



Managing the energy portfolio

2006 Annual Report

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Demand for energy continues to rise,

posing a clear challenge for our industry:
how to develop new and better ways to produce,
process, use and deliver all forms of energy –
from conventional crude oil and natural gas to
the emerging sources of the future.

At Chevron, we recognize the world needs all
the energy we can develop, in every potential form.
We're managing our energy portfolio to deliver that
energy – and to create growth and value for our
stockholders, our customers, our business partners
and the communities where we do business.



The energy portfolio

CONVENTIONAL
ENERGY

6

UNCONVENTIONAL
ENERGY

8

EMERGING
ENERGY

10

EFFICIENT
ENERGY

12

HUMAN
ENERGY

14



A man with glasses, wearing a dark blue pinstripe suit, a light blue shirt, and a red tie, stands in a modern office hallway. He is smiling and has his hands in his pockets. The hallway has white walls and a light-colored tiled floor.

TO OUR STOCKHOLDERS

2006 was an exceptional year for our company. We continued to deliver value to our stockholders and to make strategic investments that will drive sustained, superior performance over the long term.

We reported record net income of \$17.1 billion on sales and other operating revenues of approximately \$205 billion. For the year, total stockholder return was 33.8 percent, which was more than double the rate of return delivered by the S&P 500. Return on capital employed was a strong 22.6 percent. We continued to return cash to stockholders through our stock buyback program, purchasing \$5 billion worth of shares in the open market, and we increased our annual dividend for the 19th year in a row. We are committed to exercising the capital discipline necessary to balance current returns with investments for future profitable growth.

DELIVERING RESULTS :: We completed the successful integration of Unocal after acquiring the company in 2005 and reached a number of milestones for our major capital projects, including first production at fields in Angola, Azerbaijan, Trinidad and Tobago, and the United Kingdom. Overall, we increased year-over-year production volumes by nearly 6 percent.

Our exploration program in 2006 was outstanding, reflecting the discipline and efficiency of our processes. We announced a number of discoveries, most notably in Australia, Nigeria and the U.S. Gulf of Mexico. We achieved our fifth successful year of exploration results and added more than 1 billion barrels of potentially recoverable oil and gas resources.

In the U.S. Gulf of Mexico, we completed the Jack well test, which set more than a half-dozen world records for pressure, depth and duration in the deep water. Jack clearly demonstrates the power of advanced technology to discover significant new energy resources. Chevron is one of the largest leaseholders in the deepwater Gulf of Mexico and is competitively positioned to benefit as the long-term potential of this frontier area for crude oil and natural gas exploration plays out.

In Australia, where we hold the leading natural gas resource position, significant steps were made toward securing environmental regulatory approvals necessary for the development of the Greater Gorgon Area natural gas project. We also delivered the first commissioning cargo of Australian liquefied natural gas to China aboard the Chevron-operated *Northwest Swan* vessel.

Our global refining operations delivered record earnings in 2006, due in part to high reliability and utilization. We completed a major expansion at our Mississippi refinery that increased gasoline production capacity by approximately 10 percent, and we acquired an interest in a large new export refinery under construction in India, enhancing our presence in the fast-growing Asia-Pacific region.

We set a new safety record in 2006, our fifth consecutive year of improvement. However, we will never be satisfied until we reduce the number of safety-related incidents to zero.

CHEVRON'S ENERGY PORTFOLIO :: We expect global demand for energy to continue growing. At the same time, increased competition for resources and heightened geopolitical risks are challenging customary supply growth options. In this kind of environment, energy portfolio diversification is an increasingly important means for supplying consumers around the globe with affordable, reliable energy.

Our current asset and investment portfolio is diverse. We have a strong queue of capital projects in progress, and our capital and exploratory budget for 2007 of \$19.6 billion reflects the concentrated development

phases of many of these key projects. Our investments are focused on creating new legacy positions in key conventional energy basins, expanding our assets and capabilities in unconventional resources, and investing in emerging sources of energy such as gas-to-liquids and biofuels. This portfolio, with investments balanced by location, by energy source and by time to first production, offers a strong foundation for sustained growth in even the most challenging of environments.

HUMAN ENERGY :: At the center of our energy portfolio are the men and women of Chevron, our "human energy." They run our operations safely, reliably and efficiently, in even the toughest conditions. They develop

The people of Chevron have a pioneering and ingenious spirit that enables the company to continue expanding the boundaries of energy.

technology that improves our operations today and creates new business opportunities for tomorrow. They ensure we contribute to a better quality of life in every community where we operate.

The people of Chevron have a pioneering and ingenious spirit that enables the company to continue expanding the boundaries of energy. They understand the importance of energy to global economic growth and human progress, and they are committed to securing the energy the world needs in innovative and value-creating ways. I am proud to be part of the team.



DAVE O'REILLY

Chairman of the Board and
Chief Executive Officer
February 28, 2007

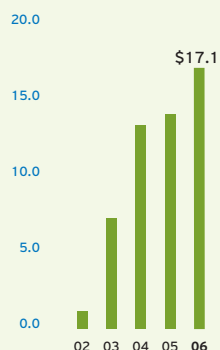
CHEVRON FINANCIAL HIGHLIGHTS

Millions of dollars, except per-share amounts

	2006	2005	% Change
Net income	\$ 17,138	\$ 14,099	22 %
Sales and other operating revenues	\$ 204,892	\$ 193,641	6 %
Capital and exploratory expenditures*	\$ 16,611	\$ 11,063	50 %
Total assets at year-end	\$ 132,628	\$ 125,833	5 %
Total debt at year-end	\$ 9,838	\$ 12,870	(24)%
Stockholders' equity at year-end	\$ 68,935	\$ 62,676	10 %
Cash provided by operating activities	\$ 24,323	\$ 20,105	21 %
Common shares outstanding at year-end (Thousands)	2,150,390	2,218,519	(3)%
Per-share data			
Net income - diluted	\$ 7.80	\$ 6.54	19 %
Cash dividends	\$ 2.01	\$ 1.75	15 %
Stockholders' equity	\$ 32.06	\$ 28.25	13 %
Common stock price at year-end	\$ 73.53	\$ 56.77	30 %
Total debt to total debt-plus-equity ratio	12.5%	17.0%	
Return on average stockholders' equity	26.0%	26.1%	
Return on capital employed (ROCE)	22.6%	21.9%	

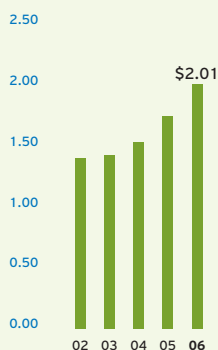
*Includes equity in affiliates

NET INCOME
Billions of dollars



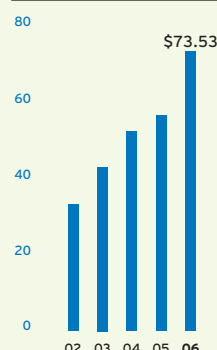
2006 net income rose on improved results in all operating segments – upstream, downstream and chemicals. Special-item charges in 2002 reduced earnings more than \$3 billion.

ANNUAL CASH DIVIDENDS
Dollars per share



The company increased its annual dividend payout for the 19th consecutive year.

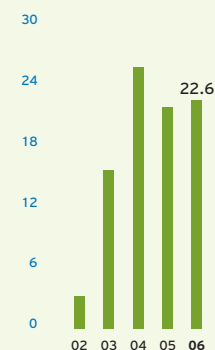
CHEVRON YEAR-END
COMMON STOCK PRICE*
Dollars per share



The company's stock price rose 30 percent in 2006, outpacing the broader market indexes.

*2002 and 2003 adjusted for stock split in 2004

RETURN ON CAPITAL
EMPLOYED
Percent



Record net income helped boost Chevron's return on capital employed to 22.6 percent. The decline from 2004 to 2005 reflected a higher capital base resulting from the Unocal acquisition.

CHEVRON OPERATING HIGHLIGHTS¹

	2006	2005	% Change
Net production of crude oil and natural gas liquids (Thousands of barrels per day)	1,732	1,669	4 %
Net production of natural gas (Millions of cubic feet per day)	4,956	4,233	17 %
Net oil-equivalent production (Thousands of oil-equivalent barrels per day)	2,667	2,517	6 %
Refinery input (Thousands of barrels per day)	1,989	1,883	6 %
Sales of refined products (Thousands of barrels per day) ²	3,621	3,725	(3)%
Net proved reserves of crude oil, condensate and natural gas liquids ³ (Millions of barrels)			
– Consolidated companies	5,294	5,626	(6)%
– Affiliated companies	2,512	2,374	6 %
Net proved reserves of natural gas ³ (Billions of cubic feet)			
– Consolidated companies	19,910	20,466	(3)%
– Affiliated companies	2,974	2,968	0 %
Net proved oil-equivalent reserves ³ (Millions of barrels)			
– Consolidated companies	8,612	9,037	(5)%
– Affiliated companies	3,008	2,869	5 %
Number of employees at year-end ⁴	55,882	53,440	5 %

¹ Includes equity in affiliates, except number of employees

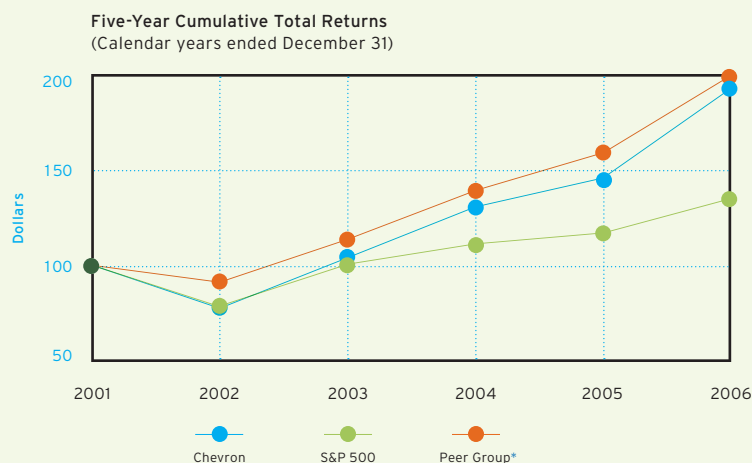
² 2005 conformed to 2006 presentation

³ At the end of the year

⁴ Excludes service station personnel

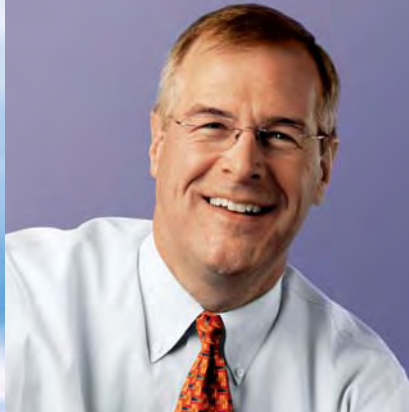
Performance Graph

The stock performance graph at right shows how an initial investment of \$100 in Chevron stock would have compared with an equal investment in the S&P 500 Index or the Competitor Peer Group. The comparison covers a five-year period beginning December 31, 2001, and ending December 31, 2006, and is weighted by market capitalization as of the beginning of each year. It includes the reinvestment of all dividends that an investor would be entitled to receive and is adjusted for stock splits. The interim measurement points show the value of \$100 invested on December 31, 2001, as of the end of each year between 2002 and 2006.



	2001	2002	2003	2004	2005	2006
Chevron	100.00	76.86	103.89	130.37	145.15	194.24
S&P 500	100.00	77.90	100.25	111.16	116.61	135.02
Peer Group*	100.00	91.08	113.07	139.35	159.21	199.29

*Peer Group: BP p.l.c.-ADS, ExxonMobil, Royal Dutch Shell plc-ADR and ConocoPhillips



"ADVANCES IN TECHNOLOGY ARE ENABLING US TO SEE MORE CLEARLY BENEATH THE EARTH'S SURFACE, TO DRILL DEEPER THAN EVER BEFORE, AND, IN THE PROCESS, TO DISCOVER SIGNIFICANT NEW VOLUMES OF CRUDE OIL AND NATURAL GAS. INNOVATIVE TECHNOLOGY AND HUMAN INGENUITY WILL CONTINUE TO EXPAND THE BOUNDARIES OF EXPLORATION."

BOBBY RYAN
VICE PRESIDENT
GLOBAL EXPLORATION
UPSTREAM



SEA LEVEL

8,000 FT

16,000 FT

24,000 FT

28,175 FT

Conventional energy

As one of the world's leading integrated energy companies, Chevron holds crude oil and natural gas assets in the key energy basins of the world. We maximize the value of our assets and keep our operations safe by applying technology in efficient, cost-effective and innovative ways. In 2006, we invested almost \$13 billion in our exploration and production operations. Global production in 2006 reached 2.67 net million barrels of oil-equivalent per day, an increase of approximately 6 percent from the previous year. The development of our queue of major capital projects is on track to grow production through the end of the decade.

< GOING DEEP (PHOTO LEFT): In 2006, Chevron conducted the Jack well test, setting a record depth for a well test in the deepwater U.S. Gulf of Mexico. It was completed and tested in 7,000 feet (2,100 meters) of water and drilled to a total depth of 28,175 feet (8,600 meters). The well penetrated the Lower Tertiary Trend, where advanced seismic technology is enabling Chevron and its partners to locate hydrocarbon deposits under dense layers of salt. Chevron is one of the largest leaseholders in the deepwater Gulf and is positioned to add significant new reserves as the trend is developed.

2006 MILESTONES

- Achieved fifth successful year of exploration results and added more than 1 billion barrels of resources
- Acquired exploration acreage in Canada, offshore Norway and Western Australia, and in the deepwater U.S. Gulf of Mexico
- Moved forward with the Tahiti development in the U.S. Gulf of Mexico and Agbami offshore Nigeria; first oil expected from both projects in 2008
- Realized first production from projects in Angola, Azerbaijan, Trinidad and Tobago, and the U.K. North Sea

WORLD-CLASS RESERVOIR MANAGEMENT

Chevron is a recognized leader in reservoir management, a process that helps us maximize recovery from our crude oil and natural gas assets. Our steam-flood technology has long been used to enhance production from older fields in California and Indonesia and is now being tested in the Partitioned Neutral Zone (right) between Kuwait and Saudi Arabia.



"CHEVRON PIONEERED THE REFINING OF HEAVY CRUDE OIL. NOW WE'RE INTEGRATING THAT EXPERTISE INTO OUR UPSTREAM OPERATIONS TO DEVELOP SOME OF THE MOST CHALLENGING CRUDES OF ALL – EXTRA-HEAVY OIL AND OIL SANDS. WITH OUR REFINING TECHNOLOGY, WE CAN TURN EVEN THE HEAVIEST OILS INTO GASOLINE AND OTHER HIGH-DEMAND PRODUCTS FOR OUR CUSTOMERS."

ASHOK KRISHNA
GENERAL MANAGER
TECHNOLOGY
DOWNSTREAM



Unconventional energy

Unconventional hydrocarbons – extra-heavy oil, oil sands and oil shale – account for the majority of the world's existing hydrocarbon resources. They are lower in value than conventional crude oils because they are difficult and costly to produce and refine. Over the past 50 years, Chevron has built a broad capability in refining heavy oil and converting it, economically and efficiently, into light, high-value products. Now we are integrating our downstream refining technologies into our upstream operations to develop extra-heavy oil and oil sands, and we are working with others to advance technology to unlock the potential of oil shale.

< TURNING HEAVY OIL INTO LIGHT PRODUCTS (PHOTO LEFT): Chevron's Pascagoula, Mississippi, refinery can process a full slate of crude oils, turning even the heaviest, asphaltlike crude oils into gasoline and other light, high-value products. Integrated oil companies, such as Chevron, that can access extra-heavy crudes and economically refine them into high-demand products have a competitive advantage in today's marketplace.

2006 MILESTONES

- Approved a net additional \$2 billion investment to expand oil sands mining and upgrading facilities for Canada's Athabasca oil sands; acquired new leases in the area
- Established a partnership with the Los Alamos National Laboratory in New Mexico to develop an environmentally responsible and commercially viable process to recover shale oil "in situ," or in place underground

THE POWER OF GEOTHERMAL

Chevron is the world's largest private producer of geothermal energy. We are capturing steam produced from subterranean volcanic activity to help meet the growing electricity needs of Indonesia and the Philippines. A renewable energy source, geothermal is clean, reliable and economic.



Emerging energy

Chevron is making strategic investments in promising new ways to produce transportation fuels. Through our joint venture with Sasol, the South African-based leader in gas-conversion technology, we plan to produce ultraclean diesel fuel from natural gas. High-quality gas-to-liquids fuels could help diversify our downstream fuel supplies. In 2006, we also formed a new business unit to develop ways to accelerate the commercial production of biofuels from a number of renewable feedstock sources, including those based on advanced cellulosic technology. We have long been involved in developing renewable energy and continue our strategy to evaluate and capture profitable positions in renewable technologies and businesses.

> ULTRACLEAN FUELS FROM NATURAL GAS (PHOTO RIGHT): Chevron and Nigeria's national oil company are constructing a 34,000-barrel-per-day gas-to-liquids (GTL) plant in Nigeria to produce ultraclean diesel fuel like that shown on the opposite page. The plant is expected to be in operation by the end of the decade with Europe as the likely target market for the diesel. The company also is pursuing GTL opportunities in other countries.

2006 MILESTONES

- Established research alliances to advance the development of renewable transportation fuels
- Joined a study to demonstrate the performance of E85, a blend of 85 percent ethanol and 15 percent gasoline
- Installed California's first megawatt-class hydrogen fuel cell cogeneration plant
- Developed cogeneration and biomass facilities for a municipal water pollution control plant that generates electricity from organic matter

RENEWABLE BIODIESEL

Alicia Boutan, vice president of Business Development for Chevron Technology Ventures, helped negotiate our investment in a new facility in Galveston, Texas, that will turn renewable feedstocks into biodiesel. The facility will have the potential to produce 100 million gallons per year of this clean-burning fuel, which represents about one-half of current U.S. production of biodiesel. Completion is expected in 2007.



"CHEVRON HAS VAST NATURAL GAS RESOURCES. OUR GAS-TO-LIQUIDS BUSINESS COMPLEMENTS THE COMPANY'S LIQUEFIED NATURAL GAS AND PIPELINE BUSINESSES BY PROVIDING A UNIQUE OPPORTUNITY TO CONVERT NATURAL GAS INTO ULTRACLEAN LIQUID TRANSPORTATION FUELS TO MEET GROWING DEMAND."

CHI-WEN HUNG

VICE PRESIDENT
GAS-TO-LIQUIDS DEVELOPMENTS
GLOBAL GAS



Efficient energy

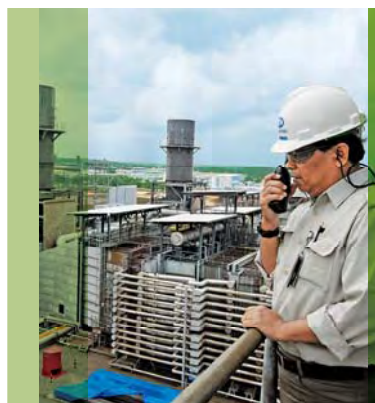
We believe energy efficiency and conservation are the most economic sources of “new” energy. As a large consumer of energy, we continually look for ways to drive greater efficiencies throughout our operations. Since 1992, the year we began tracking, we have increased the energy efficiency of our global operations by 27 percent and lowered our annual energy costs by approximately \$2 billion. In addition to our internal efforts, we provide energy efficiency services to external customers. Over the past three years, Chevron Energy Solutions has helped its clients reduce energy use at their facilities by nearly 30 percent on average.

> SOLAR-POWERED MAIL (PHOTO RIGHT): At a U.S. Postal Service facility in Oakland, California, solar panels span a rooftop area nearly the size of two football fields. Engineered and installed by Chevron Energy Solutions, it is one of the largest rooftop solar power installations in the United States. In combination with other energy efficiency improvements, the system is expected to reduce the postal facility's power purchases by more than one-third.

2006 MILESTONES

- Improved refinery reliability and capacity utilization rate, which contributed significantly to the overall increase in energy efficiency for the year
- Conducted full audits at 12 facilities and partial audits at 15 facilities to identify efficiency gaps and to ensure the application of best practices
- Realized an energy efficiency gain of 7 percent from a major clean-fuels project at the Kurnell, Australia, affiliate refinery

COGENERATION – EFFICIENT AND PRODUCTIVE



A 300-megawatt cogeneration plant is being used to power a steamflood project at Chevron's giant Duri Field in Indonesia. Cogeneration is a fuel-efficient and environmentally friendly process to produce steam and electric power simultaneously. Heat from gas exhaust, a byproduct of electricity generation, is used to create steam, which aids the flow of oil when it is injected into the reservoir.



"CHEVRON IS DEVELOPING INNOVATIVE SOLUTIONS TO HELP OUR CUSTOMERS USE ENERGY MORE EFFICIENTLY AND TO HELP THEM GENERATE POWER FROM RENEWABLE SOURCES SUCH AS SOLAR, WIND AND BIOMASS. WE BELIEVE THERE'S HUGE POTENTIAL FOR ENERGY EFFICIENCY AND THE ECONOMIC AND ENVIRONMENTAL BENEFITS THAT IT PROVIDES."

JIM DAVIS

PRESIDENT
CHEVRON ENERGY SOLUTIONS



Human energy

The successful development of our energy portfolio requires tremendous resources – none more important than human energy. At Chevron, a spirit of ingenuity, collaboration and commitment drives our business every day and helps us create innovative solutions to the most demanding problems. Our human energy is embodied in many ways – from the enterprise approach that Chevron employees take to solve business challenges, to the partnerships we form with other businesses, local communities and governments. Because human energy is infinite, so is the potential to meet the world's demand for safe, reliable energy.

> HELPING STUDENTS LEARN (PHOTO RIGHT): In Venezuela, Chevron and the Discovery Channel Global Education Partnership have established 15 learning centers in three states. The centers provide DVDs and other educational media and materials to more than 11,000 rural or underprivileged students. Shown here are students at Our Lady of the Sacred Heart in Maracaibo, site of one of the centers. They are (left to right) Zulimar Piña, Jackzury Rosales, Angel D. Vilchez, Yesica Morán and Aldrin Fajardo. Similar learning centers have been established in Angola and South Africa.

2006 MILESTONES

- Launched an \$18 million Energy for Learning initiative to aid public school students in Louisiana and Mississippi affected by Hurricanes Rita and Katrina
- Brought together leaders of nongovernmental organizations from around the world for business and financial management training
- Began to establish technology centers in Australia and Scotland to accelerate the deployment of technical innovation across the enterprise; other centers are in California and Texas

DEVELOPING HUMAN ENERGY



Our goal is to be recognized as the employer of choice. We encourage a collaborative environment and have programs in place to attract, develop and retain top talent. Our long queue of capital projects has increased staffing and development opportunities dramatically. In response, we have developed programs to facilitate the transition of new employees into Chevron and acquaint them with our processes, procedures and values.



"WE TRY TO MAKE THE COMMUNITIES WHERE WE OPERATE BETTER PLACES TO LIVE AND WORK – WHETHER IT'S BY TRAINING LOCAL EMPLOYEES, CONTRIBUTING TO A REGION'S SUSTAINABLE ECONOMIC DEVELOPMENT, USING LOCAL SUPPLIERS OR INVESTING IN BETTER EDUCATION. OUR LONG-TERM SUCCESS IS TIED DIRECTLY TO THE HEALTH OF THE COMMUNITIES WHERE WE DO BUSINESS."

ALI MOSHIRI
MANAGING DIRECTOR
LATIN AMERICA
UPSTREAM

Chevron perspectives

LEFT TO RIGHT:

RAJESH PAULOSE
Global Product Line
Manager - Biofuels
and Hydrogen, Global
Marketing

LYNN CHOU
General Manager, Global
Technology and Strategy,
Chevron Information
Technology Company

ROSS HILL
Senior Geophysical
Consultant/Chevron
Fellow, Chevron Energy
Technology Company

ROBERT LESTZ
Oil Shale Technology
Manager, Chevron
Energy Technology
Company



Technology is the foundation for delivering today's business performance and meeting tomorrow's growing energy demand. Managing the energy portfolio will require a combination of accelerated technology development and ingenuity in its application. Here are excerpts from a roundtable discussion among four leading Chevron technologists who are helping expand the boundaries of energy – from conventional oil and natural gas to the resources of the future.

RAJESH :: Demand for biofuels is growing, and integrated companies like Chevron are uniquely positioned to take advantage of this growth. We have the full-scale capabilities to develop biofuels to commercial scale and distribute them across our retail network. And we have the experience of doing so reliably and safely. For me, personally, to help make this new technology part of Chevron's long-term energy portfolio is very exciting.

What we don't want to do today is pick a single solution for biofuels, because no one knows what tomorrow is going to bring. So we have multiple pathways that we're trying to develop down the road. No matter which one pans out, we'll be able to succeed in the marketplace.

Innovation and ingenuity have always been part of the Chevron culture. I don't believe that ingenuity is a one-person show. It's all about people talking to people, teams working with teams and collectively coming up with those innovative ideas that add value to our business.

LYNN :: Chevron deals with huge amounts of information. Our Information Technology (IT) group serves more than 63,000 network end-users and more than 7,600 servers around the world. We process more than 1 million email transactions a day and about 140 retail transactions a second. Managing information on this scale requires efficiency and integration so that everyone in the enterprise can be more productive.

We apply IT resources to help us function better as an integrated company. We provide the processes and the tools for people to collaborate more effectively and to transfer knowledge and best practices across divisional or geographic boundaries. IT can stimulate business process changes and help unleash the creative potential of Chevron's people.

We also leverage IT to benefit our customers. We created a Web site for our Global Lubricants group that allows its customers and partners, in just a few clicks, to see our products, pricing, safety and training materials, and other information. It makes doing business with Chevron a lot easier.

ROSS :: Chevron's seismic imaging technology is allowing us to see beneath the earth more clearly and accurately than ever before. Recorded echoes produce huge data volumes, which we process and analyze with some of the world's most powerful computing systems to form a three-dimensional image of the earth. The better we can image challenging environments, the fewer wells we have to drill to produce the same reservoir.

These continuing advances help us find more oil and gas than in the past, especially in frontier areas. For example, Chevron has built a leading capability in imaging the shape of reservoirs beneath massive layers of salt that cover large potential resources in ultradeep water in the U.S. Gulf of Mexico.

Today, we use seismic imaging to help us locate and extract resources. But we can easily imagine how seismic imaging can be applied to carbon sequestration, where we'll want to do the opposite – put greenhouse gases back into the reservoir. Seismic imaging could well play a big role in enabling us to do that. That type of potential innovation is tremendously exciting.

ROBERT :: There are vast reserves of oil shale in the western United States. We are exploring technology – with the help of partners like the Los Alamos National Laboratory – to turn this resource into commercial products in a radically new way. If we can recover the resource underground, it will solve many of the environmental issues associated with the production of oil shale in the past.

This is a new technology platform for resource development that in some ways is similar to the major technological shifts derived from the U.S. space program in the 1960s. This is especially true in terms of the potential scale of the business and resource impact it could have for the United States. The applications of this technology to recover oil shale could have value that extends across the corporation and the industry.

Chevron's philosophy on technology is very clear. We're not looking at repeating the same old technology, because the same old technology gets you what you had in the past. We're looking at developing new processes that will produce new results to unlock the potential of this world-class resource.

