Chevron Petroleum Technology Company. Joined ChevronTexaco in 1975.

Alan R. Preston, 52
Vice President, Human Resources, since July 2003. Previously ChevronTexaco General Manager, Global Remuneration; General Manager, Organization/Compensation, Chevron Corporation; General Manager, Human Resources, Chevron Products Company. Joined ChevronTexaco in 1973.

Thomas R. Schuttish, 56
General Tax Counsel since 2002. Previously ChevronTexaco Assistant General Tax Counsel and Chevron Assistant General Tax Counsel. Joined ChevronTexaco in 1980.

John S. Watson, 47
Vice President and Chief Financial Officer since 2001. Director of Dynegy Inc. Previously Chevron Vice President and Chief Financial Officer; Director, Caltex Petroleum Corporation; Vice President, Strategic Planning, Chevron Corporation; President, Chevron Canada Limited; and General Manager, Strategic Planning and Quality, Chevron U.S.A. Products Company. Joined ChevronTexaco in 1980.

Raymond I. Wilcox, 58
Corporate Vice President and President, ChevronTexaco Exploration and Production Company, since 2002. Director of Dynegy Inc. Previously ChevronTexaco Managing Director, Nigeria/Mid-Africa Strategic Business Unit, and Chairman and Managing Director, Chevron Nigeria Limited. Joined ChevronTexaco in 1968.

Patricia A. Woertz, 51
Executive Vice President, Global Downstream, since 2001. Responsible for worldwide refining, marketing, lubricants, and supply and trading. Director of the American Petroleum Institute. Previously Chevron Corporate Vice President and President, Chevron Products Company, and President, Chevron International Oil Company. Joined ChevronTexaco in 1977.

Patricia E. Yarrington, 47
Vice President, Policy, Government and Public Affairs, since 2002. Director of Chevron Phillips Chemical Company LLC. Previously ChevronTexaco Vice President, Strategic Planning; Chevron Vice President, Strategic Planning; President, Chevron Canada Limited; and Comptroller, Chevron Products Company. Joined ChevronTexaco in 1980.

Rhonda I. Zygocki, 46
Vice President, Health, Environment and Safety, since April 2003. Previously Managing Director, ChevronTexaco Australia Pty Ltd; Adviser to the Chairman of the Board, Chevron Corporation; Manager of Strategic Planning, Chevron Corporation; and Chief Financial Officer, Chevron Canada Resources. Joined ChevronTexaco in 1980.

EXECUTIVE COMMITTEE

David J. O'Reilly, Peter J. Robertson, John E. Bethancourt, Charles A. James, Sam Laidlaw, John S. Watson and Patricia A. Woertz. Lydia I. Beebe, Secretary.

STOCKHOLDER AND INVESTOR INFORMATION

STOCK EXCHANGE LISTING

ChevronTexaco common stock is listed on the New York and Pacific stock exchanges. The symbol is "CVX."

STOCKHOLDER INFORMATION

Questions about stock ownership, changes of address, dividend payments or direct deposit of dividends should be directed to ChevronTexaco's transfer agent and registrar:

Mellon Investor Services LLC
85 Challenger Road
Ridgefield Park, NJ 07660-2108
800 368 8357
www.melloninvestor.com

The Mellon Investor Services Program (800 842 7629, same address as above) features dividend reinvestment, optional cash investments of \$50 to \$100,000 a year, automatic stock purchase and safekeeping of stock certificates.

DIVIDEND PAYMENT DATES

Quarterly dividends on common stock are paid, following declaration by the Board of Directors, on or about the 10th day of March, June, September and December. Direct

deposit of dividends is available to stockholders. For information, contact Mellon Investor Services. (See *Stockholder Information*.)

INVESTOR INFORMATION

Securities analysts, portfolio managers and representatives of financial institutions may contact: Investor Relations
ChevronTexaco Corporation
6001 Bollinger Canyon Road, Bldg. A
San Ramon, CA 94583-2324
925 842 5690
Email: invest@chevrontexaco.com

ANNUAL MEETING

The Annual Meeting of stockholders will be held at 8:00 a.m., Wednesday, April 28, 2004, at: ChevronTexaco Corporation
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324

Meeting notice and proxy materials are mailed in advance to stockholders, who are urged to study the materials and complete the proxy card. All stockholders should sign the proxy card and return it promptly so their shares are represented in the final vote.

PUBLICATIONS AND OTHER NEWS SOURCES

The *Annual Report*, published in March, summarizes the company's financial performance in the preceding year and provides an outlook for the future.

ChevronTexaco's Web site, www.chevrontexaco.com, offers facts and figures about the company and the energy industry. It includes articles, news releases, speeches, quarterly earnings information, the *Proxy Statement* and the complete text of this *Annual Report*.

The Supplement to the Annual Report, containing additional financial and operating data, and Form 10-K, prepared annually for the Securities and Exchange Commission, are available after April 15 by writing to:
Comptroller's Department
ChevronTexaco Corporation
6001 Bollinger Canyon Road, A3201
San Ramon, CA 94583-2324

Details of the company's *political contributions* for 2003 are available by writing to:
Policy, Government & Public Affairs
ChevronTexaco Corporation
6001 Bollinger Canyon Road, A2108
San Ramon, CA 94583-2324

Information about *charitable and educational contributions* is available in the second half of the year on ChevronTexaco's Web site, www.chevrontexaco.com.

LEGAL NOTICE

As used in this report, the term "ChevronTexaco" and such terms as "the company," "the corporation," "our," "we" and "us" may refer to one or more of its consolidated subsidiaries or to all of them taken as a whole. All of these terms are used for convenience only and are not intended as a precise description of any of the separate companies, each of which manages its own affairs.

CORPORATE HEADQUARTERS

6001 Bollinger Canyon Road
San Ramon, CA 94583-2324
925 842 1000

This Annual Report contains forward-looking statements – identified by words such as "expects," "intends," "projects," etc. – that reflect management's current estimates and beliefs, but are not guarantees of future results. Please see "Cautionary Statements Relevant to Forward-Looking Information for the Purpose of 'Safe Harbor' Provisions of the Private Securities Litigation Reform Act of 1995" on Page 25 for a discussion of some of the factors that could cause actual results to differ materially.

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PHOTOGRAPHY: Page 6: (third from left) Carmen Rojas – United States; (far right) Mauricio Denga (left) and Zinga Martine – Angola. Pages 10-11: (middle) Moses Olorunnipa – Nigeria. Page 12: (left) Almaz Bek – Kazakhstan. Page 14: Emanuel Leopoldo – Angola. Page 16: (from left) Abdenour Kamoun (left) and Ming Wang – United States; Kevin Nguyen – United States. Page 18: (from left) Khun Peerachant – Thailand; Dan Favors – United States; (front row from left) Pat Wai, Brenda Viegas (second row) Frank Chan, Janet Winters Smith, Aminin Fanandi, Phyllis London, Annie Chou (third row) Marty Schultz, Ralph Casillas, Alex Kaplenko – United States. Page 19: (second from left) Lucas Biala (left), Trainee, and Manuel Ribeiro – Angola. Page 22: (far left) Jeff Moore – United States; (third from left) MaryLou Mendez, Chevron Dealer – United States. Page 23: (second from left) Mohamad Shakil, Contractor – Pakistan; (second from right) Tonya Betts – United States.

ChevronTexaco

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