Operating highlights

Chevron is one of the world's leading integrated energy companies. We have approximately 56,000 employees, and our subsidiaries conduct business in more than 180 countries. We operate across the entire energy spectrum – producing and transporting crude oil and natural gas; refining, marketing and distributing fuels and other energy products and services; manufacturing and selling petrochemical products; generating power; and developing and commercializing the energy resources of the future, including biofuels and other renewables.

Upstream

UPSTREAM AT A GLANCE

At the end of 2006, worldwide net proved crude oil and natural gas reserves for consolidated operations were 8.6 billion barrels of oil-equivalent and for affiliated operations were 3 billion barrels. Production averaged 2.67 net million barrels of oil-equivalent per day, including volumes produced from oil sands and production under an operating service agreement. Major producing areas include Angola, Australia, Indonesia, Kazakhstan, Nigeria, the Partitioned Neutral Zone, Thailand, the United Kingdom, the United States and Venezuela. Major exploration areas include western Africa, Australia, Brazil, Canada, the Gulf of Thailand, the Norwegian Barents Sea, the international waters between Trinidad and Tobago and Venezuela, the U.K. Atlantic Margin, and the U.S. Gulf of Mexico.

Upstream explores for and produces crude oil and natural gas. Our strategy is to grow profitably in core areas and build new legacy positions. We have major assets in the world's most prolific regions, and we are generally among the top producers wherever we operate. We currently have more than 35 major capital projects in various stages of development, each representing an investment of \$500 million or more and each located in areas of great resource potential. We also have one of the industry's leading exploration records. In 2006, we had our fifth year of successful exploration results and added more than 1 billion barrels of crude oil and natural gas resources. One leading energy consulting firm said Chevron has one of the strongest exploration portfolios in its peer group, with proven experience in pushing the boundaries of known technology.

STRONG PERFORMANCE Upstream achieved a number of milestones in 2006. During the year, initial production began from Angola's deepwater Benguela and Lobito fields, part of the Benguela Belize-Lobito Tomboco (BBLT) development. By



utilizing the BBLT infrastructure, production also began from the nearby Landana North reservoir, part of the Tombua-Landana development. We also realized first production from fields in Azerbaijan, Trinidad and Tobago, and the U.K. North Sea. In Kazakhstan, where the Tengizchevroil joint venture is the largest private producer, significant progress was made on the Sour Gas Injection/Second Generation Plant project. Scheduled for startup in 2007, the integrated projects are expected to increase crude oil production capacity from the Tengiz and Korolev fields from the current 300,000 barrels per day to between 460,000 and 550,000 barrels per

Upstream

day. During the year, we also began construction on the Tahiti development in the deepwater U.S. Gulf of Mexico and completed key components of a floating production, storage and offloading vessel for the Agbami development in Nigeria's deep water. In Canada, we approved a net additional \$2 billion investment in the Athabasca Oil Sands Project, which will increase design capacity from 100,000 barrels of bitumen per day to more than 255,000 barrels per day. Chevron has a 20 percent interest.

In 2006, we committed to develop other major discoveries. Offshore Brazil, we plan to develop the Frade Field, our first oil field development in that country. Frade is expected to begin producing in early 2009. Two years after startup it is expected to reach a maximum production rate of 90,000 barrels of oil-equivalent per day. We also announced plans to develop the Great White, Silvertip and Tobago fields in the deepwater U.S. Gulf of Mexico.

EXPLORATION SUCCESSES Chevron has one of the most robust and successful exploration programs in the industry. The foundation for our string

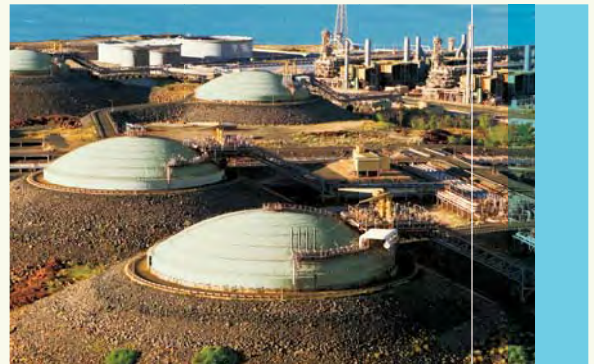


of discoveries is the use of proprietary technology that helps us map deepwater reservoirs with unprecedented clarity. In 2006, we announced significant crude oil discoveries in deepwater Nigeria and the U.S. Gulf of Mexico. We also made two major natural gas discoveries offshore Western Australia, both within the giant Greater Gorgon Area, which we plan to develop.

During the year, we acquired new exploration acreage in Canada, in the Norwegian Barents Sea, in the deepwater U.S. Gulf of Mexico and offshore Western Australia. We also increased our acreage in Canada's Athabasca oil sands region.

To help maintain our leading position in deepwater exploration and production, we awarded a contract for the construction of a state-of-the-art drill ship that is expected to have the most advanced drilling capabilities in the offshore drilling industry. Expected to be delivered in 2009, it will be dedicated exclusively to Chevron for a five-year period.

GLOBAL GAS Global Gas is focused on commercializing our large equity natural gas resource base while growing a high-impact business. Chevron operates in some of the world's leading natural gas basins and uses state-of-the-art technologies to develop the full spectrum of natural gas – from conventional pipeline gas to liquefied natural gas (LNG) to gas-to-liquids (GTL). We hold the largest natural gas resource position in Australia and have other significant natural gas holdings in western Africa, Kazakhstan, Latin America, North America and Thailand. Global Gas is highly integrated and brings together the key businesses involved in every aspect of developing natural gas – production, liquefaction, shipping, regasification, pipelines, marketing and trading, power generation, and GTL technology. Our strong integration enables us to benefit across the entire natural gas value chain.



We are moving forward to commercialize our vast natural gas holdings from the giant Greater Gorgon Area, offshore Western Australia. We plan to develop LNG projects for Gorgon, as well as projects in Angola and Nigeria, and we are evaluating opportunities in Venezuela. During the year, we delivered the first natural gas from a field offshore Trinidad and Tobago to an LNG processing facility in Point Fortin, Trinidad. The North West Shelf Venture (NWSV), offshore Western Australia, delivered China's first imported shipment of LNG under a 25-year agreement. A fifth LNG train is currently under construction to accommodate increased production from the NWSV. Chevron is an equal one-sixth partner in the venture.

Our GTL joint venture, Sasol Chevron, is providing management, operating and technical services for a 34,000-barrel-per-day GTL plant under construction in Nigeria. The company also is pursuing GTL opportunities in other countries.

- > Top: North West Shelf Venture, Western Australia; bottom: Sour Gas Injection/Second Generation Plant project, Kazakhstan.
- > Opposite page: Well Engineer Bobby Scott, Kern River Field, California.

Downstream

DOWNSTREAM AT A GLANCE

In 2006, Chevron processed approximately 2 million barrels of crude oil per day and averaged approximately 3.6 million barrels per day of refined products sales worldwide. Major areas of operations are in Asia, in sub-Saharan Africa, on the U.S. Gulf Coast extending into Latin America and on the U.S. West Coast. We hold interests in 20 fuel refineries and have a marketing presence in approximately 175 countries. We market under the Chevron, Texaco and Caltex motor fuel brands. Products are sold through a network of approximately 25,800 retail stations, including those of affiliate companies.

Chevron's downstream strategy is to improve base business returns and selectively grow with a focus on integrated value creation. Our downstream operations comprise refining, fuels and lubricants marketing, supply and trading, and transportation. Our refining operations are strategically located to serve fast-growing markets in North America and Asia. Our three motor fuel brands are among the industry's most respected.

REFINING In 2006, we completed an expansion at our Pascagoula, Mississippi, refinery to increase production of gasoline and other light products, and began upgrading an affiliate refinery in South Korea to process heavy crude oils. We also purchased a

5 percent interest in Reliance Petroleum Limited, which will own and operate a 580,000-barrel-per-day crude capacity refinery being built in India. It is expected to begin operating in late 2008. We have the opportunity to increase our ownership to 29 percent. Our refinery utilization rate was 90 percent in 2006, an improvement of 4 percent from 2005 and our strongest rate since 1999. In the United States, our refineries operated close to their crude oil unit design capacity.

MARKETING In the United States, the Chevron and Texaco brands have been ranked the two most powerful brands by the Oil Price Information Service, the leading source for petroleum pricing and news information. In 2006, we expanded our U.S. Texaco marketing network to more than 2,100 sites and continued a phased introduction of our gasoline additive, Techron, to our international Texaco and Caltex brands. We also continued to divest nonstrategic marketing assets, exiting the fuels marketing business in Ecuador, Paraguay and Scandinavia.

OTHER Chevron is a leading global marketer of finished lubricants. In 2006, we began an expansion of base-oil production at the Richmond, California, refinery and at the Yeosu, South Korea, refinery. Also during the year, the company's supply and trading organization expanded crude oil selection options for our refining system and created a new organization to manage our growing supplies of natural gas liquids and liquefied petroleum gas.



- > Above, left to right: Caltex service station, Singapore; Singapore Refining Company.
- > Opposite page, left to right: Fuel cell, Santa Rita Jail, Alameda County, California; Laboratory Technician Frederic Richer, Chevron Oronite, Gonfreville, France.

Chevron's three technology companies – Energy Technology, Technology Ventures and Information Technology – support the strategies of our core businesses and are engaged in developing technology to enable our most promising future opportunities. Two new technology centers are being established in Australia and Scotland to complement existing centers in California and Texas. The centers provide research, development and technical support to our global businesses.

Technology

and other businesses

In 2006, we formed a biofuels business unit to advance technology and pursue commercial opportunities in ethanol and biodiesel fuels in the United States. As part of this effort, we acquired an interest in a biodiesel facility being built in Galveston, Texas, and we forged two research alliances – with the Georgia Institute of Technology and the University of California, Davis – to develop advanced cellulosic biofuels. We also established a research alliance with the U.S. Department of Energy's National Renewable Energy Laboratory to advance the development of renewable transportation fuels. Another collaboration with General Motors, the state of California and Pacific Ethanol will study in depth the performance of E85, a blend of 85 percent ethanol and 15 percent gasoline, as a clean, high-performing fuel.



OTHER BUSINESSES Chevron is engaged in a number of other businesses across the energy value chain. Our 50-50 joint venture Chevron Phillips Chemical Company LLC is one of the world's leading manufacturers of petrochemicals. Chevron Oronite markets more than 500 performance-enhancing products and supplies one-fourth of the world's fuel and lubricant additives. Global Power Generation develops and markets commercial power projects worldwide. Chevron Energy Solutions delivers energy-efficiency and power-system solutions to external and internal clients (see Page 12). For more information about the businesses of Chevron, visit our Web site: www.chevron.com.

OPERATIONAL EXCELLENCE

To help us operate at world-class levels, we have systematic operational excellence processes integrated into every aspect of our business. Our Operational Excellence Management System helps us protect people and the environment and maintain our reputation as a reliable and efficient energy provider.

Safety is our highest priority. For the fifth consecutive year, we improved our safety performance and reduced the rate of injuries severe enough to require days away from work by 25 percent compared with 2005. Our safety performance is among the top in the industry, and we continue to move toward world-class performance.

Our environmental performance also continued to improve. In 2006, we had 5 percent fewer oil spills, and volumes were significantly lower than in previous years. During the year, we also continued to generate greater energy efficiencies in our operations (see Page 12).

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 and production*.

Biofuel Any fuel that is derived from biomass – recently living organisms or their metabolic byproducts – from sources such as farming, forestry, and biodegradable industrial and municipal waste. See *renewables*.

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

Development Drilling, construction and related activities following discovery that are necessary to begin production and transportation of crude oil and natural gas.

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.

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

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 energy 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 crude oil. Approximately 6,000 cubic feet of natural gas is equivalent to one barrel of crude 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 oil*.

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 both royalties paid to landowners and a government's agreed-upon share of production under a *production-sharing contract*. *Net production* is gross production minus both royalties paid to landowners and a government's agreed-upon share of production under a *production-sharing contract*. *Oil-equivalent production* is the sum of the barrels of liquids and the oil-equivalent barrels of natural gas produced. See *barrels of oil-equivalent* and *oil-equivalent gas*.

Production-sharing contract A contractual agreement between a company and a government whereby the company bears all exploration, development and production costs in return for an agreed-upon share of production.

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, biofuels, 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. *Oil-equivalent reserves* are the sum of the liquids reserves and the oil-equivalent gas reserves. See *barrels of oil-equivalent* and *oil-equivalent gas*.

The rules of the United States Securities and Exchange Commission (SEC) permit oil and gas companies to disclose in their filings with the SEC only proved reserves. Certain terms, such as "probable" or "possible" reserves, "potentially recoverable" volumes, or "resources," among others, may be used to describe certain oil and gas properties in sections of this document that are not filed with the SEC. We use these other terms, which are not approved for use in SEC filings, because they are commonly used in the industry, are measures considered by management to be important in making capital investment and operating decisions, and provide some indication to our stockholders of the potential ultimate recovery of oil and gas from properties in which we have an interest. In that regard, *potentially recoverable* volumes are those that can be produced using all known primary and enhanced recovery methods.

Synthetic crude oil A marketable and transportable hydrocarbon liquid, resembling crude oil, that is produced by upgrading highly viscous or solid hydrocarbons, such as extra-heavy crude oil or *oil sands*.

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.

Cumulative effect of change in accounting principle The effect on net income in the period of change of a retroactive calculation and application of a new accounting principle.

Goodwill The excess of the purchase price of an acquired entity over the total fair value assigned to assets acquired and liabilities assumed.

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

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

Return on capital employed (ROCE) Ratio 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 (TSR) The return to stockholders as measured by stock price appreciation and reinvested dividends for a period of time.

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**CAUTIONARY STATEMENT 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 Chevron Corporation contains forward-looking statements relating to Chevron'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," "schedules," "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, Chevron undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are unknown or unexpected problems in the resumption of operations affected by Hurricanes

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OTHER INFORMATION

The company has submitted to the New York Stock Exchange a certificate of the Chief Executive Officer of the company certifying that he is not aware of any violation by the company of New York Stock Exchange corporate governance listing standards. The 302 certifications have been filed in the Form 10-K.

Katrina and Rita and other severe weather in the Gulf of Mexico; 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; the ability to successfully integrate the operations of Chevron and Unocal Corporation; the inability or failure of the company's joint-venture partners to fund their share of operations and development activities; the potential failure to achieve expected net production from existing and future crude oil and natural gas development projects; potential delays in the development, construction or start-up of planned projects; the potential disruption or interruption of the company's net production or manufacturing facilities due to war, accidents, political events, civil unrest or severe weather; the potential liability for remedial actions under existing or future environmental regulations and litigation; significant investment or product changes under existing or future environmental regulations and litigation (including, particularly, regulations and litigation dealing with gasoline composition and characteristics); the potential liability resulting from pending or future litigation; the company's acquisition or disposition of assets; 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 in this report could also have material adverse effects on forward-looking statements.

KEY FINANCIAL RESULTS

<i>Millions of dollars, except per-share amounts</i>	2006	2005	2004
Net Income	\$ 17,138	\$ 14,099	\$ 13,328
Per Share Amounts:			
Net Income – Basic	\$ 7.84	\$ 6.58	\$ 6.30
– Diluted	\$ 7.80	\$ 6.54	\$ 6.28
Dividends	\$ 2.01	\$ 1.75	\$ 1.53
Sales and Other			
Operating Revenues	\$ 204,892	\$ 193,641	\$ 150,865
Return on:			
Average Capital Employed	22.6%	21.9%	25.8%
Average Stockholders' Equity	26.0%	26.1%	32.7%

INCOME FROM CONTINUING OPERATIONS BY MAJOR OPERATING AREA

<i>Millions of dollars</i>	2006	2005	2004
Income From Continuing Operations			
Upstream – Exploration and Production			
United States	\$ 4,270	\$ 4,168	\$ 3,868
International	8,872	7,556	5,622
Total Upstream	13,142	11,724	9,490
Downstream – Refining, Marketing and Transportation			
United States	1,938	980	1,261
International	2,035	1,786	1,989
Total Downstream	3,973	2,766	3,250
Chemicals	539	298	314
All Other	(516)	(689)	(20)
Income From Continuing Operations	\$ 17,138	\$ 14,099	\$ 13,034
Income From Discontinued Operations – Upstream	–	–	294
Net Income*	\$ 17,138	\$ 14,099	\$ 13,328
*Includes Foreign Currency Effects:	\$ (219)	\$ (61)	\$ (81)

Refer to the “Results of Operations” section beginning on page 30 for a detailed discussion of financial results by major operating area for the three years ending December 31, 2006.

BUSINESS ENVIRONMENT AND OUTLOOK

Chevron's current and future earnings depend largely on the profitability of its upstream (exploration and production) and downstream (refining, marketing and transportation) business segments. The single biggest factor that affects the results of operations for both segments is movement in the price of crude oil. In the downstream business, crude oil is the largest cost component of refined products. The overall trend in earnings is typically less affected by results from the company's chemicals business and other activities and investments. Earnings for the company in any period may also be influenced by events or transactions that are infrequent and/or unusual in nature. Chevron and the oil and gas industry at large are currently experiencing an increase in certain costs that exceeds the general trend of inflation in many areas of the world. This increase in costs is affecting the company's

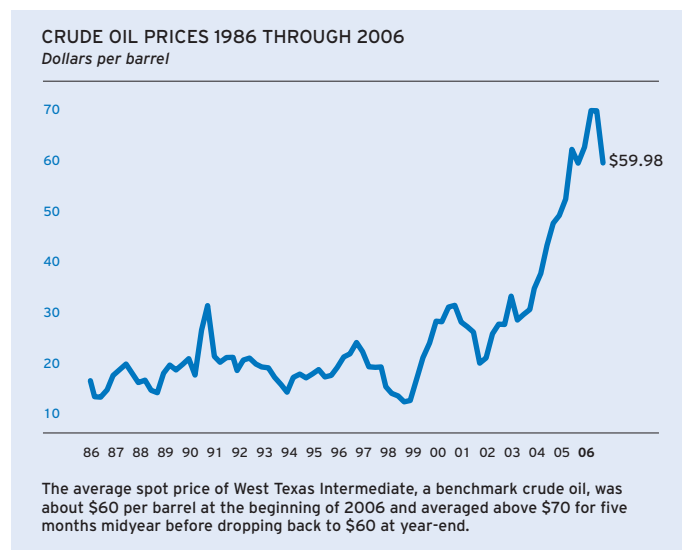
operating expenses for all business segments and capital expenditures, particularly for the upstream business.

To sustain its long-term competitive position in the upstream business, the company must develop and replenish an inventory of projects that offer adequate financial returns for the investment required. Identifying promising areas for exploration, acquiring the necessary rights to explore for and to produce crude oil and natural gas, drilling successfully, and handling the many technical and operational details in a safe and cost-effective manner are all important factors in this effort. Projects often require long lead times and large capital commitments. Changes in economic, legal or political circumstances can have significant effects on the profitability of a project over its expected life. In the current environment of higher commodity prices, certain governments have sought to renegotiate contracts or impose additional costs on the company. Other governments may attempt to do so in the future. The company will continue to monitor these developments, take them into account in evaluating future investment opportunities, and otherwise seek to mitigate any risks to the company's current operations or future prospects. In late February 2007, the President of Venezuela issued a decree announcing the government's intention for the state-owned company, *Petróleos de Venezuela S.A.*, to increase its ownership later this year in all Orinoco Heavy Oil Associations, including Chevron's 30 percent-owned Hamaca project, to a minimum of 60 percent. The impact on Chevron from such an action is uncertain but is not expected to have a material effect on the company's results of operations, consolidated financial position or liquidity.

The company also continually evaluates opportunities to dispose of assets that are not key to providing sufficient long-term value, or to acquire assets or operations complementary to its asset base to help augment the company's growth. During the first quarter 2007, the company authorized the sale of its 31 percent ownership interest in the Nerefco Refinery and the associated TEAM Terminal in the Netherlands. The transaction is subject to signing of the sales agreement and obtaining necessary regulatory approvals. The company expects to record a gain upon close of the sale. In early 2007, the company was also in discussions regarding the possible sale of its fuels marketing operations in the Netherlands, Belgium and Luxembourg. Neither the refining nor marketing assets were classified as held-for-sale as of December 31, 2006, in accordance with the held-for-sale criteria of Financial Accounting Standards Board (FASB) Statement No. 144, *Impairment or Disposal of Long-Lived Assets*. Other asset dispositions and restructurings may occur in future periods and could result in significant gains or losses.

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

Upstream Earnings for the upstream segment are closely aligned with industry price levels for crude oil and natural gas. Crude oil and natural gas prices are subject to 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 damage and disruptions, competing fuel prices, and regional supply interruptions that may be caused



by military conflicts, civil unrest or political uncertainty. Moreover, any of these factors could also inhibit the company's production capacity in an affected region. The company monitors developments closely in the countries in which it operates and holds investments, and attempts to manage risks in operating its facilities and business.

Price levels for capital and exploratory costs and operating expenses associated with the efficient production of crude oil and natural gas can also be subject to external factors beyond the company's control. External factors include not only the general level of inflation, but also prices charged by the industry's product and service providers, which can be affected by the volatility of the industry's own supply and demand conditions for such products and services. The oil and gas industry worldwide experienced significant price increases for these items during 2005 and 2006, and an upward trend in prices may continue into 2007. Capital and exploratory expenditures and operating expenses also can be affected by uninsured damages to production facilities caused by severe weather or civil unrest.

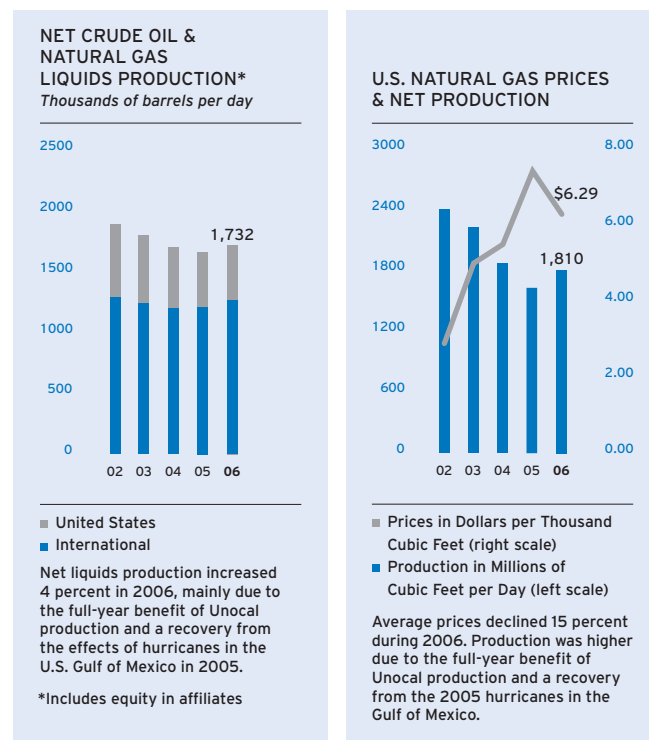
Industry price levels for crude oil generally increased in the first half of 2006 and declined in the second half. Prices at the end of 2006 were slightly lower than at the beginning of the year. The spot price for West Texas Intermediate (WTI) crude oil, a benchmark crude oil, averaged \$66 per barrel in 2006, an increase of approximately \$9 per barrel from the 2005 average price. The rise in crude oil prices between years reflected, among other things, increasing demand in growing economies, the heightened level of geopolitical uncertainty in some areas of the world and supply concerns in other key

producing regions. For early 2007 into late February, the WTI spot price averaged about \$56 per barrel.

As was the case in 2005, a wide differential in prices existed in 2006 between high-quality, light-sweet crude oils (such as the U.S. benchmark WTI) and heavier types of crude. The price for the heavier crudes has been dampened because of ample supply and lower relative demand due to the limited number of refineries that are able to process this lower-quality feedstock into light products (i.e., motor gasoline, jet fuel, aviation gasoline and diesel fuel). The price for higher-quality, light-sweet crude oil has remained high, as the demand for light products, which can be more easily manufactured by refineries from light-sweet crude oil, has been strong worldwide. Chevron produces heavy crude oil in California, Chad, Indonesia, the Partitioned Neutral Zone between Saudi Arabia and Kuwait, Venezuela and in certain fields in Angola, China and the United Kingdom North Sea. (Refer to page 35 for the company's average U.S. and international crude oil prices.)

In contrast to price movements in the global market for crude oil, price changes for natural gas are more closely aligned with regional supply and demand conditions. In the United States during 2006, benchmark prices at Henry Hub averaged about \$6.50 per thousand cubic feet (MCF), compared with about \$8 in 2005. For early 2007 into late February, prices averaged about \$7 per MCF. Fluctuations in the price for natural gas in the United States are closely associated with the volumes produced in North America and the inventory in underground storage relative to customer demand. Natural gas prices in the United States are also typically higher during the winter period when demand for heating is greatest.

In contrast to the United States, certain other regions of the world in which the company operates have different supply, demand and regulatory circumstances, typically resulting



in significantly lower average sales prices for the company's production of natural gas. (Refer to page 35 for the company's average natural gas prices for the United States and international regions.) Additionally, excess supply conditions that exist in certain parts of the world cannot easily serve to mitigate the relatively high-price conditions in the United States and other markets because of the lack of infrastructure to transport and receive liquefied natural gas.

To help address this regional imbalance between supply and demand for natural gas, Chevron is planning increased investments in long-term projects in areas of excess supply to install infrastructure to produce and liquefy natural gas for transport by tanker, along with investments and commitments to regasify the product in markets where demand is strong and supplies are not as plentiful. Due to the significance of the overall investment in these long-term projects, the natural gas sales prices in the areas of excess supply (before the natural gas is transferred to a company-owned or third-party processing facility) are expected to remain well below sales prices for natural gas that is produced much nearer to areas of high demand and can be transported in existing natural gas pipeline networks (as in the United States).

Besides the impact of the fluctuation in price for crude oil and natural gas, the longer-term trend in earnings for the upstream segment is also a function of other factors, including the company's ability to find or acquire and efficiently produce crude oil and natural gas, changes in fiscal terms, and the cost of goods and services.

Chevron's worldwide net oil-equivalent production in 2006, including volumes produced from oil sands and production under an operating service agreement, averaged 2.67 million barrels per day, or 6 percent higher than production in 2005. The increase between periods was largely due to volumes associated with the acquisition of Unocal in August 2005. The company estimates that oil-equivalent production in 2007 will average approximately 2.6 million barrels per day. This estimate is subject to many uncertainties, including quotas that may be imposed by OPEC, the price effect on production volumes calculated under cost-recovery and variable-royalty provisions of certain contracts, changes in fiscal terms or restrictions on the scope of company operations, and production disruptions that could be caused by severe weather, local civil unrest and changing geopolitics. Future production levels also are affected by the size and number of economic investment opportunities and, for new large-scale projects, the time lag between initial exploration and the beginning of production. Most of Chevron's upstream investment is currently being made outside the United States. Investments in upstream projects generally are made well in advance of the start of the associated crude oil and natural gas production.

Approximately 24 percent of the company's net oil-equivalent production in 2006 occurred in the OPEC-member countries of Indonesia, Nigeria and Venezuela and in the Partitioned Neutral Zone between Saudi Arabia and Kuwait. In December 2006, OPEC admitted Angola as a new member effective January 1, 2007. Oil-equivalent production for 2006 in Angola represented 6 percent of the company's total. In October 2006, OPEC announced its decision to reduce OPEC-member production quotas by 1.2 million barrels of crude oil per day, or 4.4 percent, from a production level of 27.5 million barrels, effective November 1, 2006. In December 2006, OPEC announced an additional quota reduction of 500,000 barrels of crude oil per day, effective February 1, 2007. OPEC quotas did not significantly affect Chevron's production level in 2006. The impact of quotas on the company's production in 2007 is uncertain.

In October 2006, Chevron's Boscan and LL-652 operating service agreements in Venezuela were converted to Empresas Mixtas (i.e., joint stock contractual structures), with Petr leos de Venezuela S.A., as majority shareholder. Beginning in October, Chevron reported its equity share of the Boscan and LL-652 production, which was approximately 90,000 barrels per day less than what the company previously reported under the operating service agreements. The change to the Empresa Mixta structure did not have a material effect on the company's results of operations, consolidated financial position or liquidity.

At the end of 2005 in certain onshore areas of Nigeria, approximately 30,000 barrels per day of the company's net production capacity remained shut-in following civil unrest and damage to production facilities that occurred in 2003. By the end of 2006, the company had resumed operations in portions of all the affected fields, and more than 20,000 barrels per day of production had been restored. In early 2007, additional production restoration activities continued in the area; however, intermittent civil unrest could adversely impact company operations in the future.

Refer to pages 30 through 32 for additional discussion of the company's upstream operations.

Downstream Earnings for the downstream segment are closely tied to global and regional supply and demand for refined products and the associated effects on industry refining and marketing margins. Other factors include the reliability and efficiency of the company's refining and marketing network, the effectiveness of the crude-oil and product-supply functions, and the economic returns on invested capital. Profitability can also be affected by the volatility of charter expenses for the company's shipping operations, which are driven by the industry's demand for crude oil and product tankers. Other factors that are beyond

the company's control include the general level of inflation and energy costs to operate the company's refinery and distribution network.

The company's core marketing areas are the West Coast of North America, the U.S. Gulf Coast, Latin America, Asia and sub-Saharan Africa. The company operates or has ownership interests in refineries in each of these areas, except Latin America. In 2006, earnings for the segment improved substantially, mainly as the result of higher average margins for refined products and improved operations at the company's refineries.

Industry margins in the future may be volatile and are influenced by changes in the price of crude oil used for refinery feedstock and by changes in the supply and demand for crude oil and refined products. The industry supply and demand balance can be affected by disruptions at refineries resulting from maintenance programs and unplanned outages, including weather-related disruptions; refined-product inventory levels; and geopolitical events.

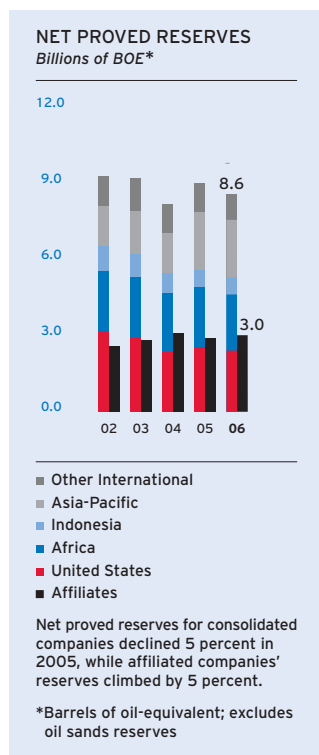
Refer to pages 32 through 33 for additional discussion of the company's downstream operations.

Chemicals Earnings in the petrochemicals business are closely tied to global chemical demand, industry inventory levels and plant capacity utilization. Feedstock and fuel costs, which tend to follow crude oil and natural gas price movements, also influence earnings in this segment.

Refer to page 33 for additional discussion of chemicals earnings.

OPERATING DEVELOPMENTS

Key operating developments and other events during 2006 and early 2007 included:



Upstream

United States In the Gulf of Mexico, the company announced in September 2006 the completion of a successful production test on the 50 percent-owned and operated Jack No. 2 well. The test was a follow-up to the 2004 Jack discovery and was the deepest well test ever accomplished in the Gulf of Mexico.

Also in the Gulf of Mexico, the company announced in October its decision to develop the Great White, Tobago and Silvertip fields via a common producing hub, the Perdido Regional Host, which will have a processing capacity of 130,000 barrels of oil-equivalent per day. First production from the 38 percent-owned Perdido

Regional Host is anticipated by 2010. The company's ownership interests in the fields are Great White – 33 percent, Tobago – 58 percent and Silvertip – 60 percent.

Angola In June 2006, the company produced the first crude oil from the offshore Lobito Field, located in Block 14. Lobito is part of the 31 percent-owned and operated Benguela Belize-Lobito Tomboco (BBLT) development project. As fields and wells are added over the next two years, BBLT's maximum production is expected to reach approximately 200,000 barrels of oil per day. Also in Block 14, the company produced first crude oil in June 2006 from the Landana North reservoir in the 31 percent-owned and operated Tombua-Landana development area. This initial production is tied back to the nearby BBLT production facilities. Tombua-Landana is the company's third deepwater development offshore Angola. Maximum production from the completed Tombua-Landana development is estimated at 100,000 barrels per day by 2010.

In early 2007, the company announced a discovery of crude oil at the 31 percent-owned and operated Lucapa-1 well in deepwater Block 14. The company plans to conduct appraisal drilling and additional geologic and engineering studies to assess the potential resource.

Australia In July 2006, the company discovered natural gas at the Chandon-1 exploration well offshore the northwestern coast in the Greater Gorgon development area. The company's interest in the property is 50 percent.

Also offshore the northwestern coast, the company announced in November 2006 a significant natural gas discovery at its Clio-1 exploration well. The company holds a 67 percent interest in the block where Clio-1 is located. Chevron will be undertaking further work, including a 3-D seismic survey program that started in late 2006, to better determine the potential of the gas find and subsequent development options.

In early 2007, the company was also named operator and awarded a 50 percent interest in exploration acreage in the Greater Gorgon Area. A three-year work program includes geotechnical studies, seismic surveys and drilling of an exploration well.

Azerbaijan The first tanker lifting of crude oil transported through the 9 percent-owned Baku-Tbilisi-Ceyhan (BTC) pipeline occurred in June 2006. The crude is being supplied by the Azerbaijan International Oil Company, in which the company has a 10 percent nonoperated working interest.

Brazil In June 2006, the company announced the decision to develop the 52 percent-owned and operated offshore Frade Field. Initial production is targeted by early 2009, with a maximum annual rate estimated at 90,000 oil-equivalent barrels per day in 2011.

Canada The company acquired heavy oil leases in the Athabasca region of northern Alberta, Canada, in 2005 and 2006. The leases comprise more than 75,000 acres and contain significant volumes that have potential for recovery using Steam Assisted Gravity Drainage technology.

Also in Alberta, the company announced its decision in October 2006 to participate in the expansion of the Athabasca Oil Sands Project (AOSP). The expansion

is expected to add 100,000 barrels per day of mining and upgrading capacity at an estimated total project cost of \$10 billion. Completion of the expansion is planned for 2010, increasing total capacity of the project to approximately 255,000 barrels per day. The company holds a 20 percent nonoperated working interest in AOSP.

Nigeria In May 2006, the company announced the discovery of crude oil at the nonoperated Uge-1 exploration well in the 20 percent-owned offshore Oil Prospecting License 214. Future drilling is contingent primarily on the outcome of ongoing technical studies.

Norway In April 2006, the company was awarded the rights to six blocks in the 19th Norwegian Licensing Round. The 40 percent-owned blocks are located in the Nordkapp East Basin in the Norwegian Barents Sea. A 3-D seismic survey was acquired and is planned to be processed in 2007.

Thailand In early 2006, the company signed two petroleum exploration concessions in the Gulf of Thailand. Chevron has a 71 percent operated interest in one concession, which is in the proximity of the company's Tantawan and Plamuk fields. Initial drilling in the concession is scheduled during 2007. Drilling is projected by 2009 for the other concession, in which Chevron has a 16 percent nonoperated working interest.

United Kingdom In June 2006, the company produced the first crude oil from the 85 percent-owned and operated Area C in the Captain Field. The project reached maximum production of 14,000 barrels of crude oil per day in September 2006.

In early 2007, the company was awarded eight operated exploration blocks and two nonoperated blocks west of Shetland Islands in the 24th United Kingdom Offshore Licensing Round.

Vietnam In April 2006, the company signed a 30-year production-sharing contract with Vietnam Oil and Gas Corporation for Block 122 offshore eastern Vietnam. The company has a 50 percent interest in this block and has undertaken a three-year work program for seismic acquisition and drilling of an exploratory well.

Downstream

United States In December 2006, the company completed the expansion of the Fluid Catalytic Cracking Unit at the company's refinery in Pascagoula, Mississippi, increasing the refinery's gasoline manufacturing capacity by about 10 percent. The company also submitted an environmental permit application for construction of facilities to increase gasoline output by another 15 percent.

India In April 2006, the company acquired a 5 percent interest in Reliance Petroleum Limited, a company formed by Reliance Industries Limited to construct, own and operate a refinery in Jamnagar, India. The new refinery would be the world's sixth largest, designed for a crude oil processing capacity of 580,000 barrels per day. Chevron and Reliance

Industries also signed two memoranda of understanding to jointly pursue other downstream and upstream business opportunities. If discussions pursuant to the memoranda of understanding lead to definitive agreements, Chevron may increase its equity stake in Reliance Petroleum to 29 percent.

Other

Biofuels In May 2006, the company announced that it had completed the acquisition of a 22 percent interest in Galveston Bay Biodiesel L.P., which is building one of the first large-scale biodiesel plants in the United States. The following month, the company entered into a research alliance with the Georgia Institute of Technology to pursue advanced technology aimed at making cellulosic biofuels and hydrogen into transportation fuels. In September, the company announced a research collaboration with the University of California–Davis aimed at converting cellulosic biomass into transportation fuels.

Common Stock Dividends and Stock Repurchase Program

In April 2006, the company increased its quarterly common stock dividend by 15.5 percent to \$0.52 per share. In November, the company completed its second \$5 billion common stock buyback program since 2004 and in December authorized the acquisition of up to \$5 billion of additional shares over a period of up to three years.

RESULTS OF OPERATIONS

Major Operating Areas The following section presents the results of operations for the company's business segments – upstream, downstream and chemicals – as well as for “all other,” which includes mining, power generation businesses, and the various companies and departments that are managed at the corporate level. Income is also presented for the U.S. and international geographic areas of the upstream and downstream business segments. (Refer to Note 8, beginning on page 62, for a discussion of the company's “reportable segments,” as defined in FASB No. 131, *Disclosures About Segments of an Enterprise and Related Information*.) This section should also be read in conjunction with the discussion in “Business Environment and Outlook” on pages 26 through 29.

U.S. Upstream – Exploration and Production

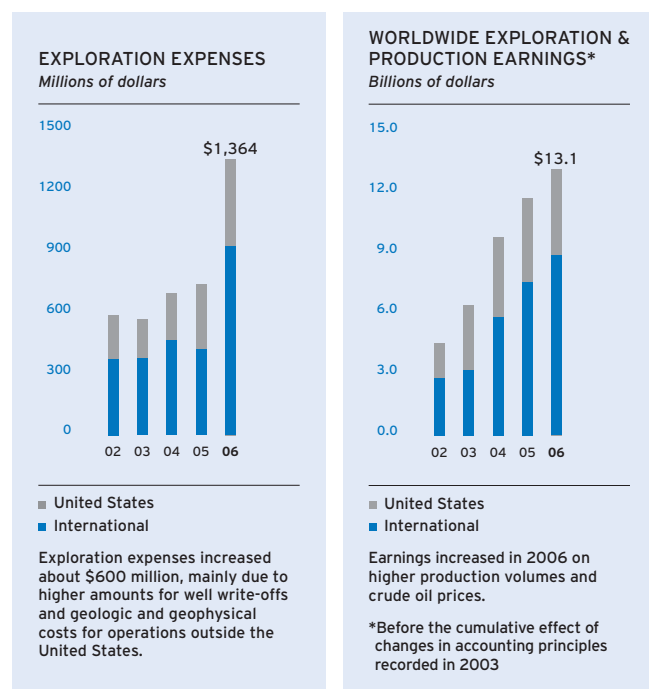
Millions of dollars	2006	2005	2004
Income From Continuing Operations	\$ 4,270	\$ 4,168	\$ 3,868
Income From Discontinued Operations	–	–	70
Total Income	\$ 4,270	\$ 4,168	\$ 3,938

U.S. upstream income of \$4.3 billion in 2006 increased approximately \$100 million from 2005. Earnings in 2006 benefited about \$850 million from higher average prices on oil-equivalent production and the effect of seven additional months of production from the Unocal properties that were acquired in August 2005. Substantially offsetting these

benefits were increases in operating expense and expenses for depreciation and exploration. Included in the operating expense increases were costs associated with the carryover effects of hurricanes in the Gulf of Mexico in 2005.

Income of \$4.2 billion in 2005 was \$230 million higher than 2004. The 2004 amount included gains of approximately \$400 million from asset sales. Higher prices for crude oil and natural gas in 2005 and five months of earnings from the former Unocal operations contributed approximately \$2 billion to the increase between periods. Approximately 90 percent of this amount related to the effects of higher prices on heritage-Chevron production. These benefits were substantially offset by the adverse effects of lower production, higher operating expenses and higher depreciation expense associated with the heritage-Chevron properties.

The company's average realization for crude oil and natural gas liquids in 2006 was \$56.66 per barrel, compared with \$46.97 in 2005 and \$34.12 in 2004. The average



natural gas realization was \$6.29 per thousand cubic feet in 2006, compared with \$7.43 and \$5.51 in 2005 and 2004, respectively.

Net oil-equivalent production in 2006 averaged 763,000 barrels per day, up 5 percent from 2005 and down 7 percent from 2004. The increase between 2005 and 2006 was due to the full-year benefit of production from the former Unocal properties. The decrease from 2004 was associated mainly with the effects of hurricanes, property sales and normal field declines, partially offset by additional volumes from the former Unocal properties.

The net liquids component of oil-equivalent production for 2006 averaged 462,000 barrels per day, an increase of approximately 2 percent from 2005 and a decrease of 9 percent from 2004. Net natural gas production averaged 1.8 billion cubic feet per day in 2006, up 11 percent from 2005 and down 3 percent from 2004.

Refer to the "Selected Operating Data" table, on page 35, for the three-year comparative production volumes in the United States.

International Upstream – Exploration and Production

Millions of dollars	2006	2005	2004
Income From Continuing Operations*	\$ 8,872	\$ 7,556	\$ 5,622
Income From Discontinued Operations	–	–	224
Total Income*	\$ 8,872	\$ 7,556	\$ 5,846

*Includes Foreign Currency Effects: \$ (371) 2006, \$ 14 2005, \$ (129) 2004

International upstream income of approximately \$8.9 billion in 2006 increased \$1.3 billion from 2005. Earnings in 2006 benefited approximately \$3.0 billion from higher prices for crude oil and natural gas and an additional seven months of production from the former Unocal properties. About 70 percent of this benefit was associated with the impact of higher prices. Substantially offsetting these benefits were increases in depreciation expense, operating expense and exploration expense. Also adversely affecting 2006 income were higher taxes related to an increase in tax rates in the U.K. and Venezuela and settlement of tax claims and other tax items in Venezuela, Angola and Chad. Foreign currency effects reduced earnings by \$371 million in 2006, but increased income \$14 million in 2005.

Income in 2005 was approximately \$7.5 billion, compared with \$5.8 billion in 2004, which included gains of approximately \$850 million from property sales. Higher prices for crude oil and natural gas in 2005 and five months of earnings from the former Unocal operations increased income approximately \$2.9 billion between periods. About 80 percent of this benefit arose from the effects of higher prices on heritage-Chevron production. Partially offsetting these benefits were higher expenses between periods for certain income tax items, including the absence of a \$200 million benefit in 2004 relating to changes in income tax laws. Foreign currency effects increased income \$14 million in 2005 but reduced income \$129 million in 2004.

The company's average realization for crude oil and natural gas liquids in 2006 was \$57.65 per barrel, compared with \$47.59 in 2005 and \$34.17 in 2004. The average natural gas realization was \$3.73 per thousand cubic feet in 2006, compared with \$3.19 and \$2.68 in 2005 and 2004, respectively.

Net oil-equivalent production of 1.9 million barrels per day in 2006, including about 100,000 net barrels per day from oil sands in Canada and production under an operating service agreement in Venezuela prior to its conversion to a joint stock company, increased about 6 percent from 2005 and 13 percent from 2004. This trend was largely the result of the effects of the Unocal acquisition in August 2005, partially offset by the effect of normal field declines and property sales in 2004.

The net liquids component of oil-equivalent production was 1.4 million barrels per day in 2006, an increase of approximately 2 percent from 2005 and 2004. Net natural gas production of 3.1 billion cubic feet per day in 2006 was up 21 percent and 51 percent from 2005 and 2004, respectively.

Refer to the "Selected Operating Data" table, on page 35, for the three-year comparative of international production volumes.

U.S. Downstream – Refining, Marketing and Transportation

Millions of dollars	2006	2005	2004
Income	\$ 1,938	\$ 980	\$ 1,261

U.S. downstream earnings of \$1.9 billion in 2006 increased about \$1 billion from 2005 and approximately \$700 million from 2004. Average refined-product margins in 2006 were higher than in 2005, which in turn were also

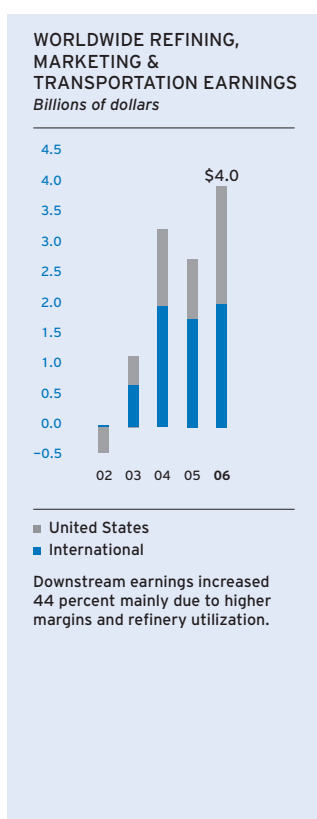
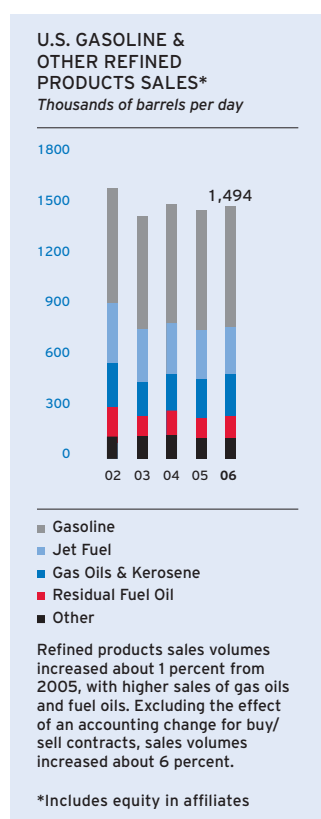
reported sales volume for 2006 was on a different basis than in 2005 and 2004 due to a change in accounting rules that became effective April 1, 2006, for certain purchase and sale (buy/sell) contracts with the same counterparty. Excluding the impact of the accounting change, refined product sales in 2006 increased by approximately 6 percent and 3 percent from 2005 and 2004, respectively. Branded gasoline sales volumes of approximately 614,000 barrels per day in 2006 increased about 4 percent from 2005, largely due to the growth of the Texaco brand. In 2005, refined-product sales volumes decreased about 2 percent from 2004, primarily due to disruption related to the hurricanes.

Refer to the "Selected Operating Data" table, on page 35, for the three-year comparative refined-product sales volumes in the United States. Refer also to Note 14, "Accounting for Buy/Sell Contracts," on page 67 for a discussion of the accounting for purchase and sale contracts with the same counterparty.

International Downstream – Refining, Marketing and Transportation

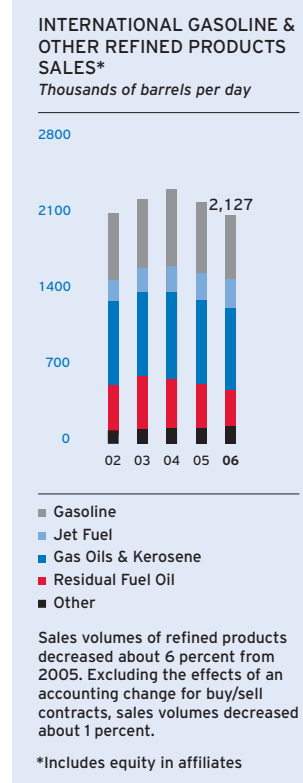
Millions of dollars	2006	2005	2004
Income*	\$ 2,035	\$ 1,786	\$ 1,989
*Includes Foreign Currency Effects:	\$ 98	\$ (24)	\$ 7

International downstream income of \$2 billion in 2006 increased about \$250 million from 2005 and about \$50 million from 2004. The increase in 2006 from 2005 was associated mainly with the benefit of higher-refined product margins in Asia-Pacific and Canada and improved results from crude-oil and refined-product trading activities. The decrease in earnings in 2005 from 2004 was due mainly to lower sales volumes; higher costs for fuel and transportation; expenses associated with a fire at a 40 percent-owned, nonoperated terminal in the United Kingdom; and tax adjustments in various countries. These items more than offset an improvement in average refined-product margins between periods. Foreign currency effects improved income by \$98 million and \$7 million in 2006



higher than in 2004. Refinery crude inputs were higher in 2006 than in the other comparative periods and also benefited earnings. However, earnings declined in 2005 from a year earlier due mainly to increased downtime at the company's refineries, including the shutdown of operations at Pascagoula, Mississippi, for more than a month due to hurricanes in the Gulf of Mexico. The company's marketing and pipeline operations along the Gulf Coast were also disrupted for an extended period due to the hurricanes. Fuel costs were also higher in 2005 than in 2004.

Sales volumes of refined products in 2006 were approximately 1.5 million barrels per day, an increase of 1 percent from 2005 and relatively unchanged from 2004. The

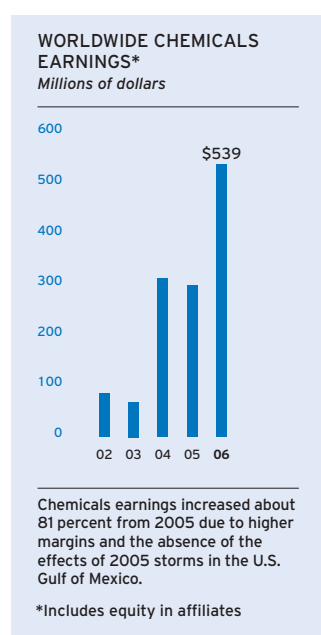


and 2004, respectively, but reduced income by \$24 million in 2005.

Refined-product sales volumes were 2.1 million barrels per day in 2006, about 6 percent lower than 2005. Excluding the accounting change for buy/sell contracts, sales were down 1 percent between 2005 and 2006. Refined-product sales volume of 2.3 million barrels per day in 2005 were about 4 percent lower than in 2004, primarily the result of lower gasoline trading activity and lower fuel oil sales. Refer to the "Selected Operating Data" table, on page 35, for the three-year comparative refined-product sales volumes in the international areas.

Chemicals

Millions of dollars	2006	2005	2004
Income*	\$ 539	\$ 298	\$ 314
*Includes Foreign Currency Effects:	\$ (8)	\$ -	\$ (3)



The chemicals segment includes the company's Oronite subsidiary and the 50 percent-owned Chevron Phillips Chemical Company LLC (CPCChem). In 2006, earnings of \$539 million increased about \$200 million from both 2005 and 2004. Margins in 2006 for commodity chemicals at CPCChem and for fuel and lubricant additives at Oronite were higher than in 2005 and 2004. The earnings decline from 2004 to 2005 was mainly attributable to plant outages and expenses in the Gulf of Mexico region due to hurricanes, which affected both Oronite and CPCChem.

All Other

Millions of dollars	2006	2005	2004
Net Charges*	\$ (516)	\$ (689)	\$ (20)
*Includes Foreign Currency Effects:	\$ 62	\$ (51)	\$ 44

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

Net charges of \$516 million in 2006 decreased \$173 million from \$689 million in 2005. Excluding the effects of foreign currency, net charges declined \$60 million between periods. Interest income was higher in 2006, and interest expense was lower.

Between 2004 and 2005, net charges increased \$669 million. Excluding the effects of foreign exchange, net

charges increased \$574 million. Approximately \$400 million of the increase was related to larger benefits in 2004 from corporate-level tax adjustments. Higher charges in 2005 also were associated with environmental remediation of properties that had been sold or idled and Unocal corporate-level activities. Interest expense was higher in 2005 due to an increase in interest rates and the debt assumed with the Unocal acquisition.

CONSOLIDATED STATEMENT OF INCOME

Comparative amounts for certain income statement categories are shown below:

Millions of dollars	2006	2005	2004
Sales and other operating revenues	\$ 204,892	\$ 193,641	\$ 150,865

Sales and other operating revenues in 2006 increased over 2005 due primarily to higher prices for refined products. The increase in 2005 from 2004 was a result of the same factor plus the effect of higher average prices for crude oil and natural gas. The higher revenues in 2006 were net of an impact from the change in the accounting for buy/sell contracts, as described in Note 14 on page 67.

Millions of dollars	2006	2005	2004
Income from equity affiliates	\$ 4,255	\$ 3,731	\$ 2,582

Increased income from equity affiliates in 2006 was mainly due to improved results for Tengizchevroil (TCO) and CPCChem. The improvement in 2005 from 2004 was primarily due to improved results for TCO and Hamaca (Venezuela). Refer to Note 12, beginning on page 65, for a discussion of Chevron's investment in affiliated companies.

Millions of dollars	2006	2005	2004
Other income	\$ 971	\$ 828	\$ 1,853

Other income of nearly \$1.9 billion in 2004 included approximately \$1.3 billion of gains from upstream property sales. Interest income contributed \$600 million, \$400 million and \$200 million in 2006, 2005 and 2004, respectively. Average interest rates and balances of cash and marketable securities increased each year. Foreign currency losses were \$260 million in 2006 and \$60 million in both 2005 and 2004.

Millions of dollars	2006	2005	2004
Purchased crude oil and products	\$ 128,151	\$ 127,968	\$ 94,419

Crude oil and product purchases in 2006 increased from 2005 on higher prices for crude oil and refined products and the inclusion of Unocal-related amounts for a full year in 2006. The increase was mitigated by the effect of the accounting change in April 2006 for buy/sell contracts. Purchase costs increased 35 percent in 2005 from the prior year as a result of higher prices for crude oil, natural gas and refined products, as well as to the inclusion of Unocal-related amounts for five months.

<i>Millions of dollars</i>	2006	2005	2004
Operating, selling, general and administrative expenses	\$ 19,717	\$ 17,019	\$ 14,389

Operating, selling, general and administrative expenses in 2006 increased 16 percent from a year earlier. Expenses associated with the former Unocal operations are included for the full year in 2006, vs. five months in 2005. Besides this effect, expenses were higher in 2006 for labor, transportation, uninsured costs associated with the hurricanes in 2005 and a number of corporate items that individually were not significant. Total expenses increased in 2005 from 2004 due mainly to the inclusion of former-Unocal expenses for five months, higher costs for labor and transportation, uninsured costs associated with storms in the Gulf of Mexico, and asset write-offs.

<i>Millions of dollars</i>	2006	2005	2004
Exploration expense	\$ 1,364	\$ 743	\$ 697

Exploration expenses in 2006 increased from 2005 mainly due to higher amounts for well write-offs and geological and geophysical costs for operations outside the United States, as well as the inclusion of expenses for the former Unocal operations for a full year in 2006. Expenses increased in 2005 from 2004 due mainly to the inclusion of Unocal-related amounts for five months.

<i>Millions of dollars</i>	2006	2005	2004
Depreciation, depletion and amortization	\$ 7,506	\$ 5,913	\$ 4,935

Depreciation, depletion and amortization expenses increased from 2004 through 2006 mainly as a result of depreciation and depletion expense for the former Unocal assets and higher depreciation rates for certain heritage-Chevron crude oil and natural gas producing fields worldwide.

<i>Millions of dollars</i>	2006	2005	2004
Interest and debt expense	\$ 451	\$ 482	\$ 406

Interest and debt expense in 2006 decreased from 2005 primarily due to lower average debt balances and an increase in the amount of interest capitalized, partially offset by higher average interest rates on commercial paper and other variable-rate debt. The increase in 2005 over 2004 was mainly due to the inclusion of debt assumed with the Unocal acquisition and higher average interest rates for commercial paper borrowings.

<i>Millions of dollars</i>	2006	2005	2004
Taxes other than on income	\$ 20,883	\$ 20,782	\$ 19,818

Taxes other than on income were essentially unchanged in 2006 from 2005, with the effect of higher U.S. refined product sales being offset by lower sales volumes subject to duties in the company's European downstream operations. The increase in 2005 from 2004 was the result of higher international taxes assessed on product values, higher duty rates in the areas of the company's European downstream operations and higher U.S. federal excise taxes on jet fuel resulting from a change in tax law that became effective in 2005.

<i>Millions of dollars</i>	2006	2005	2004
Income tax expense	\$ 14,838	\$ 11,098	\$ 7,517

Effective income tax rates were 46 percent in 2006, 44 percent in 2005 and 37 percent in 2004. The higher tax rate in 2006 included the effect of one-time charges totaling \$400 million, including an increase in tax rates on upstream operations in the U.K. North Sea and settlement of a tax claim in Venezuela. Rates were higher in 2005 compared with the prior year due to an increase in earnings in countries with higher tax rates and the absence of benefits in 2004 from changes in the income tax laws for certain international operations. Refer also to the discussion of income taxes in Note 16 beginning on page 68.

SELECTED OPERATING DATA^{1,2}

	2006	2005	2004
U.S. Upstream³			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)	462	455	505
Net Natural Gas Production (MMCFPD) ⁴	1,810	1,634	1,873
Net Oil-Equivalent Production (MBOEPD)	763	727	817
Sales of Natural Gas (MMCFPD)	7,051	5,449	4,518
Sales of Natural Gas Liquids (MBPD)	124	151	177
Revenues From Net Production			
Liquids (\$/Bbl)	\$56.66	\$ 46.97	\$ 34.12
Natural Gas (\$/MCF)	\$ 6.29	\$ 7.43	\$ 5.51
International Upstream³			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)	1,270	1,214	1,205
Net Natural Gas Production (MMCFPD) ⁴	3,146	2,599	2,085
Net Oil-Equivalent			
Production (MBOEPD) ⁵	1,904	1,790	1,692
Sales Natural Gas (MMCFPD)	3,478	2,450	2,039
Sales Natural Gas Liquids (MBPD)	102	120	118
Revenues From Liftings			
Liquids (\$/Bbl)	\$57.65	\$ 47.59	\$ 34.17
Natural Gas (\$/MCF)	\$ 3.73	\$ 3.19	\$ 2.68
U.S. and International Upstream³			
Net Oil-Equivalent Production Including			
Other Produced Volumes (MBOEPD) ^{4,5}			
United States	763	727	817
International	1,904	1,790	1,692
Total	2,667	2,517	2,509
U.S. Downstream			
Gasoline Sales (MBPD) ⁶	712	709	701
Other Refined Products Sales (MBPD)	782	764	805
Total (MBPD) ⁷	1,494	1,473	1,506
Refinery Input (MBPD)	939	845	914
International Downstream			
Gasoline Sales (MBPD) ⁶	595	662	715
Other Refined Products Sales (MBPD)	1,532	1,590	1,653
Total (MBPD) ^{7,8}	2,127	2,252	2,368
Refinery Input (MBPD)	1,050	1,038	1,044

¹ Includes equity in affiliates.

² 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.

³ Includes net production beginning August 2005, for properties associated with acquisition of Unocal.

⁴ Includes natural gas consumed in operations (MMCFPD):

United States	56	48	50
International	419	356	293

⁵ Includes other produced volumes (MBPD):

Athabasca Oil Sands – Net	27	32	27
Boscan Operating Service Agreement	82	111	113
Total	109	143	140

⁶ Includes branded and unbranded gasoline.

⁷ Includes volumes for buy/sell contracts (MBPD):

United States	26	88	84
International	24	129	96

⁸ Includes sales of affiliates (MBPD):

Total	492	498	502
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INFORMATION RELATED TO INVESTMENT IN DYNEGY INC.

At year-end 2006, Chevron owned a 19 percent equity interest in the common stock of Dynegy Inc., a provider of electricity to markets and customers throughout the United States.

Investment in Dynegy Common Stock At December 31, 2006, the carrying value of the company's investment in Dynegy common stock was approximately \$250 million. This amount was about \$180 million below the company's proportionate interest in Dynegy's underlying net assets. This difference is primarily the result of 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 difference had been assigned to the extent practicable to specific Dynegy assets and liabilities, based upon the company's analysis of the various factors associated with the decline in value of the Dynegy shares. The company's equity share of Dynegy's reported earnings is adjusted quarterly when appropriate to recognize a portion of 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, 2006, was approximately \$700 million.

Investments in Dynegy Preferred Stock In May 2006, the company's investment in Dynegy Series C preferred stock was redeemed at its face value of \$400 million. Upon redemption of the preferred stock, the company recorded a before-tax gain of \$130 million (\$87 million after tax).

Dynegy Proposed Business Combination with LS Power Group Dynegy and LS Power Group, a privately held power plant investor, developer and manager, announced in September 2006 that the companies had executed a definitive agreement to combine Dynegy's assets and operations with LS Power Group's power-generation portfolio and for Dynegy to acquire a 50 percent ownership interest in a development joint venture with LS Power. Upon close of the transaction, Chevron will receive the same number of shares of the new company's Class A common stock that it currently holds in Dynegy. Chevron's ownership interest in the combined company will be approximately 11 percent. The transaction is subject to specified conditions, including the affirmative vote of two-thirds of Dynegy's common shareholders and the receipt of regulatory approvals.

LIQUIDITY AND CAPITAL RESOURCES

Cash, cash equivalents and marketable securities Total balances were \$11.4 billion and \$11.1 billion at December 31, 2006 and 2005, respectively. Cash provided by operating activities in 2006 was \$24.3 billion, compared with \$20.1 billion in 2005 and \$14.7 billion in 2004.

The 2006 increase in cash provided by operating activities mainly reflected higher earnings in the upstream and downstream segments, including a full year of earnings from the former Unocal operations that were acquired in August 2005. Cash provided by operating activities was net of contributions to employee pension plans of \$0.4 billion, \$1.0 billion and \$1.6 billion in 2006, 2005 and 2004, respectively. Cash provided by investing activities included proceeds from asset sales of \$1.0 billion in 2006, \$2.7 billion in 2005 and \$3.7 billion in 2004.

Cash provided by operating activities and asset sales during 2006 was sufficient to fund the company's \$13.8 billion capital and exploratory program, pay \$4.4 billion of dividends to stockholders, repay approximately \$2.9 billion in debt and repurchase \$5 billion of common stock.

Dividends The company paid dividends of approximately \$4.4 billion in 2006, \$3.8 billion in 2005 and \$3.2 billion in 2004. In April 2006, the company increased its quarterly common stock dividend by 15.5 percent to 52 cents per share.

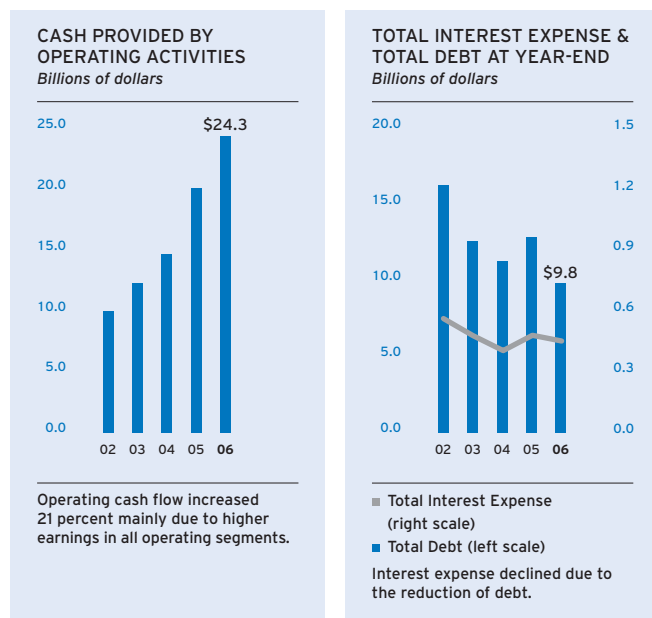
Debt, capital lease and minority interest obligations Total debt and capital lease balances were \$9.8 billion at

The \$3.1 billion reduction in total debt and capital lease obligations during 2006 included the early redemption and maturity of several individual debt issues. In the first quarter, \$185 million of Union Oil Company bonds matured. In the second quarter, the company redeemed approximately \$1.7 billion of Unocal debt prior to maturity. In the fourth quarter, a \$129 million Texaco Capital Inc. bond matured, and Union Oil Company bonds of \$196 million were redeemed prior to maturity. Commercial paper balances at the end of 2006 were reduced \$626 million from year-end 2005. In February 2007, a \$144 million Texaco Capital Inc. bond matured.

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 \$6.6 billion at December 31, 2006, up from \$5.6 billion at year-end 2005. Of these amounts, \$4.5 billion and \$4.9 billion were reclassified to long-term at the end of each period, respectively. At year-end 2006, settlement of the reclassified amount was not expected to require the use of working capital in 2007, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance the amounts on a long-term basis. The company's practice has been to maintain commercial paper levels it believes appropriate and economic.

At year-end 2006, the company had \$5 billion in committed credit facilities with various major banks, which permitted the refinancing of short-term obligations on a long-term basis. These facilities support commercial paper borrowings and can be used for general corporate purposes. The company's practice has been to continually replace expiring commitments with new commitments on substantially the same terms, maintaining levels management believes appropriate. Any borrowings under the facilities would be unsecured indebtedness at interest rates based on the London Interbank Offered Rate or an average of base lending rates published by specified banks and on terms reflecting the company's strong credit rating. No borrowings were outstanding under these facilities at December 31, 2006. In addition, the company has three existing effective "shelf" registration statements on file with the Securities and Exchange Commission that together would permit additional registered debt offerings up to an aggregate \$3.8 billion of debt securities.

In 2004, Chevron entered into \$1 billion of interest rate swap transactions, in which the company receives a fixed interest rate and pays a floating rate, based on the notional principal amounts. Under the terms of the swap agreements, of which \$250 million and \$750 million will terminate in September 2007 and February 2008, respectively, the net cash settlement will be based on the difference between fixed interest rates and floating interest rates.



December 31, 2006, down from \$12.9 billion at year-end 2005. The company also had minority interest obligations of \$209 million, up from \$200 million at December 31, 2005.

The company has outstanding public bonds issued by Chevron Corporation Profit Sharing/Savings Plan Trust Fund, Chevron Canada Funding Company (formerly Chevron Texaco Capital Company), Texaco Capital Inc. and Union Oil Company of California. All of these securities are guaranteed by Chevron Corporation and are rated AA by Standard and Poor's Corporation and Aa2 by Moody's Investors Service. The company's U.S. commercial paper is rated A-1+ by Standard and Poor's and P-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 that it has substantial borrowing capacity to meet unanticipated cash requirements and that during periods of low prices for crude oil and natural gas and narrow margins for refined products and commodity chemicals, 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.

Common stock repurchase program A \$5 billion stock repurchase program initiated in December 2005 was completed in November 2006. During 2006, about 78.5 million common shares were repurchased under this program at a total cost of \$4.9 billion.

In December 2006, the company authorized the acquisition of up to an additional \$5 billion of its common shares from time to time at prevailing prices, as permitted by securities laws and other legal requirements and subject to market conditions and other factors. The program is for a period of up to three years and may be discontinued at any time. Under this program, the company acquired approximately 1.3 million shares in the open market for \$100 million during December 2006 and through mid-February 2007 increased the total shares acquired to 8.2 million at a cost of \$592 million.

Capital and exploratory expenditures Total reported expenditures for 2006 were \$16.6 billion, including \$1.9 billion for the company's share of affiliates' expenditures, which did not require cash outlays by the company. In 2005 and 2004, expenditures were \$11.1 billion and \$8.3 billion, respectively, including the company's share of affiliates' expenditures of \$1.7 billion and \$1.6 billion in the cor-

responding periods. The 2005 amount excludes the \$17.3 billion acquisition of Unocal Corporation.

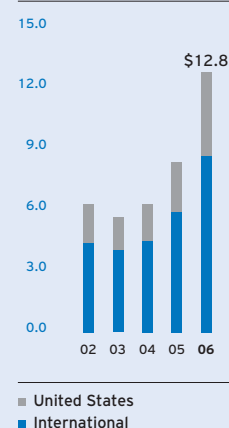
Of the \$16.6 billion in expenditures for 2006, about three-fourths, or \$12.8 billion, related to upstream activities. Approximately the same percentage was also expended for upstream operations in 2005 and 2004. International upstream accounted for about 70 percent of the worldwide upstream investment in each of the three years, reflecting the company's continuing focus on opportunities that are available outside the United States.

In 2007, the company estimates capital and exploratory expenditures will be 18 percent higher at \$19.6 billion, including \$2.4 billion of spending by affiliates. About three-fourths of the total, or \$14.6 billion, is budgeted for exploration and production activities, with \$10.6 billion of this amount outside the United States. Spending in 2007 is primarily targeted for exploratory prospects in the deepwater Gulf of Mexico and western Africa and major development projects in Angola, Australia, Brazil, Kazakhstan, Nigeria, the deepwater Gulf of Mexico and an oil sands project in Canada.

Worldwide downstream spending in 2007 is estimated at \$3.8 billion, with about \$1.6 billion for projects in the United States. Capital projects include upgrades to refineries in the United States and South Korea and construction of liquefied natural gas tankers and gas-to-liquids facilities in support of associated upstream projects.

Investments in chemicals, technology and other corporate businesses in 2007 are budgeted at \$1.2 billion. Technology investments include projects related to molecular transformation, unconventional hydrocarbons, oil and gas reservoir management and development of second-generation biofuel production.

EXPLORATION & PRODUCTION – CAPITAL & EXPLORATORY EXPENDITURES*
Billions of dollars



Exploration and production expenditures increased more than \$4 billion in 2006. Many significant projects were in their capital-intensive phase; outlays also included the full-year effect of spending on former Unocal properties.

*Includes equity in affiliates

Capital and Exploratory Expenditures

Millions of dollars	2006			2005			2004		
	U.S.	Int'l.	Total	U.S.	Int'l.	Total	U.S.	Int'l.	Total
Upstream – Exploration and Production	\$ 4,123	\$ 8,696	\$ 12,819	\$ 2,450	\$ 5,939	\$ 8,389	\$ 1,820	\$ 4,501	\$ 6,321
Downstream – Refining, Marketing and Transportation	1,176	1,999	3,175	818	1,332	2,150	497	832	1,329
Chemicals	146	54	200	108	43	151	123	27	150
All Other	403	14	417	329	44	373	512	3	515
Total	\$ 5,848	\$ 10,763	\$ 16,611	\$ 3,705	\$ 7,358	\$ 11,063	\$ 2,952	\$ 5,363	\$ 8,315
Total, Excluding Equity in Affiliates	\$ 5,642	\$ 9,050	\$ 14,692	\$ 3,522	\$ 5,860	\$ 9,382	\$ 2,729	\$ 4,024	\$ 6,753

Pension Obligations In 2006, the company's pension plan contributions totaled approximately \$450 million. Approximately \$225 million of the total was contributed to U.S. plans. In 2007, the company estimates total contributions will be \$500 million. Actual amounts are dependent upon plan-investment results, changes in pension obligations, regulatory requirements and other economic factors. Additional funding may 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 44.

FINANCIAL RATIOS

Financial Ratios

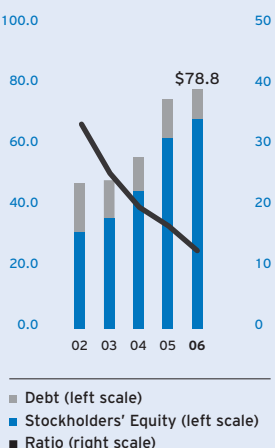
	At December 31		
	2006	2005	2004
Current Ratio	1.3	1.4	1.5
Interest Coverage Ratio	53.5	47.5	47.6
Total Debt/Total Debt-Plus-Equity	12.5%	17.0%	19.9%

Current Ratio – current assets divided by current liabilities. The current ratio in all periods was adversely affected by the fact that Chevron's inventories are valued on a Last-In-First-Out basis. At year-end 2006, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately \$6 billion.

Interest Coverage Ratio – income before income tax expense, plus interest and debt expense and amortization of capitalized interest, divided by before-tax interest costs. The interest coverage ratio was higher in 2006 compared with 2005, primarily due to higher before-tax income and lower average debt balances. The company's interest coverage ratio was essentially unchanged between 2005 and 2004.

Debt Ratio – total debt as a percentage of total debt plus equity. The decrease between 2005 and 2006 was due to lower average debt levels and an increase in stockholders' equity. Although total debt was slightly higher at the end of 2005 than a year earlier due to the assumption of debt associated with the Unocal acquisition, the debt ratio declined as a result of higher stockholders' equity balances for retained earnings

TOTAL DEBT TO TOTAL DEBT-PLUS-EQUITY RATIO
Billions of dollars/Percent



Chevron's ratio of total debt to total debt-plus-equity fell to 12.5 percent at year-end due to lower debt and higher stockholders' equity.

and the capital stock that was issued in connection with the Unocal acquisition.

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

Direct or Indirect Guarantees*

Millions of dollars	Commitment Expiration by Period				
	Total	2007	2008–2010	2011	After 2011
Guarantees of non-consolidated affiliates or joint-venture obligations	\$ 296	\$ 21	\$ 253	\$ 9	\$ 13
Guarantees of obligations of third parties	131	4	113	3	11
Guarantees of Equilon debt and leases	119	14	38	11	56

*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 39.

At December 31, 2006, the company and its subsidiaries provided guarantees, either directly or indirectly, of \$296 million for notes and other contractual obligations of affiliated companies and \$131 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.

The \$296 million in guarantees provided to affiliates related to borrowings for capital projects. These guarantees were undertaken to achieve lower interest rates and generally cover the construction periods of the capital projects. Included in these amounts are the company's guarantees of \$214 million associated with a construction completion guarantee for the debt financing of the company's equity interest in the BTC crude oil pipeline project. Substantially all of the \$296 million guaranteed will expire between 2007 and 2011, with the remaining 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.

The \$131 million in guarantees provided on behalf of third parties relate to construction loans to governments of certain of the company's international upstream operations. Substantially all of the \$131 million in guarantees expire by 2011, with the remainder expiring by 2015. 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.

At December 31, 2006, Chevron also had outstanding guarantees for about \$120 million of Equilon debt and leases. Following the February 2002 disposition of its interest in Equilon, the company received an indemnification from Shell 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 2007 through 2011 period, with the guarantees of the remaining amounts expiring by 2019.

Indemnifications The company 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 company would be required to perform if the indemnified liabilities become actual losses. Were that to occur, the company could be required to make future payments up to \$300 million. Through the end of 2006, the company paid approximately \$48 million under these indemnities and continues to be obligated for possible additional indemnification payments in the future.

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 period of Texaco's ownership interest 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 indemnities must be asserted either as early as February 2007 or no later than February 2009, and claims relating to Motiva indemnities must be asserted either as early as February 2007 or no later than February 2012. Under the terms of these 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 posts 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 applicable incident.

In the acquisition of Unocal, the company assumed certain indemnities relating to contingent environmental liabilities associated with assets that were sold in 1997. Under the indemnification agreement, the company's liability is unlimited until April 2022, when the liability expires. The acquirer shares in certain environmental remediation costs up to a maximum obligation of \$200 million, which had not been reached as of December 31, 2006.

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, 2006, approximately \$1.2 billion, representing about 7 percent of Chevron's total current accounts and notes receivable balance, were securitized. Chevron's total estimated financial exposure under these securitizations at December 31, 2006, was approximately \$80 million. These arrangements have the effect of accelerating Chevron's collection of the securitized amounts. In the event that the SPEs experience major defaults in the collection of receivables, Chevron believes that it would have no loss exposure connected with third-party investments in these securitizations.

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements

The company and its subsidiaries have certain other contingent liabilities relating to long-term unconditional purchase obligations and commitments, including throughput 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, drilling rigs, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate approximate amounts of required payments under these various commitments are: 2007 – \$3.2 billion; 2008 – \$1.7 billion; 2009 – \$2.1 billion; 2010 – \$1.9 billion; 2011 – \$0.9 billion; 2012 and after – \$4.1 billion. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately \$3.0 billion in 2006, \$2.1 billion in 2005 and \$1.6 billion in 2004.

Minority Interests The company has commitments of \$209 million related to minority interests in subsidiary companies.

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

Contractual Obligations

Millions of dollars	Payments Due by Period				
	Total	2007	2008–2010	2011	After 2011
On Balance Sheet:					
Short-Term Debt ¹	\$ 2,159	\$ 2,159	\$ –	\$ –	\$ –
Long-Term Debt ^{1,2}	7,405	–	5,868	50	1,487
Noncancelable Capital Lease Obligations	274	–	138	40	96
Interest	5,269	491	1,173	366	3,239
Off-Balance-Sheet:					
Noncancelable Operating Lease Obligations	3,058	509	1,374	311	864
Throughput and Take-or-Pay Agreements	9,796	2,765	3,027	475	3,529
Other Unconditional Purchase Obligations	4,072	383	2,696	427	566

¹ \$4.5 billion of short-term debt that the company expects to refinance is included in long-term debt. The repayment schedule above reflects the projected repayment of the entire amounts in the 2008–2010 period.

² Includes guarantees of \$213 of ESOP (employee stock ownership plan) debt due after 2007. The 2007 amount of \$20, which was scheduled for payment on the first business day of January 2007, was paid in late December 2006.

FINANCIAL AND DERIVATIVE INSTRUMENTS

Commodity Derivative Instruments Chevron is exposed to market risks related to the price volatility of crude oil, refined products, natural gas, natural gas liquids, liquefied natural gas and refinery feedstocks.

The company uses derivative commodity instruments to manage these exposures on a portion of its activity, including: firm commitments and anticipated transactions for the purchase, sale and storage of crude oil, refined products, natural gas, natural gas liquids and feedstock for company refineries. The company also uses derivative commodity instruments for limited trading purposes. The results of this activity were not material to the company's financial position, net income or cash flows in 2006.

The company's market exposure positions are monitored and managed on a daily basis by an internal Risk

Control group to ensure compliance with the company's risk management policies that have 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, options, and swap contracts traded on the NYMEX (New York Mercantile Exchange) and on electronic platforms of ICE (Inter-Continental Exchange) and GLOBEX (Chicago Mercantile Exchange). In addition, crude oil, natural gas and refined product swap contracts and option contracts are entered into principally with major financial institutions and other oil and gas companies in the "over-the-counter" markets.

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 published market quotes and other independent third-party quotes.

Each hypothetical 10 percent increase in the price of natural gas, crude oil and refined products would increase the fair value of the natural gas purchase derivative contracts by approximately \$10 million, increase the fair value of the crude oil purchase derivative contracts by about \$4 million and reduce the fair value of the refined product sale derivative contracts by about \$30 million, respectively. The same hypothetical decrease in the prices of these commodities would result in approximately the same opposite effects on the fair values of the contracts.

The hypothetical effect on these contracts was estimated by calculating the fair value of the contracts as the difference between the hypothetical and current market 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 of a hypothetical 10 percent increase in the value of the U.S. dollar at year-end 2006 would be a reduction in the fair value of the foreign exchange contracts of approximately \$40 million. The effect would be the opposite for a hypothetical 10 percent decrease in the year-end value of the U.S. dollar.

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.

At year-end 2006, the weighted average maturity of "receive fixed" interest rate swaps was approximately one year. There were no "receive floating" swaps outstanding at year end. A hypothetical increase of 10 basis points in fixed interest rates would reduce the fair value of the "receive fixed" swaps by approximately \$2 million.

For the financial and derivative instruments discussed above, there was not a material change in market risk between 2006 and 2005.

The hypothetical variances used in this section were selected for illustrative purposes only and do not represent the company's estimation of market changes. The actual impact of future market changes could differ materially due to factors discussed elsewhere in this report, including those set forth under the heading "Risk Factors" in Part I, Item 1A, of the company's 2006 Annual Report on Form 10-K.

TRANSACTIONS WITH RELATED PARTIES

Chevron enters into a number of business arrangements with related parties, principally its equity affiliates. These arrangements include long-term supply or offtake agreements. Long-term purchase agreements are in place with the company's refining affiliate in Thailand. Refer to page 39 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

MTBE Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. Chevron is a party to approximately 75 lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners, related to the use of MTBE in certain oxygenated gasolines and the alleged seepage of MTBE into groundwater. Resolution of these actions may ultimately 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. The company currently does not use MTBE in the manufacture of gasoline in the United States.

RFG Patent Fourteen purported class actions were brought by consumers of reformulated gasoline (RFG)

alleging that Unocal misled the California Air Resources Board into adopting standards for composition of RFG that overlapped with Unocal's undisclosed and pending patents. Eleven lawsuits are now consolidated in U.S. District Court for the Central District of California and three are consolidated in California State Court. Unocal is alleged to have monopolized, conspired and engaged in unfair methods of competition, resulting in injury to consumers of RFG. Plaintiffs in both consolidated actions seek unspecified actual and punitive damages, attorneys' fees, and interest on behalf of an alleged class of consumers who purchased "summertime" RFG in California from January 1995 through August 2005. Unocal believes it has valid defenses and intends to vigorously defend against these lawsuits. The company's potential exposure related to these lawsuits cannot currently be estimated.

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, federal Superfund sites and analogous sites under state laws, refineries, crude

oil fields, service stations, terminals, land development areas, and mining operations, whether operating, closed or divested. These future costs are not fully determinable 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 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 chemical companies.

The following table displays the annual changes to the company's before-tax environmental remediation reserves, including those for federal Superfund sites and analogous sites under state laws.

Millions of dollars	2006	2005	2004
Balance at January 1	\$ 1,469	\$ 1,047	\$ 1,149
Net Additions	366	731	155
Expenditures	(394)	(309)	(257)
Balance at December 31	\$ 1,441	\$ 1,469	\$ 1,047

Chevron's environmental reserve as of December 31, 2006, was \$1,441 million. Included in this balance were remediation activities of 242 sites for which the company had been identified as a potentially responsible party or otherwise involved in the remediation by the U.S. Environmental Protection Agency (EPA) or other regulatory agencies under the provisions of the federal Superfund law or analogous state laws. The company's remediation reserve for these sites at year-end 2006 was \$122 million. The federal Superfund law and analogous state laws provide for joint and several liability for all responsible parties. Any future actions by the EPA or other regulatory agencies to require Chevron 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.

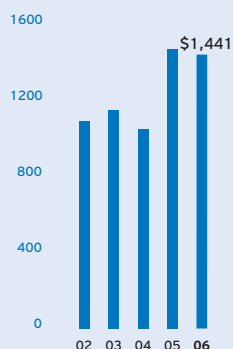
Of the remaining year-end 2006 environmental reserves balance of \$1,319 million, \$834 million related to approximately 2,250 sites for the company's U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals), and pipelines. The remaining \$485 million was associated with various sites in the international downstream (\$117 million), upstream (\$252 million), chemicals (\$61 million) and other (\$55 million). Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company's plans and activities to remediate soil or groundwater contamination or both. These and other activities include one or more of the following: site assessment; soil excavation; offsite disposal of contaminants; onsite containment, remediation and/or extraction of petroleum hydrocarbon liquid and vapor from soil; groundwater extraction and treatment; and monitoring of the natural attenuation of the contaminants.

The company manages environmental liabilities under specific sets of regulatory requirements, which in the United States include the Resource Conservation and Recovery Act and various state or local regulations. No single remediation site at year-end 2006 had a recorded liability that was material to the company's financial position, results of operations 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 not fully determinable 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.

Effective January 1, 2003, the company implemented FASB 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

YEAR-END ENVIRONMENTAL REMEDIATION RESERVES
Millions of dollars



Reserves for environmental remediation were relatively unchanged from 2005. Reserves increased in 2005 due to the assumption of Unocal environmental liabilities.

long-lived assets and the liability can be reasonably estimated. The liability balance of approximately \$5.8 billion for asset retirement obligations at year-end 2006 related primarily to upstream and mining properties. Refer to Note 24 on page 82 for a discussion of the company's asset retirement obligations.

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 also to Note 24, on page 82, related to FAS 143 and the company's adoption in 2005 of FASB Interpretation No. (FIN) 47, *Accounting for Conditional Asset Retirement Obligations – An Interpretation of FASB Statement No. 143* (FIN 47), and the discussion of "Environmental Matters" on page 43.

Income Taxes The company calculates its income tax expense and liabilities quarterly. 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 calculated. The U.S. federal income tax liabilities have been settled through 1996 for Chevron Corporation, 1997 for Unocal Corporation (Unocal) and 2001 for Texaco Corporation (Texaco). California franchise tax liabilities have been settled through 1991 for Chevron, 1998 for Unocal 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.

Global Operations Chevron and its affiliates conduct business activities in approximately 180 countries. Besides the United States, the company and its affiliates have significant operations in the following countries: Angola, Argentina, Australia, Azerbaijan, Bangladesh, Brazil, Cambodia, Canada, Chad, China, Colombia, Democratic Republic of the Congo, Denmark, France, India, Indonesia, Kazakhstan, Myanmar, the Netherlands, Nigeria, Norway, the Partitioned Neutral Zone between Kuwait and Saudi Arabia, the Philippines, Republic of the Congo, Singapore, South Africa, South Korea, Thailand, Trinidad and Tobago, the United Kingdom, Venezuela, and Vietnam.

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 governments to increase public ownership of the company's partially or

wholly owned businesses or assets or to impose additional taxes or royalties on the company's operations or both.

In certain locations, 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, acts of violence or strained relations between a 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.

Suspended Wells The company suspends the costs of exploratory wells pending a final determination of the commercial potential of the related crude oil and natural gas fields. The ultimate disposition of these well costs is dependent on the results of future drilling activity or development decisions or both. At December 31, 2006, the company had approximately \$1.2 billion of suspended exploratory wells included in properties, plant and equipment, an increase of \$130 million from 2005 and an increase of \$568 million from 2004. More than \$300 million of suspended wells were added at the time of the Unocal acquisition in August 2005.

The future trend of the company's exploration expenses can be affected by amounts associated with well write-offs, including wells that had been previously suspended pending determination as to whether the well had found reserves that could be classified as proved. The effect on exploration expenses in future periods of the \$1.2 billion of suspended wells at year-end 2006 is uncertain pending future activities, including normal project evaluation and additional drilling.

Refer to Note 20, beginning on page 71, for additional discussion of suspended wells.

Equity Redetermination For oil and gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated crude oil and natural 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 Chevron'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. For this range of settlement, Chevron estimates its maximum possible net before-tax liability at approximately \$200 million, and the possible maximum net amount that could be owed to Chevron is estimated at about \$150 million. The timing of the settlement and the exact amount within this range of estimates are uncertain.

Other Contingencies Chevron receives claims from and submits claims to customers, trading partners, U.S. federal, state and local regulatory bodies, 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.

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 or at non-Chevron 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 or remedial work or both to meet current standards.

Using definitions and guidelines established by the American Petroleum Institute, Chevron estimated its worldwide environmental spending in 2006 at approximately \$2.2 billion for its consolidated companies. Included in these expenditures were approximately \$870 million of environmental capital expenditures and \$1.3 billion of costs associated with the prevention, control, abatement or elimination of hazardous substances and pollutants from operating, closed or divested sites, and the abandonment and restoration of sites.

For 2007, total worldwide environmental capital expenditures are estimated at \$1.2 billion. 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 these "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 crude oil and natural 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," beginning on page 92, for the changes in these estimates for the three years ending December 31, 2006, and to Table VII, "Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves" on page 100 for estimates of proved-reserve values for each of the three years ending December 31, 2004 through 2006, which were based on year-end prices at the time. Note 1 to the Consolidated Financial Statements, beginning on page 56, 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 Properties, Plant and Equipment and Investments in Affiliates," on page 45, 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 56. 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 obligations and expense is based on a number of actuarial assumptions. Two critical assumptions are the expected long-term rate of return on 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 benefits for qualifying retired employees and which are not funded, critical assumptions in determining OPEB obligations and expense are the discount rate and the assumed health care cost-trend rates.

Note 21, beginning on page 72, includes information on the funded status of the company's pension and OPEB plans at the end of 2006 and 2005, the components of pension and OPEB expense for the three years ending December 31, 2006, and the underlying assumptions for those periods. The note also presents the incremental impact of recording the funded status of each of the company's pension and OPEB plans at year-end 2006 under the provisions of FASB Statement No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R* (FAS 158).

Pension and OPEB expense is recorded on the Consolidated Statement of Income in "Operating expenses" or "Selling, general and administrative expenses" and applies to all business segments. With the adoption of FAS 158, the year-end 2006 funded status, measured as the difference between plan assets and obligations, of each of the company's pension and OPEB plans is recognized on the Consolidated Balance Sheet. The funded status of overfunded pension plans is recorded as a long-term asset in "Deferred charges and other assets." The funded status of underfunded or unfunded pension and OPEB plans is recorded in "Accrued liabilities" or "Reserves for employee benefit plans." Amounts yet to be

recognized as components of pension or OPEB expense are recorded in "Accumulated other comprehensive income."

To estimate the long-term rate of return on pension assets, the company uses a 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 factors. Asset allocations are periodically 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. The expected long-term rate of return on U.S. pension plan assets, which account for 70 percent of the company's pension plan assets, has remained at 7.8 percent since 2002. For the 10 years ending December 31, 2006, actual asset returns averaged 9.7 percent for this plan.

The year-end market-related value of assets of the major U.S. pension plan used in the determination of pension expense was based on the market value 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 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. For other plans, market value of assets as of the measurement date is used in calculating the pension expense.

The discount rate assumptions used to determine U.S. and international pension and postretirement benefit plan obligations and expense reflect the prevailing rates available on high-quality fixed-income debt instruments. At December 31, 2006, the company selected a 5.8 percent discount rate for the major U.S. pension and postretirement plans. This rate was selected based on Moody's Aa Corporate Bond Index and a cash flow analysis that matched estimated future benefit payments to the Citigroup Pension Discount Yield Curve as of year-end 2006. The discount rates at the end of 2005 and 2004 were 5.5 percent and 5.8 percent, respectively.

An increase in the expected long-term return on plan assets or the discount rate would reduce pension plan expense, and vice versa. Total pension expense for 2006 was approximately \$585 million. As an indication of the sensitivity of pension expense to the long-term rate of return assumption, a 1 percent increase in the expected rate of return on assets of the company's primary U.S. pension plan would have reduced total pension plan expense for 2006 by approximately \$60 million. A 1 percent increase in the discount rate for this same plan, which accounted for about 60 percent of the companywide pension obligation, would have reduced total pension plan expense for 2006 by approximately \$160 million.

An increase in the discount rate would decrease pension obligation, thus changing the funded status of a plan recorded on the Consolidated Balance Sheet. The total pen-

sion liability on the Consolidated Balance Sheet at December 31, 2006, for underfunded plans was approximately \$1.7 billion. As an indication of the sensitivity of pension liabilities to the discount rate assumption, a 0.25 percent increase in the discount rate applied to the company's primary U.S. pension plan would have reduced the plan obligation by approximately \$275 million, which would have changed the plan's funded status from underfunded to overfunded, resulting in a pension asset of about \$250 million. Other plans would be less underfunded as discount rates increase. 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.

In 2006, the company's pension plan contributions were approximately \$450 million (approximately \$225 million to the U.S. plans). In 2007, the company estimates contributions will be approximately \$500 million. Actual contribution amounts are dependent upon plan-investment results, changes in pension obligations, regulatory requirements and other economic factors. Additional funding may be required if investment returns are insufficient to offset increases in plan obligations.

For the company's OPEB plans, expense for 2006 was about \$230 million and the total liability, which reflected the underfunded status of the plans at the end of 2006, was \$3.3 billion.

As an indication of discount rate sensitivity to the determination of OPEB expense in 2006, a 1 percent increase in the discount rate for the company's primary U.S. OPEB plan, which accounted for about 75 percent of the company-wide OPEB expense, would have decreased OPEB expense by approximately \$25 million. A 0.25 percent increase in the discount rate for the same plan, which accounted for about 90 percent of the companywide OPEB liabilities, would have decreased total OPEB liabilities at the end of 2006 by approximately \$70 million.

For the main U.S. postretirement medical plan, the annual increase to company contributions is limited to 4 percent per year. The cap becomes effective in the year of retirement for pre-Medicare-eligible employees retiring on or after January 1, 2005. The cap was effective as of January 1, 2005, for pre-Medicare-eligible employees retiring before that date and all Medicare-eligible retirees. For active employees and retirees under age 65 whose claims experiences are combined for rating purposes, the assumed health care cost-trend rates start with 9 percent in 2007 and gradually drop to 5 percent for 2011 and beyond. As an indication of the health care cost-trend rate sensitivity to the determination of OPEB expense in 2006, a 1 percent increase in the rates for the main U.S. postretirement medical plan, which accounted for about 90 percent of the companywide OPEB obligations, would have increased OPEB expense \$8 million.

Differences between the various assumptions used to determine expense and the funded status of each plan and actual experience are not included in benefit plan costs in the year the difference occurs. Instead, the differences are included in actuarial gain/loss and unamortized amounts have been reflected in "Accumulated other comprehensive

loss" on the Consolidated Balance Sheet. Refer to Note 21, beginning on page 72, for information on the \$2.6 billion of actuarial losses recorded by the company as of December 31, 2006; a description of the method used to amortize those costs; and an estimate of the costs to be recognized in expense during 2007.

Impairment of Properties, Plant and Equipment and Investments in Affiliates The company assesses its properties, 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 crude oil and natural 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, production profiles, 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.

No major impairments of PP&E were recorded for the three years ending December 31, 2006. An estimate as to the sensitivity to earnings for these periods if other assumptions had been used in 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 or 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 is made to sell such assets. That is, the assets would be impaired if they are classified as held-for-sale and the estimated proceeds from the sale, less costs to sell, are less than the assets' associated carrying values.

Business Combinations – Purchase-Price Allocation Accounting for business combinations requires the allocation of the company's purchase price to the various assets and liabilities of the acquired business at their respective fair values. The company uses all available information to make these fair value determinations, and for major acquisitions, may hire an independent appraisal firm to assist in making fair value estimates. In some instances, assumptions with respect to the timing and amount of future revenues and expenses associated with an asset might have to be used in determining its fair value. Actual timing and amount of net cash flows from revenues and expenses related to that asset over time may differ materially from those initial estimates, and if the timing is delayed significantly or if the net cash flows decline significantly, the asset could become impaired.

Goodwill Goodwill acquired in a business combination is not subject to amortization. As required by FASB Statement No. 142, *Goodwill and Other Intangible Assets*, the company tests such goodwill at the reporting unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The goodwill arising from the Unocal acquisition is described in more detail in Note 2, beginning on page 58.

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 section for the effect on earnings from losses associated with certain litigation and environmental remediation and tax matters for the three years ended December 31, 2006.

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

NEW ACCOUNTING STANDARDS

EITF Issue No. 04-6, Accounting for Stripping Costs Incurred During Production in the Mining Industry (Issue 04-6) In March 2005, the FASB ratified the earlier Emerging Issues Task Force (EITF) consensus on Issue 04-6, which was adopted by the company on January 1, 2006. Stripping costs are costs of removing overburden and other waste materials to access mineral deposits. The consensus calls for stripping costs incurred once a mine goes into production to be treated as variable production costs that should be considered a component of mineral inventory cost subject to Accounting Research Bulletin (ARB) No. 43, *Restatement and Revision of Accounting Research Bulletins*. Adoption of this accounting for the company's coal, oil sands and other mining operations resulted in a \$19 million reduction of retained earnings as of January 1, 2006.

FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes – An Interpretation of FASB Statement No. 109 (FIN 48) In July 2006, the FASB issued FIN 48, which became effective for the company on January 1, 2007. This interpretation clarifies the accounting for income tax benefits that are uncertain in nature. Under FIN 48, a company will recognize a tax benefit in the financial statements for an uncertain tax position only if management's assessment is that its position is "more likely than not" (i.e., a greater than 50 percent likelihood) to be upheld on audit based only on the technical merits of the tax position. This accounting interpretation also provides guidance on measurement methodology, derecognition thresholds, financial statement classification and disclosures, interest and penalties recognition, and accounting for the cumulative-effect adjustment. The new interpretation is intended to provide better financial statement comparability among companies.

Required annual disclosures include a tabular reconciliation of unrecognized tax benefits at the beginning and end of the period; the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate; the amounts of interest and penalties recognized in the financial statements; any expected significant impacts from unrecognized tax benefits on the financial statements over the subsequent 12-month reporting period; and a description of the tax years remaining to be examined in major tax jurisdictions.

As a result of the implementation of FIN 48, the company expects to recognize an increase in the liability for unrecognized tax benefits and associated interest and penalties as of January 1, 2007. In connection with this increase in liability, the company estimates retained earnings at the beginning of 2007 will be reduced by \$250 million or less. The amount of the liability and impact on retained earnings will depend in part on clarification expected to be issued by the FASB related to the criteria for determining the date of ultimate settlement with a tax authority.

FASB Statement No. 157, Fair Value Measurements (FAS 157) In September 2006, the FASB issued FAS 157, which will become effective for the company on January 1, 2008. This standard defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. FAS 157 does not require any new fair value measurements but would apply to assets and liabilities that are required to be recorded at fair value under other accounting standards. The impact, if any, to the company from the adoption of FAS 157 in 2008 will depend on the company's assets and liabilities at that time that are required to be measured at fair value.

FASB Statement No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106 and 132(R) (FAS 158) In September 2006, the FASB issued FAS 158, which was adopted by the company on December 31, 2006. Refer to Note 21, beginning on page 72, for additional information.

QUARTERLY RESULTS AND STOCK MARKET DATA

Unaudited

Millions of dollars, except per-share amounts	2006				2005			
	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 ^{1,2}	\$ 46,238	\$ 52,977	\$ 52,153	\$ 53,524	\$ 52,457	\$ 53,429	\$ 47,265	\$ 40,490
Income from equity affiliates	1,079	1,080	1,113	983	1,110	871	861	889
Other income	429	155	270	117	227	156	217	228
TOTAL REVENUES AND OTHER INCOME	47,746	54,212	53,536	54,624	53,794	54,456	48,343	41,607
COSTS AND OTHER DEDUCTIONS								
Purchased crude oil and products ²	27,658	32,076	32,747	35,670	34,246	36,101	31,130	26,491
Operating expenses	4,092	3,650	3,835	3,047	3,819	3,190	2,713	2,469
Selling, general and administrative expenses	1,203	1,428	1,207	1,255	1,340	1,337	1,152	999
Exploration expenses	547	284	265	268	274	177	139	153
Depreciation, depletion and amortization	1,988	1,923	1,807	1,788	1,725	1,534	1,320	1,334
Taxes other than on income ¹	5,533	5,403	5,153	4,794	5,063	5,282	5,311	5,126
Interest and debt expense	92	104	121	134	135	136	104	107
Minority interests	2	20	22	26	33	24	18	21
TOTAL COSTS AND OTHER DEDUCTIONS	41,115	44,888	45,157	46,982	46,635	47,781	41,887	36,700
INCOME BEFORE INCOME TAX EXPENSE	6,631	9,324	8,379	7,642	7,159	6,675	6,456	4,907
INCOME TAX EXPENSE	2,859	4,307	4,026	3,646	3,015	3,081	2,772	2,230
NET INCOME	\$ 3,772	\$ 5,017	\$ 4,353	\$ 3,996	\$ 4,144	\$ 3,594	\$ 3,684	\$ 2,677
PER-SHARE OF COMMON STOCK								
INCOME FROM CONTINUING OPERATIONS								
– BASIC	\$ 1.75	\$ 2.30	\$ 1.98	\$ 1.81	\$ 1.88	\$ 1.65	\$ 1.77	\$ 1.28
– DILUTED	\$ 1.74	\$ 2.29	\$ 1.97	\$ 1.80	\$ 1.86	\$ 1.64	\$ 1.76	\$ 1.28
NET INCOME								
– BASIC	\$ 1.75	\$ 2.30	\$ 1.98	\$ 1.81	\$ 1.88	\$ 1.65	\$ 1.77	\$ 1.28
– DILUTED	\$ 1.74	\$ 2.29	\$ 1.97	\$ 1.80	\$ 1.86	\$ 1.64	\$ 1.76	\$ 1.28
DIVIDENDS	\$ 0.52	\$ 0.52	\$ 0.52	\$ 0.45	\$ 0.45	\$ 0.45	\$ 0.45	\$ 0.40
COMMON STOCK PRICE RANGE – HIGH	\$ 75.97	\$ 67.85	\$ 62.88	\$ 62.21	\$ 64.45	\$ 65.77	\$ 59.34	\$ 62.08
– LOW	\$ 62.94	\$ 60.88	\$ 56.78	\$ 54.08	\$ 55.75	\$ 56.36	\$ 50.51	\$ 50.55
¹ Includes excise, value-added and other similar taxes:	\$ 2,498	\$ 2,522	\$ 2,416	\$ 2,115	\$ 2,173	\$ 2,268	\$ 2,162	\$ 2,116
² Includes amounts for buy/sell contracts:	\$ –	\$ –	\$ –	\$ 6,725	\$ 5,897	\$ 6,588	\$ 5,962	\$ 5,375

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 23, 2007, stockholders of record numbered approximately 223,000. There are no restrictions on the company's ability to pay dividends.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

To the Stockholders of Chevron Corporation

Management of Chevron is responsible for preparing the accompanying Consolidated Financial Statements and the related information appearing in this report. 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 judgment.


As stated in its report included herein, the independent registered public accounting firm of PricewaterhouseCoopers LLP has audited the company's consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States).

The Board of Directors of Chevron has an Audit Committee composed of directors who are not officers or employees of the company. The Audit Committee meets regularly with members of management, the internal auditors and the independent registered public accounting firm to review accounting, internal control, auditing and financial reporting matters. Both the internal auditors and the independent registered public accounting firm have free and direct access to the Audit Committee without the presence of management.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). The company's management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of its internal control over financial reporting based on the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, the company's management concluded that its internal control over financial reporting was effective as of December 31, 2006.

The company management's assessment of the effectiveness of its internal control over financial reporting as of December 31, 2006, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.



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

February 28, 2007



STEPHEN J. CROWE
Vice President
and Chief Financial Officer



MARK A. HUMPHREY
Vice President
and Comptroller

To the Stockholders and the Board of Directors of Chevron Corporation:

We have completed integrated audits of Chevron Corporation's consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

CONSOLIDATED FINANCIAL STATEMENTS

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, shareholders' equity and cash flows present fairly, in all material respects, the financial position of Chevron Corporation and its subsidiaries at December 31, 2006, and December 31, 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements 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 14 to the Consolidated Financial Statements, the Company changed its method of accounting for buy/sell contracts on April 1, 2006.

As Discussed in Note 21 to the Consolidated Financial Statements, the Company changed its method of accounting for defined benefit pension and other postretirement plans on December 31, 2006.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial

reporting as of December 31, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PriceWaterhouseCoopers LLP

San Francisco, California
February 28, 2007

CONSOLIDATED STATEMENT OF INCOME

Millions of dollars, except per-share amounts

	Year ended December 31		
	2006	2005	2004
REVENUES AND OTHER INCOME			
Sales and other operating revenues ^{1,2}	\$ 204,892	\$ 193,641	\$ 150,865
Income from equity affiliates	4,255	3,731	2,582
Other income	971	828	1,853
TOTAL REVENUES AND OTHER INCOME	210,118	198,200	155,300
COSTS AND OTHER DEDUCTIONS			
Purchased crude oil and products ²	128,151	127,968	94,419
Operating expenses	14,624	12,191	9,832
Selling, general and administrative expenses	5,093	4,828	4,557
Exploration expenses	1,364	743	697
Depreciation, depletion and amortization	7,506	5,913	4,935
Taxes other than on income ¹	20,883	20,782	19,818
Interest and debt expense	451	482	406
Minority interests	70	96	85
TOTAL COSTS AND OTHER DEDUCTIONS	178,142	173,003	134,749
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	31,976	25,197	20,551
INCOME TAX EXPENSE	14,838	11,098	7,517
INCOME FROM CONTINUING OPERATIONS	17,138	14,099	13,034
INCOME FROM DISCONTINUED OPERATIONS	—	—	294
NET INCOME	\$ 17,138	\$ 14,099	\$ 13,328
PER-SHARE OF COMMON STOCK³			
INCOME FROM CONTINUING OPERATIONS			
– BASIC	\$ 7.84	\$ 6.58	\$ 6.16
– DILUTED	\$ 7.80	\$ 6.54	\$ 6.14
INCOME FROM DISCONTINUED OPERATIONS			
– BASIC	\$ —	\$ —	\$ 0.14
– DILUTED	\$ —	\$ —	\$ 0.14
NET INCOME			
– BASIC	\$ 7.84	\$ 6.58	\$ 6.30
– DILUTED	\$ 7.80	\$ 6.54	\$ 6.28
¹ Includes excise, value-added and other similar taxes:	\$ 9,551	\$ 8,719	\$ 7,968
² Includes amounts in revenues for buy/sell contracts; associated costs are in "Purchased crude oil and products." Refer also to Note 14, on page 67.	\$ 6,725	\$ 23,822	\$ 18,650
³ All periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.			

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Millions of dollars

	Year ended December 31		
	2006	2005	2004
NET INCOME	\$ 17,138	\$ 14,099	\$ 13,328
Currency translation adjustment			
Unrealized net change arising during period	55	(5)	36
Unrealized holding (loss) gain on securities			
Net (loss) gain arising during period	(88)	(32)	35
Reclassification to net income of net realized (gain)	–	–	(44)
Total	(88)	(32)	(9)
Net derivatives gain (loss) on hedge transactions			
Net gain (loss) arising during period			
Before income taxes	2	(242)	(8)
Income taxes	6	89	(1)
Reclassification to net income of net realized gain (loss)			
Before income taxes	95	34	–
Income taxes	(36)	(12)	–
Total	67	(131)	(9)
Minimum pension liability adjustment			
Before income taxes	(88)	89	719
Income taxes	50	(31)	(247)
Total	(38)	58	472
OTHER COMPREHENSIVE (LOSS) GAIN, NET OF TAX	(4)	(110)	490
COMPREHENSIVE INCOME	\$ 17,134	\$ 13,989	\$ 13,818

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET

Millions of dollars, except per-share amounts

	At December 31	
	2006	2005
ASSETS		
Cash and cash equivalents	\$ 10,493	\$ 10,043
Marketable securities	953	1,101
Accounts and notes receivable (less allowance: 2006 – \$175; 2005 – \$156)	17,628	17,184
Inventories:		
Crude oil and petroleum products	3,586	3,182
Chemicals	258	245
Materials, supplies and other	812	694
Total inventories	4,656	4,121
Prepaid expenses and other current assets	2,574	1,887
TOTAL CURRENT ASSETS	36,304	34,336
Long-term receivables, net	2,203	1,686
Investments and advances	18,552	17,057
Properties, plant and equipment, at cost	137,747	127,446
Less: Accumulated depreciation, depletion and amortization	68,889	63,756
Properties, plant and equipment, net	68,858	63,690
Deferred charges and other assets	2,088	4,428
Goodwill	4,623	4,636
TOTAL ASSETS	\$ 132,628	\$ 125,833
LIABILITIES AND STOCKHOLDERS' EQUITY		
Short-term debt	\$ 2,159	\$ 739
Accounts payable	16,675	16,074
Accrued liabilities	4,546	3,690
Federal and other taxes on income	3,626	3,127
Other taxes payable	1,403	1,381
TOTAL CURRENT LIABILITIES	28,409	25,011
Long-term debt	7,405	11,807
Capital lease obligations	274	324
Deferred credits and other noncurrent obligations	11,000	10,507
Noncurrent deferred income taxes	11,647	11,262
Reserves for employee benefit plans	4,749	4,046
Minority interests	209	200
TOTAL LIABILITIES	63,693	63,157
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; 2,442,676,580 shares issued at December 31, 2006 and 2005)	1,832	1,832
Capital in excess of par value	14,126	13,894
Retained earnings	68,464	55,738
Notes receivable – key employees	(2)	(3)
Accumulated other comprehensive loss	(2,636)	(429)
Deferred compensation and benefit plan trust	(454)	(486)
Treasury stock, at cost (2006 – 278,118,341 shares; 2005 – 209,989,910 shares)	(12,395)	(7,870)
TOTAL STOCKHOLDERS' EQUITY	68,935	62,676
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	\$ 132,628	\$ 125,833

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

Millions of dollars

	Year ended December 31		
	2006	2005	2004
OPERATING ACTIVITIES			
Net income	\$ 17,138	\$ 14,099	\$ 13,328
Adjustments			
Depreciation, depletion and amortization	7,506	5,913	4,935
Dry hole expense	520	226	286
Distributions less than income from equity affiliates	(979)	(1,304)	(1,422)
Net before-tax gains on asset retirements and sales	(229)	(134)	(1,882)
Net foreign currency effects	259	62	60
Deferred income tax provision	614	1,393	(224)
Net decrease (increase) in operating working capital	1,044	(54)	430
Minority interest in net income	70	96	85
Increase in long-term receivables	(900)	(191)	(60)
Decrease (increase) in other deferred charges	232	668	(69)
Cash contributions to employee pension plans	(449)	(1,022)	(1,643)
Other	(503)	353	866
NET CASH PROVIDED BY OPERATING ACTIVITIES	24,323	20,105	14,690
INVESTING ACTIVITIES			
Cash portion of Unocal acquisition, net of Unocal cash received	—	(5,934)	—
Capital expenditures	(13,813)	(8,701)	(6,310)
Repayment of loans by equity affiliates	463	57	1,790
Proceeds from asset sales	989	2,681	3,671
Net sales (purchases) of marketable securities	142	336	(450)
Advances to equity affiliate	—	—	(2,200)
NET CASH USED FOR INVESTING ACTIVITIES	(12,219)	(11,561)	(3,499)
FINANCING ACTIVITIES			
Net (payments) borrowings of short-term obligations	(677)	(109)	114
Repayments of long-term debt and other financing obligations	(2,224)	(966)	(1,398)
Cash dividends – common stock	(4,396)	(3,778)	(3,236)
Dividends paid to minority interests	(60)	(98)	(41)
Net purchases of treasury shares	(4,491)	(2,597)	(1,645)
Redemption of preferred stock of subsidiaries	—	(140)	(18)
Proceeds from issuances of long-term debt	—	20	—
NET CASH USED FOR FINANCING ACTIVITIES	(11,848)	(7,668)	(6,224)
EFFECT OF EXCHANGE RATE CHANGES			
ON CASH AND CASH EQUIVALENTS	194	(124)	58
NET CHANGE IN CASH AND CASH EQUIVALENTS	450	752	5,025
CASH AND CASH EQUIVALENTS AT JANUARY 1	10,043	9,291	4,266
CASH AND CASH EQUIVALENTS AT DECEMBER 31	\$ 10,493	\$ 10,043	\$ 9,291

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

Shares in thousands; amounts in millions of dollars

	2006		2005		2004	
	Shares	Amount	Shares	Amount	Shares	Amount
PREFERRED STOCK	—	\$ —	—	\$ —	—	\$ —
COMMON STOCK						
Balance at January 1	2,442,677	\$ 1,832	2,274,032	\$ 1,706	2,274,042	\$ 1,706
Shares issued for Unocal acquisition	—	—	168,645	126	—	—
Conversion of Texaco Inc. acquisition	—	—	—	—	(10)	—
BALANCE AT DECEMBER 31	2,442,677	\$ 1,832	2,442,677	\$ 1,832	2,274,032	\$ 1,706
CAPITAL IN EXCESS OF PAR						
Balance at January 1		\$ 13,894		\$ 4,160		\$ 4,002
Shares issued for Unocal acquisition		—		9,585		—
Treasury stock transactions		232		149		158
BALANCE AT DECEMBER 31		\$ 14,126		\$ 13,894		\$ 4,160
RETAINED EARNINGS						
Balance at January 1		\$ 55,738		\$ 45,414		\$ 35,315
Net income		17,138		14,099		13,328
Cash dividends on common stock		(4,396)		(3,778)		(3,236)
Adoption of EITF 04-6, "Accounting for Stripping Costs Incurred during Production in the Mining Industry"		(19)		—		—
Tax benefit from dividends paid on unallocated ESOP shares and other		3		3		7
BALANCE AT DECEMBER 31		\$ 68,464		\$ 55,738		\$ 45,414
NOTES RECEIVABLE – KEY EMPLOYEES		\$ (2)		\$ (3)		\$ —
ACCUMULATED OTHER COMPREHENSIVE LOSS						
Currency translation adjustment						
Balance at January 1		\$ (145)		\$ (140)		\$ (176)
Change during year		55		(5)		36
Balance at December 31		\$ (90)		\$ (145)		\$ (140)
Pension and other postretirement benefit plans						
Balance at January 1		\$ (344)		\$ (402)		\$ (874)
Change to minimum pension liability during year		(38)		58		472
Adoption of FAS 158, "Employers' Accounting for Defined Pension and Other Postretirement Plans"		(2,203)		—		—
Balance at December 31		\$ (2,585)		\$ (344)		\$ (402)
Unrealized net holding gain on securities						
Balance at January 1		\$ 88		\$ 120		\$ 129
Change during year		(88)		(32)		(9)
Balance at December 31		\$ —		\$ 88		\$ 120
Net derivatives gain (loss) on hedge transactions						
Balance at January 1		\$ (28)		\$ 103		\$ 112
Change during year		67		(131)		(9)
Balance at December 31		\$ 39		\$ (28)		\$ 103
BALANCE AT DECEMBER 31		\$ (2,636)		\$ (429)		\$ (319)
DEFERRED COMPENSATION AND BENEFIT PLAN TRUST						
DEFERRED COMPENSATION						
Balance at January 1		\$ (246)		\$ (367)		\$ (362)
Net reduction of ESOP debt and other		32		121		(5)
BALANCE AT DECEMBER 31		(214)		(246)		(367)
BENEFIT PLAN TRUST (COMMON STOCK)	14,168	(240)	14,168	(240)	14,168	(240)
BALANCE AT DECEMBER 31	14,168	\$ (454)	14,168	\$ (486)	14,168	\$ (607)
TREASURY STOCK AT COST						
Balance at January 1	209,990	\$ (7,870)	166,912	\$ (5,124)	135,747	\$ (3,317)
Purchases	80,369	(5,033)	52,013	(3,029)	42,607	(2,122)
Issuances – mainly employee benefit plans	(12,241)	508	(8,935)	283	(11,442)	315
BALANCE AT DECEMBER 31	278,118	\$ (12,395)	209,990	\$ (7,870)	166,912	\$ (5,124)
TOTAL STOCKHOLDERS' EQUITY AT DECEMBER 31		\$ 68,935		\$ 62,676		\$ 45,230

See accompanying Notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Millions of dollars, except per-share amounts

NOTE 1.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General Exploration and production (upstream) operations consist of exploring for, developing and producing crude oil and natural gas and also marketing natural gas. Refining, marketing and transportation (downstream) operations relate to refining crude oil into finished petroleum products; marketing crude oil and the many products derived from petroleum; and transporting crude oil, natural gas and petroleum products by pipeline, marine vessel, motor equipment and rail car. Chemical operations include the manufacture and marketing of commodity petrochemicals, plastics for industrial uses, and fuel and lubricant oil additives.

The company's Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in the United States of America. These require 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. Although 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 the company 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 and variable-interest entities in which the company is the primary beneficiary. Undivided interests in oil and gas joint ventures and certain other assets are consolidated on a proportionate basis. 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 events indicate 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 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 when appropriate 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 financial 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 does not 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 securities. Those investments that are part of the company's cash management portfolio and have original maturities of three months or less are reported as "Cash equivalents." The balance of the short-term investments is reported as "Marketable securities" and 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 crude oil and natural gas exploration and production activities. All costs for development wells, related plant and equipment, proved mineral interests in crude oil and natural 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 are also capitalized for exploratory wells that have found crude oil and natural gas reserves even if the reserves cannot be classified as proved when the drilling is completed, provided the exploratory well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. All other exploratory wells and costs are expensed. Refer to Note 20, beginning on page 71, for additional discussion of accounting for suspended exploratory well costs.

Long-lived assets to be held and used, including proved crude oil and natural gas properties, are assessed for possible impairment by comparing their carrying values with their associated 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 of or a physical change in an asset, and a more-likely-than-not expectation that a long-lived asset or asset group will be sold or otherwise disposed of significantly sooner than 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 crude oil and natural 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, development area, or field basis, as appropriate. In the refining, marketing, transportation and chemical areas, impairment reviews are generally done on the basis of a refinery, a plant, a marketing area or marketing assets by country. 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 of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the asset is considered impaired and adjusted to the lower value.

As required under Financial Accounting Standards Board (FASB) Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143), the fair value of a liability for an ARO 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. Refer also to Note 24, on page 82, relating to AROs.

Depreciation and depletion of all capitalized costs of proved crude oil and natural 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 mining assets are determined using the unit-of-production method as the proven 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 (including those for planned major maintenance projects), repairs and minor renewals to maintain facilities in operating condition are generally expensed as incurred. Major replacements and renewals are capitalized.

Goodwill Goodwill acquired in a business combination is not subject to amortization. As required by FASB Statement No. 142, *Goodwill and Other Intangible Assets*, the company tests such goodwill at the reporting unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The goodwill arising from the Unocal acquisition is described in more detail in Note 2, beginning on page 58.

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 or cleanups or both 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 crude oil, natural gas and mineral producing properties, a liability for an asset retire-

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

ment obligation is made, following FAS 143. Refer to Note 24, on page 82, for a discussion of FAS 143.

For federal Superfund sites and analogous sites under state laws, 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 gross amount of environmental liabilities is based on the company's best estimate of future costs using currently available technology and applying current regulations and 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 and 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 Chevron has an interest with other producers are generally recognized on the basis of the company's net working interest (entitlement method). Excise, value-added and other similar taxes assessed by a governmental authority on a revenue-producing transaction between a seller and a customer are presented on a gross basis. The associated amounts are shown as a footnote to the Consolidated Statement of Income on page 51. Refer to Note 14, on page 67, for a discussion of the accounting for buy/sell arrangements.

Stock Options and Other Share-Based Compensation Effective July 1, 2005, the company adopted the provisions of FASB Statement No. 123R, *Share-Based Payment* (FAS 123R), for its share-based compensation plans. The company previously accounted for these plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25), and related interpretations and disclosure requirements established by FASB Statement No. 123, *Accounting for Stock-Based Compensation* (FAS 123).

Refer to Note 22, beginning on page 77, for a description of the company's share-based compensation plans,

information related to awards granted under those plans and additional information on the company's adoption of FAS 123R.

The following table illustrates the effect on net income and earnings per share as if the company had applied the fair-value recognition provisions of FAS 123 to stock options, stock appreciation rights, performance units and restricted stock units for periods prior to adoption of FAS 123R and the actual effect on 2005 net income and earnings per share for periods after adoption of FAS 123R.

	Year ended December 31	
	2005	2004
Net income, as reported	\$ 14,099	\$ 13,328
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	81	42
Deduct: Total stock-based employee compensation expense determined under fair-valued-based method for awards, net of related tax effects ¹	(108)	(84)
Pro forma net income	\$ 14,072	\$ 13,286
Net income per share:²		
Basic – as reported	\$ 6.58	\$ 6.30
Basic – pro forma	\$ 6.56	\$ 6.28
Diluted – as reported	\$ 6.54	\$ 6.28
Diluted – pro forma	\$ 6.53	\$ 6.26

¹ Fair value determined using the Black-Scholes option-pricing model.

² Per-share amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

NOTE 2.

ACQUISITION OF UNOCAL CORPORATION

In August 2005, the company acquired Unocal Corporation (Unocal), an independent oil and gas exploration and production company. Unocal's principal upstream operations were in North America and Asia, including the Caspian region. Also located in Asia were Unocal's geothermal energy and electrical power businesses. Other activities included ownership interests in proprietary and common carrier pipelines, natural gas storage facilities and mining operations.

The aggregate purchase price of Unocal was approximately \$17,288. A third-party appraisal firm was engaged to assist the company in the process of determining the fair values of Unocal's tangible and intangible assets. The final purchase-price allocation to the assets and liabilities acquired was completed as of June 30, 2006.

NOTE 2. ACQUISITION OF UNOCAL CORPORATION - Continued

The acquisition was accounted for under the rules of FASB Statement No. 141, *Business Combinations*. The following table summarizes the final purchase-price allocation:

Current assets	\$ 3,573
Investments and long-term receivables	1,695
Properties	17,285
Goodwill	4,820
Other assets	2,174
Total assets acquired	29,547
Current liabilities	(2,364)
Long-term debt and capital leases	(2,392)
Deferred income taxes	(4,009)
Other liabilities	(3,494)
Total liabilities assumed	(12,259)
Net assets acquired	\$ 17,288

The \$4,820 of goodwill, which represents benefits of the acquisition that are additional to the fair values of the other net assets acquired, was assigned to the upstream segment. The goodwill is not deductible for tax purposes. The goodwill balance was reviewed for possible impairment as of June 30, 2006, according to the requirements of FASB Statement No. 142, *Goodwill and Other Intangible Assets*, to test goodwill for impairment on an annual basis. Goodwill was determined not to be impaired at that time, and no events have occurred subsequently that would necessitate an additional impairment review.

The following unaudited pro forma summary presents the results of operations as if the acquisition of Unocal had occurred at the beginning of each period:

	Year ended December 31	
	2005	2004
Sales and other operating revenues	\$ 198,762	\$ 158,471
Net income	14,967	14,164
Net income per share of common stock		
Basic	\$ 6.68	\$ 6.22
Diluted	\$ 6.64	\$ 6.19

The pro forma summary uses estimates and assumptions based on information available at the time. Management believes the estimates and assumptions to be reasonable; however, actual results may differ significantly from this pro forma financial information. The pro forma information does not reflect any synergistic savings that might be achieved from combining the operations and is not intended to reflect the actual results that would have occurred had the companies actually been combined during the periods presented.

NOTE 3.

INFORMATION RELATING TO THE CONSOLIDATED STATEMENT OF CASH FLOWS

	Year ended December 31		
	2006	2005	2004
Net decrease (increase) in operating working capital was composed of the following:			
Decrease (increase) in accounts and notes receivable	\$ 17	\$ (3,164)	\$ (2,515)
Increase in inventories	(536)	(968)	(298)
Increase in prepaid expenses and other current assets	(31)	(54)	(76)
Increase in accounts payable and accrued liabilities	1,246	3,851	2,175
Increase in income and other taxes payable	348	281	1,144
Net decrease (increase) in operating working capital	\$ 1,044	\$ (54)	\$ 430
Net cash provided by operating activities includes the following cash payments for interest and income taxes:			
Interest paid on debt (net of capitalized interest)	\$ 470	\$ 455	\$ 422
Income taxes	\$ 13,806	\$ 8,875	\$ 6,679
Net (purchases) sales of marketable securities consisted of the following gross amounts:			
Marketable securities purchased	\$ (1,271)	\$ (918)	\$ (1,951)
Marketable securities sold	1,413	1,254	1,501
Net sales (purchases) of marketable securities	\$ 142	\$ 336	\$ (450)

The Consolidated Statement of Cash Flows excludes the effects of noncash transactions. In October 2006, operating service agreements in Venezuela were converted to joint stock companies. Upon conversion, the company reclassified \$441 of long-term receivables, \$132 of accounts receivable and \$45 of properties, plant and equipment to investments in equity affiliates. Refer also to Note 21 on page 72 for the noncash effects associated with the implementation of FASB Statement No. 158, *Employers' Accounting for Defined Pension and Other Postretirement Plans*.

In accordance with the cash-flow classification requirements of FAS 123R, *Share-Based Payment*, the "Net decrease (increase) in operating working capital" includes reductions of \$94 and \$20 for excess income tax benefits associated with stock options exercised during 2006 and 2005, respectively. These amounts are offset by "Net purchases of treasury shares."

The "Net purchases of treasury shares" represents the cost of common shares acquired in the open market less the cost of shares issued for share-based compensation plans. Open-market purchases totaled \$5,033, \$3,029 and \$2,122 in 2006, 2005 and 2004, respectively.

NOTE 3. INFORMATION RELATING TO THE CONSOLIDATED STATEMENT OF CASH FLOWS – Continued

In May 2006, the company's investment in Dynegy Series C preferred stock was redeemed at its face value of \$400. Upon redemption of the preferred stock, the company recorded a before-tax gain of \$130 (\$87 after tax). The \$130 gain is included in the Consolidated Statement of Income as "Income from equity affiliates."

The 2005 "cash portion of Unocal acquisition, net of Unocal cash received" represents the purchase price, net of \$1,600 of cash received. The aggregate purchase price of Unocal was approximately \$17,288. Refer to Note 2, starting on page 58, for additional discussion of the Unocal acquisition.

The major components of "Capital expenditures" and the reconciliation of this amount to the reported capital and exploratory expenditures, including equity affiliates, presented in Management's Discussion and Analysis, beginning on page 26, are presented in the following table:

	Year ended December 31		
	2006	2005	2004
Additions to properties, plant and equipment*	\$12,800	\$ 8,154	\$ 5,798
Additions to investments	880	459	303
Current-year dry hole expenditures	400	198	228
Payments for other liabilities and assets, net	(267)	(110)	(19)
Capital expenditures	13,813	8,701	6,310
Expensed exploration expenditures	844	517	412
Assets acquired through capital lease obligations and other financing obligations	35	164	31
Capital and exploratory expenditures, excluding equity affiliates	14,692	9,382	6,753
Equity in affiliates' expenditures	1,919	1,681	1,562
Capital and exploratory expenditures, including equity affiliates	\$ 16,611	\$ 11,063	\$ 8,315

*Net of noncash additions of \$440 in 2006, \$435 in 2005 and \$212 in 2004.

NOTE 4.

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

Chevron U.S.A. Inc. (CUSA) is a major subsidiary of Chevron Corporation. CUSA and its subsidiaries manage and operate most of Chevron'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 Chevron. CUSA also holds Chevron's investments in the Chevron Phillips Chemical Company LLC (CPCChem) joint venture and Dynegy Inc. (Dynegy), which are accounted for using the equity method.

	Year ended December 31		
	2006	2005	2004
Sales and other operating revenues	\$ 146,447	\$ 138,296	\$ 108,351
Total costs and other deductions	138,494	132,180	102,180
Net income	5,399	4,693	4,773

	At December 31	
	2006	2005
Current assets	\$ 26,356	\$ 27,878
Other assets	23,200	20,611
Current liabilities	17,250	20,286
Other liabilities	11,501	12,897
Net equity	20,805	15,306
Memo: Total debt	\$ 6,020	\$ 8,353

NOTE 5.

SUMMARIZED FINANCIAL DATA – CHEVRON TRANSPORT CORPORATION LTD.

Chevron Transport Corporation Ltd. (CTC), incorporated in Bermuda, is an indirect, wholly owned subsidiary of Chevron Corporation. CTC is the principal operator of Chevron'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 Chevron companies. Chevron Corporation has fully and unconditionally 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 in the following table:

	Year ended December 31		
	2006	2005	2004
Sales and other operating revenues	\$ 692	\$ 640	\$ 660
Total costs and other deductions	602	509	495
Net income	119	113	160

	At December 31	
	2006	2005
Current assets	\$ 413	\$ 358
Other assets	345	283
Current liabilities	92	119
Other liabilities	250	243
Net equity	416	279

There were no restrictions on CTC's ability to pay dividends or make loans or advances at December 31, 2006.

NOTE 6.

STOCKHOLDERS' EQUITY

Retained earnings at December 31, 2006 and 2005, included approximately \$5,580 and \$5,000, respectively, for the company's share of undistributed earnings of equity affiliates.

At December 31, 2006, about 134 million shares of Chevron's common stock remained available for issuance from

the 160 million shares that were reserved for issuance under the Chevron Corporation Long-Term Incentive Plan (LTIP), as amended and restated, which was approved by the stockholders in 2004. In addition, approximately 503,000 shares remain available for issuance from the 800,000 shares of the company's common stock that were reserved for awards under the Chevron Corporation Non-Employee Directors' Equity Compensation and Deferral Plan (Non-Employee Directors' Plan), which was approved by stockholders in 2003. Refer to Note 25, on page 82, for a discussion of the company's common stock split in 2004.

NOTE 7.

FINANCIAL AND DERIVATIVE INSTRUMENTS

Commodity Derivative Instruments Chevron is exposed to market risks related to price volatility of crude oil, refined products, natural gas, natural gas liquids, liquefied natural gas and refinery feedstocks.

The company uses derivative commodity instruments to manage these exposures on a portion of its activity, including: firm commitments and anticipated transactions for the purchase, sale and storage of crude oil, refined products, natural gas, natural gas liquids, and feedstock for company refineries. The company also uses derivative commodity instruments for limited trading purposes.

The company uses International Swaps Dealers Association agreements to govern derivative contracts with certain counterparties to mitigate credit risk. Depending on the nature of the derivative transactions, 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 marked-to-market exposure represents the netting of the positive and negative exposures with that counterparty and is a reasonable measure of the company's credit risk exposure. The company also uses other netting agreements with certain counterparties with which it conducts significant transactions to mitigate credit risk.

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."

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 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."

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.

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."

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 \$5,131 and \$7,424 had estimated fair values of \$5,621 and \$7,945 at December 31, 2006 and 2005, respectively.

The company holds cash equivalents and marketable securities in U.S. and non-U.S. 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 \$9,200 and \$8,995 at December 31, 2006 and 2005, respectively. Of these balances, \$8,247 and \$7,894 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 1.4 years.

For the financial and derivative instruments discussed above, there was not a material change in market risk from that presented in 2005.

Fair values of other financial and derivative instruments at the end of 2006 and 2005 were not material.

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 finan-

NOTE 7. FINANCIAL AND DERIVATIVE INSTRUMENTS - Continued

cial 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, the company believes 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, requiring Letters of Credit is a principal method used to support sales to customers.

NOTE 8.

OPERATING SEGMENTS AND GEOGRAPHIC DATA

Although each subsidiary of Chevron is responsible for its own affairs, Chevron Corporation manages its investments in these subsidiaries and their affiliates. For this purpose, the investments are grouped as follows: upstream – exploration and production; downstream – refining, marketing and transportation; chemicals; and all other. The first three of these groupings represent the company's "reportable segments" and "operating segments" as defined in Financial Accounting Standards Board (FASB) Statement No. 131, *Disclosures About Segments of an Enterprise and Related Information* (FAS 131).

The segments are separately managed for investment purposes under a structure that includes "segment managers" who report to the company's "chief operating decision maker" (CODM) (terms as defined in FAS 131). The CODM is the company's Executive Committee, a committee of senior officers that includes the Chief Executive Officer and that, in turn, reports to the Board of Directors of Chevron Corporation.

The operating segments represent components of the company as described in FAS 131 terms that engage in activities (a) from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the CODM, which makes decisions about resources to be allocated to the segments and to assess their performance; and (c) for which discrete financial information is available.

Segment managers for the reportable segments are accountable directly to and maintain regular contact with the company's CODM to discuss the segment's operating activities and financial performance. The CODM approves annual capital and exploratory budgets at the reportable segment level, as well as reviews capital and exploratory funding for major projects and approves major changes to the annual capital and exploratory budgets. However, business-unit managers within the operating segments are directly responsible for decisions relating to project implementation and all other matters connected with daily operations. Company officers who are members of the Executive Committee also have individual

management responsibilities and participate in other committees for purposes other than acting as the CODM.

"All Other" activities include the company's interest in Dynegy, mining operations, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, alternative fuels, and technology companies.

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. Nonbillable costs remain at the corporate level in "All Other." After-tax segment income from continuing operations is presented in the following table:

	Year ended December 31		
	2006	2005	2004
Income From Continuing Operations			
Upstream			
United States	\$ 4,270	\$ 4,168	\$ 3,868
International	8,872	7,556	5,622
Total Upstream	13,142	11,724	9,490
Downstream			
United States	1,938	980	1,261
International	2,035	1,786	1,989
Total Downstream	3,973	2,766	3,250
Chemicals			
United States	430	240	251
International	109	58	63
Total Chemicals	539	298	314
Total Segment Income	17,654	14,788	13,054
All Other			
Interest expense	(312)	(337)	(257)
Interest income	380	266	129
Other	(584)	(618)	108
Income From Continuing Operations	17,138	14,099	13,034
Income From Discontinued Operations	–	–	294
Net Income	\$ 17,138	\$ 14,099	\$ 13,328

NOTE 8. OPERATING SEGMENTS AND GEOGRAPHIC DATA - Continued

Segment Assets Segment assets do not include intercompany investments or intercompany receivables. Segment assets at year-end 2006 and 2005 are as follows:

	At December 31	
	2006	2005
Upstream		
United States	\$ 20,727	\$ 19,006
International	51,844	46,501
Goodwill	4,623	4,636
Total Upstream	77,194	70,143
Downstream		
United States	13,482	12,273
International	22,892	22,294
Total Downstream	36,374	34,567
Chemicals		
United States	2,568	2,452
International	832	727
Total Chemicals	3,400	3,179
Total Segment Assets	116,968	107,889
All Other*		
United States	8,481	9,234
International	7,179	8,710
Total All Other	15,660	17,944
Total Assets – United States	45,258	42,965
Total Assets – International	82,747	78,232
Goodwill	4,623	4,636
Total Assets	\$ 132,628	\$ 125,833

*“All Other” assets consist primarily of worldwide cash, cash equivalents and marketable securities, real estate, information systems, the company’s investment in Dynegey, mining operations, power generation businesses, technology companies, and assets of the corporate administrative functions.

Segment Sales and Other Operating Revenues Operating segment sales and other operating revenues, including internal transfers, for the years 2006, 2005 and 2004 are presented in the following table. Products are transferred between operating segments at internal product values that approximate market prices.

Revenues for the upstream segment are derived primarily from the production and sale of crude oil and natural gas, as well as the sale of third-party production of natural gas. Revenues for the downstream 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. Revenues for the chemicals segment are derived primarily from the manufacture and sale of additives for lubricants and fuel. “All Other” activities include revenues from mining operations of coal and other minerals, power generation businesses, insurance operations, real estate activities, and technology companies.

Other than the United States, no single country accounted for 10 percent or more of the company’s total sales and other operating revenues in 2006.

	Year ended December 31		
	2006	2005	2004
Upstream			
United States	\$ 18,061	\$ 16,044	\$ 8,242
Intersegment	10,069	8,651	8,121
Total United States	28,130	24,695	16,363
International	14,560	10,190	7,246
Intersegment	17,139	13,652	10,184
Total International	31,699	23,842	17,430
Total Upstream	59,829	48,537	33,793
Downstream			
United States	69,367	73,721	57,723
Excise and other similar taxes	4,829	4,521	4,147
Intersegment	533	535	179
Total United States	74,729	78,777	62,049
International	91,325	83,223	67,944
Excise and other similar taxes	4,657	4,184	3,810
Intersegment	37	14	87
Total International	96,019	87,421	71,841
Total Downstream	170,748	166,198	133,890
Chemicals			
United States	372	343	347
Excise and other similar taxes	2	–	–
Intersegment	243	241	188
Total United States	617	584	535
International	959	760	747
Excise and other similar taxes	63	14	11
Intersegment	160	131	107
Total International	1,182	905	865
Total Chemicals	1,799	1,489	1,400
All Other			
United States	653	597	551
Intersegment	584	514	431
Total United States	1,237	1,111	982
International	44	44	97
Intersegment	23	26	16
Total International	67	70	113
Total All Other	1,304	1,181	1,095
Segment Sales and Other Operating Revenues			
United States	104,713	105,167	79,929
International	128,967	112,238	90,249
Total Segment Sales and Other Operating Revenues	233,680	217,405	170,178
Elimination of intersegment sales	(28,788)	(23,764)	(19,313)
Total Sales and Other Operating Revenues*	\$ 204,892	\$ 193,641	\$ 150,865

*Includes buy/sell contracts of \$6,725 in 2006, \$23,822 in 2005 and \$18,650 in 2004. Substantially all of the amounts in each period relates to the downstream segment. Refer to Note 14, on page 67, for a discussion of the company’s accounting for buy/sell contracts.

NOTE 8. OPERATING SEGMENTS AND GEOGRAPHIC DATA - Continued

Segment Income Taxes Segment income tax expenses for the years 2006, 2005 and 2004 are as follows:

	Year ended December 31		
	2006	2005	2004
Upstream			
United States	\$ 2,668	\$ 2,330	\$ 2,308
International	10,987	8,440	5,041
Total Upstream	13,655	10,770	7,349
Downstream			
United States	1,162	575	739
International	586	576	442
Total Downstream	1,748	1,151	1,181
Chemicals			
United States	213	99	47
International	30	25	17
Total Chemicals	243	124	64
All Other	(808)	(947)	(1,077)
Income Tax Expense From Continuing Operations*	\$ 14,838	\$ 11,098	\$ 7,517

*Income tax expense of \$100 related to discontinued operations for 2004 is not included.

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 12, beginning on page 65. Information related to properties, plant and equipment by segment is contained in Note 13, on page 67.

NOTE 9.

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	
	2006	2005
Upstream	\$ 461	\$ 442
Downstream	896	837
Total	1,357	1,279
Less: Accumulated amortization	813	745
Net capitalized leased assets	\$ 544	\$ 534

Rental expenses incurred for operating leases during 2006, 2005 and 2004 were as follows:

	Year ended December 31		
	2006	2005	2004
Minimum rentals	\$ 2,326	\$ 2,102	\$ 2,093
Contingent rentals	6	6	7
Total	2,332	2,108	2,100
Less: Sublease rental income	33	43	40
Net rental expense	\$ 2,299	\$ 2,065	\$ 2,060

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 up to 25 years, and 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, 2006, the estimated future minimum lease payments (net of noncancelable sublease rentals) under operating and capital leases, which at inception had a non-cancelable term of more than one year, were as follows:

	At December 31	
	Operating Leases	Capital Leases
Year: 2007	\$ 509	\$ 91
2008	507	80
2009	477	81
2010	390	59
2011	311	57
Thereafter	864	520
Total	\$ 3,058	\$ 888
Less: Amounts representing interest and executory costs		(262)
Net present values		626
Less: Capital lease obligations included in short-term debt		(352)
Long-term capital lease obligations		\$ 274

NOTE 10.

RESTRUCTURING AND REORGANIZATION COSTS

In connection with the Unocal acquisition, the company implemented a restructuring and reorganization program as part of the effort to capture the synergies of the combined companies by eliminating redundant operations, consolidating offices and facilities, and sharing common services and functions.

As part of the restructuring and reorganization, approximately 600 employees were eligible for severance payments. Most of the associated positions are in the United States and relate primarily to corporate and upstream executive and administrative functions. By year-end 2006, the program was substantially complete.

NOTE 10. RESTRUCTURING AND REORGANIZATION COSTS - Continued

An accrual of \$106 was established as part of the purchase-price allocation for Unocal. The \$11 balance at year-end 2006 was classified as a current liability on the Consolidated Balance Sheet. Activity for this accrual is shown in the table below.

<i>Amounts before tax</i>	2006	2005
Balance at January 1	\$ 44	\$ –
Additions/adjustments	(14)	106
Payments	(19)	(62)
Balance at December 31	\$ 11	\$ 44

Shown in the table below is the activity for the company's liability related to various other reorganizations and restructurings across several businesses and corporate departments. The \$17 balance at year-end 2006 was also classified as a current liability on the Consolidated Balance Sheet. The associated charges or credits during the periods were categorized as "Operating expenses" or "Selling, general and administrative expenses" on the Consolidated Statement of Income.

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

<i>Amounts before tax</i>	2006	2005
Balance at January 1	\$ 47	\$ 119
Additions/adjustments	(7)	(10)
Payments	(23)	(62)
Balance at December 31	\$ 17	\$ 47

NOTE 11.
ASSETS HELD FOR SALE AND DISCONTINUED OPERATIONS

At December 31, 2004, the company classified \$162 of net properties, plant and equipment as "Assets held for sale" on the Consolidated Balance Sheet. Assets in this category related to a group of service stations outside the United States.

Summarized income statement information relating to discontinued operations is as follows:

	Year ended December 31		
	2006	2005	2004
Revenues and other income	\$ –	\$ –	\$ 635
Income from discontinued operations before income tax expense	–	–	394
Income from discontinued operations, net of tax	–	–	294

Not all assets sold or to be disposed of are classified as discontinued operations, mainly because the cash flows from the assets were not, or will not be, eliminated from the ongoing operations of the company.

Subsequent to December 31, 2006, approximately \$300 of the company's refining assets in the Netherlands met the criteria for classifying the assets as held for sale. The company expects to record a gain upon close of sale, which is subject to

signing of the sales agreement and obtaining necessary regulatory approvals.

NOTE 12.
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 shown in the table below. For certain equity affiliates, Chevron pays its share of some income taxes directly. For such affiliates, the equity in earnings do not include these taxes, which are reported on the Consolidated Statement of Income as "Income tax expense."

	Investments and Advances At December 31		Equity in Earnings Year ended December 31		
	2006	2005	2006	2005	2004
Upstream					
Tengizchevroil	\$ 5,507	\$ 5,007	\$ 1,817	\$ 1,514	\$ 950
Hamaca	928	1,189	319	390	98
Petroboscan	712	–	31	–	–
Other	682	679	123	139	148
Total Upstream	7,829	6,875	2,290	2,043	1,196
Downstream					
GS Caltex Corporation	2,176	1,984	316	320	296
Caspian Pipeline Consortium	990	1,014	117	101	140
Star Petroleum Refining Company Ltd.	787	709	116	81	207
Caltex Australia Ltd.	559	435	186	214	173
Colonial Pipeline Company	555	565	34	13	–
Other	1,839	1,562	358	273	143
Total Downstream	6,906	6,269	1,127	1,002	959
Chemicals					
Chevron Phillips Chemical Company LLC	2,044	1,908	697	449	334
Other	22	20	5	3	2
Total Chemicals	2,066	1,928	702	452	336
All Other					
Dynegy Inc.	254	682	68	189	86
Other	586	740	68	45	5
Total equity method	\$ 17,641	\$ 16,494	\$ 4,255	\$ 3,731	\$ 2,582
Other at or below cost	911	563			
Total investments and advances	\$ 18,552	\$ 17,057			
Total United States	\$ 4,191	\$ 4,624	\$ 955	\$ 833	\$ 588
Total International	\$ 14,361	\$ 12,433	\$ 3,300	\$ 2,898	\$ 1,994

Descriptions of major affiliates are as follows:

Tengizchevroil Chevron has a 50 percent equity ownership interest in Tengizchevroil (TCO), a joint venture formed in 1993 to develop the Tengiz and Korolev crude oil fields in Kazakhstan over a 40-year period.

Hamaca Chevron has a 30 percent interest in the Hamaca heavy oil production and upgrading project located in Venezuela's Orinoco Belt.

NOTE 12. INVESTMENTS AND ADVANCES - Continued

Petroboscan Chevron has a 39 percent interest in Petroboscan, a joint stock company formed in 2006 to operate the Boscan Field in Venezuela. Chevron previously operated the field under an operating service agreement. At December 31, 2006, the company's carrying value of its investment in Petroboscan was approximately \$300 higher than the amount of underlying equity in Petroboscan's net assets.

GS Caltex Corporation Chevron owns 50 percent of GS Caltex, a joint venture with GS Holdings. The joint venture, originally formed in 1967 between the LG Group and Caltex, imports, refines and markets petroleum products and petrochemicals predominantly in South Korea.

Caspian Pipeline Consortium Chevron has a 15 percent interest in the Caspian Pipeline Consortium (CPC), which provides the critical export route for crude oil from both TCO and Karachaganak. At December 31, 2006, the company's carrying value of its investment in CPC was about \$50 higher than the amount of underlying equity in CPC's net assets.

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

Caltex Australia Ltd. Chevron has a 50 percent equity ownership interest in Caltex Australia Limited (CAL). The remaining 50 percent of CAL is publicly owned. At December 31, 2006, the fair value of Chevron's share of CAL common stock was approximately \$2,400. The aggregate carrying value of the company's investment in CAL was approximately \$60 lower than the amount of underlying equity in CAL net assets.

Colonial Pipeline Company Chevron owns an approximate 23 percent equity interest in the Colonial Pipeline Company. The Colonial Pipeline system runs from Texas to New Jersey and transports petroleum products in a 13-state market. At December 31, 2006, the company's carrying value of its investment in Colonial Pipeline was approximately \$590 higher than the amount of underlying equity in Colonial Pipeline's net assets.

Chevron Phillips Chemical Company LLC Chevron owns 50 percent of Chevron Phillips Chemical Company LLC (CPChem), with the other half owned by ConocoPhillips Corporation. At December 31, 2006, the company's carrying value of its investment in CPChem was approximately \$80 lower than the amount of underlying equity in CPChem's net assets.

Dynegy Inc. Chevron owns a 19 percent equity interest in the common stock of Dynegy, a provider of electricity to markets and customers throughout the United States.

Investment in Dynegy Common Stock At December 31, 2006, the carrying value of the company's investment in Dynegy common stock was approximately \$250. This amount was about \$180 below the company's proportionate interest in Dynegy's underlying net assets. This difference is primarily the result of 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. This difference has been assigned to the extent practicable to specific Dynegy assets and liabilities, based upon the company's analysis of the various factors contributing to the decline in value of the Dynegy shares. The company's equity share of Dynegy's reported earnings is adjusted quarterly when appropriate 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, 2006, was approximately \$700.

Investment in Dynegy Preferred Stock In May 2006, the company's investment in Dynegy Series C preferred stock was redeemed at its face value of \$400. Upon redemption of the preferred stock, the company recorded a before-tax gain of \$130 (\$87 after tax).

Dynegy Proposed Business Combination With LS Power Group Dynegy and LS Power Group, a privately held power plant investor, developer and manager, announced in September 2006 that the companies had executed a definitive agreement to combine Dynegy's assets and operations with LS Power Group's power generation portfolio and for Dynegy to acquire a 50 percent ownership interest in a development joint venture with LS Power. Upon close of the transaction, Chevron will receive the same number of shares of the new company's Class A common stock that it currently holds in Dynegy. Chevron's ownership interest in the combined company will be approximately 11 percent. The transaction is subject to specified conditions, including the affirmative vote of two-thirds of Dynegy's common shareholders and the receipt of regulatory approvals.

Other Information "Sales and other operating revenues" on the Consolidated Statement of Income includes \$9,582, \$8,824 and \$7,933 with affiliated companies for 2006, 2005 and 2004, respectively. "Purchased crude oil and products" includes \$4,222, \$3,219 and \$2,548 with affiliated companies for 2006, 2005 and 2004, respectively.

"Accounts and notes receivable" on the Consolidated Balance Sheet includes \$1,297 and \$1,729 due from affiliated companies at December 31, 2006 and 2005, respectively. "Accounts payable" includes \$262 and \$249 due to affiliated companies at December 31, 2006 and 2005, respectively.

NOTE 12. INVESTMENTS AND ADVANCES - Continued

The following table provides summarized financial information on a 100 percent basis for all equity affiliates as well as Chevron's total share, which includes Chevron loans to affiliates of \$3,915 at December 31, 2006.

Year ended December 31	Affiliates			Chevron Share		
	2006	2005	2004	2006	2005	2004
Total revenues	\$ 73,746	\$ 64,642	\$ 55,152	\$ 35,695	\$ 31,252	\$ 25,916
Income before income tax expense	10,973	7,883	5,309	5,295	4,165	3,015
Net income	7,905	6,645	4,441	4,072	3,534	2,582
At December 31						
Current assets	\$ 19,769	\$ 19,903	\$ 16,506	\$ 8,944	\$ 8,537	\$ 7,540
Noncurrent assets	49,896	46,925	38,104	18,575	17,747	15,567
Current liabilities	15,254	13,427	10,949	6,818	6,034	4,962
Noncurrent liabilities	24,059	26,579	22,261	3,902	4,906	4,520
Net equity	\$ 30,352	\$ 26,822	\$ 21,400	\$ 16,799	\$ 15,344	\$ 13,625

NOTE 13.

PROPERTIES, PLANT AND EQUIPMENT¹

	At December 31						Year ended December 31					
	Gross Investment at Cost			Net Investment			Additions at Cost ²			Depreciation Expense ^{3,4}		
	2006	2005	2004	2006	2005	2004	2006	2005	2004	2006	2005	2004
Upstream												
United States	\$ 46,191	\$ 43,390	\$ 37,329	\$ 16,706	\$ 15,327	\$ 10,047	\$ 3,739	\$ 2,160	\$ 1,584	\$ 2,374	\$ 1,869	\$ 1,508
International	61,281	54,497	38,721	37,730	34,311	21,192	7,290	4,897	3,090	3,888	2,804	2,180
Total Upstream	107,472	97,887	76,050	54,436	49,638	31,239	11,029	7,057	4,674	6,262	4,673	3,688
Downstream												
United States	14,553	13,832	12,826	6,741	6,169	5,611	1,109	793	482	474	461	490
International	11,036	11,235	10,843	5,233	5,529	5,443	532	453	441	551	550	572
Total Downstream	25,589	25,067	23,669	11,974	11,698	11,054	1,641	1,246	923	1,025	1,011	1,062
Chemicals												
United States	645	624	615	289	282	292	25	12	12	19	19	20
International	771	721	725	431	402	392	54	43	27	24	23	26
Total Chemicals	1,416	1,345	1,340	720	684	684	79	55	39	43	42	46
All Other⁵												
United States	3,243	3,127	2,877	1,709	1,655	1,466	270	199	314	171	186	158
International	27	20	18	19	15	15	8	4	2	5	1	3
Total All Other	3,270	3,147	2,895	1,728	1,670	1,481	278	203	316	176	187	161
Total United States	64,632	60,973	53,647	25,445	23,433	17,416	5,143	3,164	2,392	3,038	2,535	2,176
Total International	73,115	66,473	50,307	43,413	40,257	27,042	7,884	5,397	3,560	4,468	3,378	2,781
Total	\$ 137,747	\$ 127,446	\$ 103,954	\$ 68,858	\$ 63,690	\$ 44,458	\$ 13,027	\$ 8,561	\$ 5,952	\$ 7,506	\$ 5,913	\$ 4,957

¹ Includes assets acquired in connection with the acquisition of Unocal Corporation in August 2005. Refer to Note 2, beginning on page 58, for additional information.

² Net of dry hole expense related to prior years' expenditures of \$120, \$28 and \$58 in 2006, 2005 and 2004, respectively.

³ Depreciation expense includes accretion expense of \$275, \$187 and \$93 in 2006, 2005 and 2004, respectively.

⁴ Depreciation expense includes discontinued operations of \$22 in 2004.

⁵ Primarily mining operations, power generation businesses, real estate assets and management information systems.

NOTE 14.

ACCOUNTING FOR BUY/SELL CONTRACTS

The company adopted the accounting prescribed by EITF Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (Issue 04-13) on a prospective basis from April 1, 2006. Issue 04-13 requires that two or more legally separate exchange transactions with the same counterparty, including buy/sell transactions, be combined and considered as a single arrangement for purposes of applying the provisions of Accounting Principles Board Opinion No. 29, *Accounting for Nonmonetary Transactions*, when the transactions are entered into "in contemplation" of one

another. In prior periods, the company accounted for buy/sell transactions in the Consolidated Statement of Income as a monetary transaction – purchases were reported as "Purchased crude oil and products"; sales were reported as "Sales and other operating revenues."

With the company's adoption of Issue 04-13, buy/sell transactions beginning in the second quarter 2006 are netted against each other on the Consolidated Statement of Income, with no effect on net income. Amounts associated with buy/sell transactions in periods prior to the second quarter 2006 are shown as a footnote to the Consolidated Statement of Income on page 51.

NOTE 15.

LITIGATION

MTBE Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. Chevron is a party to approximately 75 lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners, related to the use of MTBE in certain oxygenated gasolines and the alleged seepage of MTBE into groundwater. Resolution of these actions may ultimately 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. The company currently does not use MTBE in the manufacture of gasoline in the United States.

RFG Patent Fourteen purported class actions were brought by consumers of reformulated gasoline (RFG) alleging that Unocal misled the California Air Resources Board into adopting standards for composition of RFG that overlapped with Unocal's undisclosed and pending patents. Eleven lawsuits are now consolidated in U.S. District Court for the Central District of California and three are consolidated in California State Court. Unocal is alleged to have monopolized, conspired and engaged in unfair methods of competition, resulting in injury to consumers of RFG. Plaintiffs in both consolidated actions seek unspecified actual and punitive damages, attorneys' fees, and interest on behalf of an alleged class of consumers who purchased "summertime" RFG in California from January 1995 through August 2005. Unocal believes it has valid defenses and intends to vigorously defend against these lawsuits. The company's potential exposure related to these lawsuits cannot currently be estimated.

NOTE 16.

TAXES

	Year ended December 31		
	2006	2005	2004
Taxes on income*			
U.S. federal			
Current	\$ 2,828	\$ 1,459	\$ 2,246
Deferred	200	567	(290)
State and local	581	409	345
Total United States	3,609	2,435	2,301
International			
Current	11,030	7,837	5,150
Deferred	199	826	66
Total International	11,229	8,663	5,216
Total taxes on income	\$ 14,838	\$ 11,098	\$ 7,517

*Excludes income tax expense of \$100 related to discontinued operations for 2004.

In 2006, the before-tax income for U.S. operations, including related corporate and other charges, was \$9,131, compared with a before-tax income of \$6,733 and \$7,776 in 2005 and 2004, respectively. For international operations, before-tax income was \$22,845, \$18,464 and \$12,775 in 2006, 2005 and 2004, respectively. U.S. federal income tax expense was reduced by \$116, \$289 and \$176 in 2006, 2005 and 2004, respectively, for business tax credits.

The reconciliation between the U.S. statutory federal income tax rate and the company's effective income tax rate is explained in the table below:

	Year ended December 31		
	2006	2005	2004
U.S. statutory federal income tax rate	35.0%	35.0%	35.0%
Effect of income taxes from international operations at rates different from the U.S. statutory rate	10.3	9.2	5.3
State and local taxes on income, net of U.S. federal income tax benefit	1.0	1.0	0.9
Prior-year tax adjustments	0.9	0.1	(1.0)
Tax credits	(0.4)	(1.1)	(0.9)
Effects of enacted changes in tax laws	0.3	—	(0.6)
Capital loss tax benefit	—	(0.1)	(2.1)
Other	(0.7)	—	—
Effective tax rate	46.4%	44.1%	36.6%

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	
	2006	2005
Deferred tax liabilities		
Properties, plant and equipment	\$ 16,054	\$ 14,220
Investments and other	2,137	1,469
Total deferred tax liabilities	18,191	15,689
Deferred tax assets		
Abandonment/environmental reserves	(2,925)	(2,083)
Employee benefits	(2,707)	(1,250)
Tax loss carryforwards	(1,509)	(1,113)
Capital losses	(246)	(246)
Deferred credits	(1,670)	(1,618)
Foreign tax credits	(1,916)	(1,145)
Inventory	(378)	(182)
Other accrued liabilities	(375)	(240)
Miscellaneous	(1,144)	(1,237)
Total deferred tax assets	(12,870)	(9,114)
Deferred tax assets valuation allowance	4,391	3,249
Total deferred taxes, net	\$ 9,712	\$ 9,824

In 2006, deferred tax liabilities increased by approximately \$2,500 from the amount reported in 2005. The

NOTE 16. TAXES - Continued

increase was primarily related to increased temporary differences for properties, plant and equipment.

Deferred tax assets increased by approximately \$3,800 in 2006. The increase related primarily to higher pension and other benefit obligations resulting from the implementation of FAS 158, increased foreign tax credits resulting from higher crude oil prices in tax jurisdictions with high income tax rates, and increased asset retirement obligations.

The overall valuation allowance relates to foreign tax credit carryforwards, tax loss carryforwards and temporary differences for which no benefit is expected to be realized. Tax loss carryforwards exist in many international jurisdictions. Whereas some of these tax loss carryforwards do not have an expiration date, others expire at various times from 2007 through 2029. Foreign tax credit carryforwards of \$1,916 will expire between 2009 and 2016.

At December 31, 2006 and 2005, deferred taxes were classified in the Consolidated Balance Sheet as follows:

	At December 31	
	2006	2005
Prepaid expenses and other current assets	\$ (1,167)	\$ (892)
Deferred charges and other assets	(844)	(547)
Federal and other taxes on income	76	1
Noncurrent deferred income taxes	11,647	11,262
Total deferred income taxes, net	\$ 9,712	\$ 9,824

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 \$21,035 at December 31, 2006. A significant majority of this amount represents earnings reinvested as part of the company's ongoing international business. It is not practicable to estimate the amount of taxes that might be payable on the eventual remittance of such earnings. The company does not anticipate incurring significant additional taxes on remittances of earnings that are not indefinitely reinvested.

American Jobs Creation Act of 2004 In October 2004, the American Jobs Creation Act of 2004 was passed into law. The Act provides a deduction for income from qualified domestic refining and upstream production activities, which is to be phased in from 2005 through 2010. The company expects the net effect of this provision of the Act to result in a decrease in the federal effective tax rate for 2007 to approximately 33 percent, based on current earnings levels. In the long term, the company expects that the new deduction will result in a decrease of the annual effective tax rate to about 32 percent for that category of income, based on current earnings levels.

Taxes other than on income were as follows:

	Year ended December 31		
	2006	2005	2004
United States			
Excise and other similar taxes on products and merchandise	\$ 4,831	\$ 4,521	\$ 4,147
Import duties and other levies	32	8	5
Property and other miscellaneous taxes	475	392	359
Payroll taxes	155	149	137
Taxes on production	360	323	257
Total United States	5,853	5,393	4,905
International			
Excise and other similar taxes on products and merchandise	4,720	4,198	3,821
Import duties and other levies	9,618	10,466	10,542
Property and other miscellaneous taxes	491	535	415
Payroll taxes	75	52	52
Taxes on production	126	138	86
Total International	15,030	15,389	14,916
Total taxes other than on income*	\$ 20,883	\$ 20,782	\$ 19,821

*Includes taxes on discontinued operations of \$3 in 2004.

NOTE 17.
SHORT-TERM DEBT

	At December 31	
	2006	2005
Commercial paper*	\$ 3,472	\$ 4,098
Notes payable to banks and others with originating terms of one year or less	122	170
Current maturities of long-term debt	2,176	467
Current maturities of long-term capital leases	57	70
Redeemable long-term obligations		
Long-term debt	487	487
Capital leases	295	297
Subtotal	6,609	5,589
Reclassified to long-term debt	(4,450)	(4,850)
Total short-term debt	\$ 2,159	\$ 739

*Weighted-average interest rates at December 31, 2006 and 2005, were 5.25 percent and 4.18 percent, respectively.

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 7, beginning on page 61, for information concerning the company's debt-related derivative activities.

At December 31, 2006, the company had \$4,950 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

NOTE 17. SHORT-TERM DEBT - Continued

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 2006 or at year-end.

At December 31, 2006 and 2005, the company classified \$4,450 and \$4,850, respectively, of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital in 2007, as the company has both the intent and the ability to refinance this debt on a long-term basis.

NOTE 18.

LONG-TERM DEBT

Chevron has three “shelf” registration statements on file with the SEC that together would permit the issuance of \$3,800 of debt securities pursuant to Rule 415 of the Securities Act of 1933. Total long-term debt, excluding capital leases, at December 31, 2006, was \$7,405. The company’s long-term debt outstanding at year-end 2006 and 2005 was as follows:

	At December 31	
	2006	2005
3.5% notes due 2007	\$ 1,996	\$ 1,992
3.375% notes due 2008	738	736
5.5% notes due 2009	401	406
9.75% debentures due 2020	250	250
7.327% amortizing notes due 2014 ¹	213	247
8.625% debentures due 2031	199	199
8.625% debentures due 2032	199	199
7.5% debentures due 2043	198	198
8.625% debentures due 2010	150	150
8.875% debentures due 2021	150	150
8% debentures due 2032	148	148
7.09% notes due 2007	144	144
7.5% debentures due 2029	—	475
5.05% debentures due 2012	—	412
7.35% debentures due 2009	—	347
7% debentures due 2028	—	259
Fixed and floating interest rate loans due 2007 to 2009	—	194
9.125% debentures due 2006	—	167
8.25% debentures due 2006	—	129
Medium-term notes, maturing from 2017 to 2043 (7.7%) ²	210	210
Fixed interest rate notes, maturing from 2007 to 2011 (7.4%) ²	46	241
Other foreign currency obligations (2.2%) ²	23	30
Other long-term debt (7.6%) ²	66	141
Total including debt due within one year	5,131	7,424
Debt due within one year	(2,176)	(467)
Reclassified from short-term debt	4,450	4,850
Total long-term debt	\$ 7,405	\$ 11,807

¹ Guarantee of ESOP debt.

² Less than \$100 individually; weighted-average interest rate at December 31, 2006.

Long-term debt of \$5,131 matures as follows: 2007 – \$2,176; 2008 – \$805; 2009 – \$428; 2010 – \$185; 2011 – \$50; and after 2011 – \$1,487.

In the first quarter of 2006, \$185 of Union Oil Company bonds were retired at maturity. In the second quarter, the company redeemed approximately \$1,700 of Unocal debt and recognized a \$92 before-tax gain. In October 2006, a \$129 Texaco Capital Inc. bond matured. In November 2006, the company retired Union Oil Company bonds of \$196.

NOTE 19.

NEW ACCOUNTING STANDARDS

EITF Issue No. 04-6, Accounting for Stripping Costs Incurred During Production in the Mining Industry (Issue 04-6)

In March 2005, the FASB ratified the earlier Emerging Issues Task Force (EITF) consensus on Issue 04-6, which was adopted by the company on January 1, 2006. Stripping costs are costs of removing overburden and other waste materials to access mineral deposits. The consensus calls for stripping costs incurred once a mine goes into production to be treated as variable production costs that should be considered a component of mineral inventory cost subject to ARB No. 43, *Restatement and Revision of Accounting Research Bulletins*. Adoption of this accounting for the company’s coal, oil sands and other mining operations resulted in a \$19 reduction of retained earnings as of January 1, 2006.

FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes – An Interpretation of FASB Statement No. 109 (FIN 48)

In July 2006, the FASB issued FIN 48, which became effective for the company on January 1, 2007. This interpretation clarifies the accounting for income tax benefits that are uncertain in nature. Under FIN 48, a company will recognize a tax benefit in the financial statements for an uncertain tax position only if management’s assessment is that its position is “more likely than not” (i.e., a greater than 50 percent likelihood) to be upheld on audit based only on the technical merits of the tax position. This accounting interpretation also provides guidance on measurement methodology, derecognition thresholds, financial statement classification and disclosures, interest and penalties recognition, and accounting for the cumulative-effect adjustment. The new interpretation is intended to provide better financial statement comparability among companies.

Required annual disclosures include a tabular reconciliation of unrecognized tax benefits at the beginning and end of the period; the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate; the amounts of interest and penalties recognized in the financial statements; any expected significant impacts from unrecognized tax benefits on the financial statements over the subsequent 12-month reporting period; and a description of the tax years remaining to be examined in major tax jurisdictions.

As a result of the implementation of FIN 48, the company expects to recognize an increase in the liability for unrecognized

nized tax benefits and associated interest and penalties as of January 1, 2007. In connection with this increase in liability, the company estimates retained earnings at the beginning of 2007 will be reduced by \$250 or less. The amount of the liability and impact on retained earnings will depend in part on clarification expected to be issued by the FASB related to the criteria for determining the date of ultimate settlement with a tax authority.

FASB Statement No. 157, Fair Value Measurements (FAS 157) In September 2006, the FASB issued FAS 157, which will become effective for the company on January 1, 2008. This standard defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The Statement does not require any new fair value measurements but would apply to assets and liabilities that are required to be recorded at fair value under other accounting standards. The impact, if any, to the company from the adoption of FAS 157 in 2008 will depend on the company's assets and liabilities at that time that are required to be measured at fair value.

FASB Statement No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an Amendment of FASB Statements No. 87, 88, 106 and 132(R) (FAS 158) In September 2006, the FASB issued FAS 158, which was adopted by the company on December 31, 2006. Refer to Note 21, beginning on page 72 for additional information.

NOTE 20.

ACCOUNTING FOR SUSPENDED EXPLORATORY WELLS

The company accounts for the cost of exploratory wells in accordance with FASB Statement No. 19, *Financial and Reporting by Oil and Gas Producing Companies* (FAS 19), as amended by FASB Staff Position (FSP) FAS 19-1, *Accounting for Suspended Well Costs*, which provides that exploratory well costs continue to be capitalized after the completion of drilling when (a) the well has found a sufficient quantity of reserves to justify completion as a producing well and (b) the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met or if an enterprise obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well would be assumed to be impaired, and its costs, net of any salvage value, would be charged to expense. FAS 19 provides a number of indicators that can assist an entity to demonstrate sufficient progress is being made in assessing the reserves and economic viability of the project.

The following table indicates the changes to the company's suspended exploratory well costs for the three years ended December 31, 2006. No capitalized exploratory well costs were charged to expense upon the 2005 adoption of FSP FAS 19-1.

	Year ended December 31		
	2006	2005	2004
Beginning balance at January 1	\$ 1,109	\$ 671	\$ 549
Additions associated with the acquisition of Unocal	–	317	–
Additions to capitalized exploratory well costs pending the determination of proved reserves	446	290	252
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(171)	(140)	(64)
Capitalized exploratory well costs charged to expense	(121)	(6)	(66)
Other reductions*	(24)	(23)	–
Ending balance at December 31	\$ 1,239	\$ 1,109	\$ 671

*Represent property sales and exchanges.

The following table provides an aging of capitalized well costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling. The aging of the former Unocal wells is based on the date the drilling was completed, rather than Chevron's acquisition of Unocal in 2005.

	Year ended December 31		
	2006	2005	2004
Exploratory well costs capitalized for a period of one year or less	\$ 332	\$ 259	\$ 222
Exploratory well costs capitalized for a period greater than one year	907	850	449
Balance at December 31	\$ 1,239	\$ 1,109	\$ 671
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	44	40	22

*Certain projects have multiple wells or fields or both.

Of the \$907 of exploratory well costs capitalized for a period greater than one year at December 31, 2006, \$447 (23 projects) is related to projects that had drilling activities under way or firmly planned for the near future. An additional \$63 (one project) had drilling activity during 2006. The \$397 balance related to 20 projects in areas requiring a major capital expenditure before production could begin and for which additional drilling efforts were not under way or firmly planned for the near future. Additional drilling was not deemed necessary because the presence of hydrocarbons had already been established, and other activities were in process to enable a future decision on project development.

The projects for the \$397 referenced above had the following activities associated with assessing the reserves and the projects' economic viability: (a) \$99 (two projects) – development plans submitted to a government in early 2007; (b) \$80 (one project) – pre-FEED (front-end engineering and design) studies are ongoing with FEED expected to commence in 2007; (c) \$75 (three projects) – continued to pursue unitization opportunities on adjacent discoveries that

**NOTE 20. ACCOUNTING FOR SUSPENDED
EXPLORATORY WELLS - Continued**

span international boundaries; (d) \$42 (one project) – finalize analysis of new seismic study to determine the development facility concept; (e) \$101 – miscellaneous activities for 13 projects with smaller amounts suspended. While progress was being made on all the projects in this category, the decision on the recognition of proved reserves under SEC rules in some cases may not occur for several years because of the complexity, scale and negotiations connected with the projects. The majority of these decisions are expected to occur in the next three years.

The \$907 of suspended well costs capitalized for a period greater than one year as of December 31, 2006, represents 110 exploratory wells in 44 projects. The tables below contain the aging of these costs on a well and project basis:

<i>Aging based on drilling completion date of individual wells:</i>	Amount	Number of wells
1994–1996	\$ 27	3
1997–2001	128	33
2002–2005	752	74
Total	\$ 907	110

<i>Aging based on drilling completion date of last well in project:</i>	Amount	Number of projects
1999–2001	\$ 9	2
2002–2006	898	42
Total	\$ 907	44

NOTE 21.

EMPLOYEE BENEFIT PLANS

The company has defined-benefit pension plans for many employees. The company typically prefunds defined-benefit plans as required by local regulations or in certain situations where prefunding provides economic advantages. In the United States, all qualified plans are subject to the Employee Retirement Income Security Act (ERISA) minimum funding standard. The company does not typically fund U.S. nonqualified pension plans that are not subject to funding requirements under laws and regulations because contributions to these pension plans may be less economic and investment returns may be less attractive than the company's other investment alternatives.

The company also sponsors other postretirement plans that provide medical and dental benefits, as well as life insurance for some active and qualifying retired employees. The plans are unfunded, and the company and the retirees share the costs. Medical coverage for Medicare-eligible retirees in the company's main U.S. medical plan is secondary to Medicare (including Part D) and the increase to the company contribution for retiree medical coverage is limited to no more than 4 percent per year. This contribution cap becomes effective in the year of retirement for pre-Medicare-eligible employees retiring on or after January 1, 2005. The cap was effective as of January 1, 2005, for pre-Medicare-eligible retirees retiring

before that date and all Medicare-eligible retirees. Certain life insurance benefits are paid by the company, and annual contributions are based on actual plan experience.

In June 2006, the company announced changes to several of its U.S. pension and other postretirement benefit plans, primarily merging benefits under several Unocal plans into related Chevron plans. Under the plan combinations, former-Unocal employees retiring on or after July 1, 2006, received recognition for Unocal pay and service history toward benefits to be paid under the Chevron pension and postretirement benefit plans. Unocal employees who retired before July 1, 2006, and were participating in the Unocal postretirement medical plan were merged into the Chevron primary U.S. plan effective January 1, 2007. In addition, the company's contributions for Medicare-eligible retirees under the Chevron plan were increased in 2007 in conjunction with the merger of former-Unocal participants into the Chevron plan.

Effective December 31, 2006, the company implemented the recognition and measurement provisions of Financial Accounting Standards Board (FASB) Statement No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)* (FAS 158), which requires the recognition of the overfunded or underfunded status of each of its defined benefit pension and other postretirement benefit plans as an asset or liability, with the offset to "Accumulated other comprehensive loss." In addition, Chevron recognized its share of amounts recorded by affiliated companies in "Accumulated other comprehensive loss" to reflect their adoption of FAS 158 at December 31, 2006. The following table illustrates the incremental effect of the adoption of FAS 158 on individual lines in the company's December 2006 "Consolidated Balance Sheet" after applying the additional minimum liability adjustment required by FASB Statement No. 87, *Employers' Accounting for Pensions*.

	Before Application of FAS 158*	FAS 158 Adjustments	After Application of FAS 158
Noncurrent assets –			
Investments and advances	\$ 18,542	\$ 10	\$ 18,552
Noncurrent assets –			
Deferred charges and other assets	\$ 4,794	\$ (2,706)	\$ 2,088
Total assets	\$ 135,324	\$ (2,696)	\$ 132,628
Noncurrent liabilities – Noncurrent			
deferred income taxes	\$ 12,924	\$ (1,277)	\$ 11,647
Noncurrent liabilities – Reserves for			
employee benefits	\$ 3,965	\$ 784	\$ 4,749
Total liabilities	\$ 64,186	\$ (493)	\$ 63,693
Accumulated other			
comprehensive (loss)	\$ (433)	\$ (2,203)	\$ (2,636)
Total stockholders' equity	\$ 71,138	\$ (2,203)	\$ 68,935

*Accounts include minimum pension liabilities of \$636 (\$40 for affiliates) recognized prior to application of FAS 158 at December 31, 2006. Deferred income taxes of \$234 (\$13 for affiliates) were recognized on the amounts reflected in "Accumulated other comprehensive loss."

NOTE 21. EMPLOYEE BENEFIT PLANS - Continued

The company uses a measurement date of December 31 to value its benefit plan assets and obligations. The funded status of the company's pension and other postretirement benefit plans for 2006 and 2005 is as follows:

	Pension Benefits				Other Benefits	
	2006		2005		2006	2005
	U.S.	Int'l.	U.S.	Int'l.		
CHANGE IN BENEFIT OBLIGATION						
Benefit obligation at January 1	\$ 8,594	\$ 3,611	\$ 6,587	\$ 3,144	\$ 3,252	\$ 2,820
Assumption of Unocal benefit obligations	—	—	1,437	169	—	277
Service cost	234	98	208	84	35	30
Interest cost	468	214	395	199	181	164
Plan participants' contributions	—	7	1	6	134	129
Plan amendments	14	37	42	7	107	—
Actuarial loss	297	97	593	476	(102)	189
Foreign currency exchange rate changes	—	355	—	(293)	(5)	(2)
Benefits paid	(815)	(212)	(669)	(181)	(345)	(355)
Benefit obligation at December 31	8,792	4,207	8,594	3,611	3,257	3,252
CHANGE IN PLAN ASSETS						
Fair value of plan assets at January 1	7,463	2,890	5,776	2,634	—	—
Acquisition of Unocal plan assets	—	—	1,034	65	—	—
Actual return on plan assets	1,069	225	527	441	—	—
Foreign currency exchange rate changes	—	321	—	(303)	—	—
Employer contributions	224	225	794	228	211	226
Plan participants' contributions	—	7	1	6	134	129
Benefits paid	(815)	(212)	(669)	(181)	(345)	(355)
Fair value of plan assets at December 31	7,941	3,456	7,463	2,890	—	—
FUNDED STATUS AT DECEMBER 31	(851)	(751)	(1,131)	(721)	(3,257)	(3,252)
Unrecognized net actuarial loss	—	—	2,332	1,108	—	1,167
Unrecognized prior-service cost	—	—	305	89	—	(679)
Unrecognized net transitional assets	—	—	—	5	—	—
Total recognized at December 31	\$ (851)	\$ (751)	\$ 1,506	\$ 481	\$ (3,257)	\$ (2,764)

Amounts recognized in the Consolidated Balance Sheet for the company's pension and other postretirement benefit plans at December 31, 2005, reflected the net of cumulative employer contributions and net periodic benefit costs recognized in earnings. The 2005 amounts for noncurrent pension liabilities also included minimum pension liability adjustments, which were offset in "Accumulated other comprehensive loss" and "Deferred charges and other assets." Amounts recognized at December 31, 2006, reflected the net funded status of each of the company's defined-benefit pension and other postretirement plans presented as either a net asset (overfunded) or a liability (underfunded).

	Pension Benefits				Other Benefits	
	2006		2005		2006	2005
	U.S.	Int'l.	U.S.	Int'l.		
Noncurrent assets – Prepaid benefit cost ¹	\$ 18	\$ 96	\$ 1,961	\$ 960	\$ —	\$ —
Noncurrent assets – Intangible asset ¹	—	—	12	2	—	—
Current liabilities – Accrued liabilities	(53)	(47)	(57)	(17)	(223)	(186)
Noncurrent liabilities – Reserves for employee benefit plans ²	(816)	(800)	(833)	(528)	(3,034)	(2,578)
Accumulated other comprehensive income ³ –						
Minimum pension liability	—	—	423	64	—	—
Net amount recognized	\$ (851)	\$ (751)	\$ 1,506	\$ 481	\$ (3,257)	\$ (2,764)

¹ Noncurrent assets are recorded in "Deferred charges and other assets" on the Consolidated Balance Sheet.

² The company recorded additional minimum liabilities of \$435 and \$66 in 2005 for U.S. and international pension plans, respectively.

³ "Accumulated other comprehensive loss" in 2005 includes deferred income taxes of \$148 and \$22 for U.S. and international plans, respectively. This amount is presented net of those taxes in the Consolidated Statement of Stockholders' Equity.

NOTE 21. EMPLOYEE BENEFIT PLANS - Continued

Amounts recognized on a before-tax basis in “Accumulated other comprehensive loss” for the company’s pension and other postretirement plans (excludes affiliates) at the end of 2006 after adoption of FAS 158 consisted of:

	Pension Benefits		Other Benefits
	2006		
	U.S.	Int'l.	2006
Net actuarial loss	\$ 1,892	\$ 1,288	\$ 972
Prior-service cost (credit)	272	126	(485)
Total recognized at December 31	\$ 2,164	\$ 1,414	\$ 487

The accumulated benefit obligations for all U.S. and international pension plans were \$7,987 and \$3,669 respectively, at December 31, 2006, and \$7,931 and \$3,080, respectively, at December 31, 2005.

The components of net periodic benefit cost for 2006, 2005 and 2004 were:

	Pension Benefits						Other Benefits		
	2006		2005		2004		2006	2005	2004
	U.S.	Int’l.	U.S.	Int’l.	U.S.	Int’l.			
Service cost	\$ 234	\$ 98	\$ 208	\$ 84	\$ 170	\$ 70	\$ 35	\$ 30	\$ 26
Interest cost	468	214	395	199	326	180	181	164	164
Expected return on plan assets	(550)	(227)	(449)	(208)	(358)	(169)	—	—	—
Amortization of transitional assets	—	1	—	2	—	1	—	—	—
Amortization of prior-service costs	46	14	45	16	42	16	(86)	(91)	(47)
Recognized actuarial losses	149	69	177	51	114	69	97	93	54
Settlement losses	70	—	86	—	96	4	—	—	—
Curtailment losses	—	—	—	—	—	2	—	—	—
Special termination benefits recognition	—	—	—	—	—	1	—	—	—
Net periodic benefit cost	\$ 417	\$ 169	\$ 462	\$ 144	\$ 390	\$ 174	\$ 227	\$ 196	\$ 197

Net actuarial losses recorded in “Accumulated other comprehensive income” at December 31, 2006, related to the company’s U.S. pension, international pension and other postretirement benefit plans are being amortized on a straight-line basis over approximately nine, 13 and 10 years, respectively. These amortization periods represent the estimated average remaining service of employees expected to receive benefits under the plans. These losses are amortized to the extent they exceed 10 percent of the higher of the projected benefit obligation or market-related value of plan assets. The amount subject to amortization is determined on a plan-by-plan basis. During 2007, the company estimates actuarial losses of \$139 and \$81 will be amortized

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2006 and 2005, was:

	Pension Benefits			
	2006		2005	
	U.S.	Int’l.	U.S.	Int’l.
Projected benefit obligations	\$ 848	\$ 849	\$ 2,132	\$ 818
Accumulated benefit obligations	806	741	1,993	632
Fair value of plan assets	12	172	1,206	153

from accumulated other comprehensive income for U.S. and international pension plans, and actuarial losses of \$81 will be amortized from accumulated other comprehensive income for other postretirement benefit plans.

The weighted average amortization period for recognizing prior service costs (credits) recorded at December 31, 2006, was approximately six and 13 years for U.S. and international pension plans, respectively, and seven years for other postretirement benefit plans. During 2007, the company estimates prior service costs of \$46 and \$17 will be amortized from accumulated other comprehensive income for U.S. and international pension plans, and prior service credits of \$81 will be amortized from accumulated other comprehensive income for other postretirement benefit plans.

NOTE 21. EMPLOYEE BENEFIT PLANS - Continued

Assumptions The following weighted-average assumptions were used to determine benefit obligations and net periodic benefit costs for years ended December 31:

	Pension Benefits						Other Benefits		
	2006		2005		2004		2006	2005	2004
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.			
Assumptions used to determine benefit obligations									
Discount rate	5.8%	6.0%	5.5%	5.9%	5.8%	6.4%	5.8%	5.6%	5.8%
Rate of compensation increase	4.5%	6.1%	4.0%	5.1%	4.0%	4.9%	4.5%	4.0%	4.1%
Assumptions used to determine net periodic benefit cost									
Discount rate ^{1,2,3}	5.8%	5.9%	5.5%	6.4%	5.9%	6.8%	5.9%	5.8%	6.1%
Expected return on plan assets ^{1,2}	7.8%	7.4%	7.8%	7.9%	7.8%	8.3%	N/A	N/A	N/A
Rate of compensation increase ²	4.2%	5.1%	4.0%	5.0%	4.0%	4.9%	4.2%	4.0%	4.1%

¹ Discount rate and expected rate of return on plan assets were reviewed and updated as needed on a quarterly basis for the main U.S. pension plan.

² The 2005 discount rate, expected return on plan assets and rate of compensation increase reflect the remeasurement of the Unocal benefit plans at July 31, 2005, due to the acquisition of Unocal.

³ The 2006 U.S. discount rate reflects remeasurement on July 1, 2006, due to plan combinations and changes, primarily merging benefits under several Unocal plans into related Chevron plans.

Expected Return on Plan Assets The company's estimates of the long-term rate of return on pension assets is driven primarily by actual historical asset-class returns, an assessment of expected future performance, advice from external actuarial firms and the incorporation of specific asset-class risk factors. Asset allocations are periodically 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.

There have been no changes in the expected long-term rate of return on plan assets since 2002 for U.S. plans, which account for 70 percent of the company's pension plan assets. At December 31, 2006, the estimated long-term rate of return on U.S. pension plan assets was 7.8 percent.

The market-related value of assets of the major U.S. pension plan used in the determination of pension expense was based on the market values in the three months preceding the year-end measurement date, 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. For other plans, market value of assets as of the measurement date is used in calculating the pension expense.

Discount Rate The discount rate assumptions used to determine U.S. and international pension and postretirement benefit plan obligations and expense reflect the prevailing rates available on high-quality, fixed-income debt instruments. At December 31, 2006, the company selected a 5.8 percent discount rate based on Moody's Aa Corporate Bond Index and a cash flow analysis that matched estimated future benefit payments to the Citigroup Pension Discount Yield Curve. The discount rates at the end of 2005 and 2004 were 5.5 percent and 5.8 percent, respectively.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2006, for the main U.S. postretirement medical plan, the assumed health care cost-trend rates start with 9 percent in 2007 and gradually decline to 5 percent for 2011 and beyond. For this measurement at December 31, 2005, the assumed health care cost-trend rates started with 10 percent in 2006 and gradually decline to 5 percent for 2011 and beyond. In both measurements, the annual increase to company contributions was capped at 4 percent.

Assumed health care cost-trend rates can have a significant effect on the amounts reported for retiree health care costs. The impact is mitigated by the 4 percent cap on the company's medical contributions for the primary U.S. plan. 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	\$ 8	\$ (8)
Effect on postretirement benefit obligation	\$ 89	\$ (85)

Plan Assets and Investment Strategy The company's pension plan weighted-average asset allocations at December 31 by asset category are as follows:

Asset Category	U.S.		International	
	2006	2005	2006	2005
Equities	68%	69%	62%	60%
Fixed Income	21%	21%	37%	39%
Real Estate	10%	9%	1%	1%
Other	1%	1%	—	—
Total	100%	100%	100%	100%

The pension plans invest primarily in asset categories with sufficient size, liquidity and cost efficiency to permit investments of reasonable size. The pension plans invest in asset categories that provide diversification benefits and are easily

NOTE 21. EMPLOYEE BENEFIT PLANS - Continued

measured. To assess the plans' investment performance, long-term asset allocation policy benchmarks have been established.

For the primary U.S. pension plan, the Chevron Board of Directors has established the following approved asset allocation ranges: Equities 40–70 percent, Fixed Income 20–60 percent, Real Estate 0–15 percent and Other 0–5 percent. The significant international pension plans also have established maximum and minimum asset allocation ranges that vary by each plan. Actual asset allocation within approved ranges is based on a variety of current economic and market conditions and consideration of specific asset category risk.

Equities include investments in the company's common stock in the amount of \$17 and \$13 at December 31, 2006 and 2005, respectively. The "Other" asset category includes minimal investments in private-equity limited partnerships.

Cash Contributions and Benefit Payments In 2006, the company contributed \$224 and \$225 to its U.S. and international pension plans, respectively. In 2007, the company expects contributions to be approximately \$300 and \$200 to its U.S. and international pension plans, respectively. Actual contribution amounts are dependent upon plan-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.

The company anticipates paying other postretirement benefits of approximately \$223 in 2007, as compared with \$211 paid in 2006.

The following benefit payments, which include estimated future service, are expected to be paid in the next 10 years:

	Pension Benefits		Other Benefits
	U.S.	Int'l.	
2007	\$ 775	\$ 206	\$ 223
2008	\$ 755	\$ 228	\$ 226
2009	\$ 786	\$ 237	\$ 228
2010	\$ 821	\$ 253	\$ 233
2011	\$ 865	\$ 249	\$ 239
2012–2016	\$ 4,522	\$ 1,475	\$ 1,252

Employee Savings Investment Plan Eligible employees of Chevron and certain of its subsidiaries participate in the Chevron Employee Savings Investment Plan (ESIP).

Charges to expense for the ESIP represent the company's contributions to the plan, which are funded either through the purchase of shares of common stock on the open market or through the release of common stock held in the leveraged employee stock ownership plan (LESOP), which is discussed below. Total company matching contributions to employee accounts within the ESIP were \$169, \$145 and \$139 in 2006, 2005 and 2004, respectively. This cost was reduced by the value of shares released from the LESOP totaling \$6, \$4 and \$138 in 2006, 2005 and 2004, respectively. The remaining amounts,

totaling \$163, \$141 and \$1 in 2006, 2005 and 2004, respectively, represent open market purchases.

Employee Stock Ownership Plan Within the Chevron ESIP is an employee stock ownership plan (ESOP). In 1989, Chevron established a LESOP as a constituent part of the ESOP. The LESOP provides partial prefunding of the company's future commitments to the 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 AICPA Statement of Position 76-3, *Accounting Practices for Certain Employee Stock Ownership Plans*, and subsequent consensus of the EITF of the FASB. The debt of the LESOP is recorded as debt, and shares pledged as collateral are reported as "Deferred compensation and benefit plan trust" on 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 and used by the LESOP for debt service. Interest accrued on 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.

Total (credits) expenses recorded for the LESOP were \$(1), \$94 and \$(29) in 2006, 2005 and 2004, respectively, including \$17, \$18 and \$23 of interest expense related to LESOP debt and a (credit) charge to compensation expense of \$(18), \$76 and \$(52).

Of the dividends paid on the LESOP shares, \$59, \$55 and \$52 were used in 2006, 2005 and 2004, respectively, to service LESOP debt. The amount in 2006 included \$28 of LESOP debt service that was scheduled for payment on the first business day of January 2007 and was paid in late December 2006. Included in the 2004 amount was a repayment of debt entered into in 1999 to pay interest on the ESOP debt. Interest expense on this debt was recognized and reported as LESOP interest expense in 1999. In addition, the company made contributions in 2005 of \$98 to satisfy LESOP debt service in excess of dividends received by the LESOP. No contributions were required in 2006 or 2004 as dividends received by the LESOP were sufficient to satisfy LESOP debt service.

Shares held in the LESOP are released and allocated to the accounts of plan participants based on debt service deemed to be paid in the year in proportion to the total of current year and remaining debt service. LESOP shares as of December 31, 2006 and 2005, were as follows:

NOTE 21. EMPLOYEE BENEFIT PLANS - Continued

Thousands	2006	2005
Allocated shares	21,827	23,928
Unallocated shares	8,316	9,163
Total LESOP shares	30,143	33,091

Benefit Plan Trusts Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2006, the trust contained 14.2 million shares of Chevron 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.

Unocal established various grantor trusts to fund obligations under some of its benefit plans, including the deferred compensation and supplemental retirement plans. At December 31, 2006 and 2005, trust assets of \$98 and \$130, respectively, were invested primarily in interest-earning accounts.

Management Incentive Plans Chevron 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 MIP is an annual cash incentive plan that links awards to performance results of the prior year. The cash awards may be deferred by the recipients by conversion to stock units or other investment fund alternatives. Aggregate charges to expense for MIP were \$180, \$155 and \$147 in 2006, 2005 and 2004, respectively. Awards under the LTIP consist of stock options and other share-based compensation that are described in Note 22 below.

Other Incentive Plans The company has a program that provides eligible employees, other than those covered by MIP and LTIP, with an annual cash bonus if the company achieves certain financial and safety goals. Charges for the programs were \$329, \$324 and \$339 in 2006, 2005 and 2004, respectively.

NOTE 22.**STOCK OPTIONS AND OTHER SHARE-BASED COMPENSATION**

Effective July 1, 2005, the company adopted the provisions of Financial Accounting Standards Board (FASB) Statement No. 123R, *Share-Based Payment* (FAS 123R), for its share-based compensation plans. The company previously accounted for these plans under the recognition and measurement principles of Accounting Principles Board Opinion No. 25, *Accounting for*

Stock Issued to Employees, and related interpretations and disclosure requirements established by FASB Statement No. 123, *Accounting for Stock-Based Compensation* (FAS 123).

The company adopted FAS 123R using the modified prospective method and, accordingly, results for prior periods were not restated. Refer to Note 1, beginning on page 56, for the pro forma effect on net income and earnings per share as if the company had applied the fair-value recognition provisions of FAS 123 for periods prior to adoption of FAS 123R.

For 2006 and 2005, compensation expense charged against income for stock options was \$125 (\$81 after tax) and \$65 (\$42 after tax), respectively. In addition, compensation expense charged against income for stock appreciation rights, performance units and restricted stock units was \$113 (\$73 after tax), \$59 (\$39 after tax) and \$65 (\$42 after tax) for 2006, 2005 and 2004, respectively. There were no significant stock-based compensation costs at December 31, 2006 and 2005, that were capitalized.

Cash received from option exercises under all share-based payment arrangements for 2006, 2005 and 2004 was \$444, \$297 and \$385, respectively. Actual tax benefits realized for the tax deductions from option exercises were \$91, \$71 and \$49 for 2006, 2005 and 2004, respectively.

Cash paid to settle performance units and stock appreciation rights was \$68, \$110 and \$23 for 2006, 2005 and 2004, respectively. Cash paid in 2005 included \$73 for Unocal awards paid under change-in-control plan provisions.

The company presents the tax benefits of deductions from the exercise of stock options as financing cash inflows in the Consolidated Statement of Cash Flows. In the second quarter 2006, the company implemented the transition method of FASB Staff Position FAS 123R-3, *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards*, for calculating the beginning balance of the pool of excess tax benefits related to employee compensation and determining the subsequent impact on the pool of employee awards that were fully vested and outstanding upon the adoption of FAS 123R. The company's reported tax expense for the period subsequent to the implementation of FAS 123R was not affected by this election. Refer to Note 3, beginning on page 59, for information on excess tax benefits reported on the company's Statement of Cash Flows.

In the discussion below, the references to share price and number of shares have been adjusted for the two-for-one stock split in September 2004.

Chevron Long-Term Incentive Plan (LTIP) Awards under the LTIP may take the form of, but are not limited to, stock options, restricted stock, restricted stock units, stock appreciation rights, performance units and non-stock grants. From April 2004 through January 2014, no more than 160 million shares may be issued under the LTIP, and no more than

**NOTE 22. STOCK OPTIONS AND OTHER SHARE-BASED
COMPENSATION - Continued**

64 million of those shares may be in a form other than a stock option, stock appreciation right or award requiring full payment for shares by the award recipient.

Stock options and stock appreciation rights granted under the LTIP extend for 10 years from grant date. Effective with options granted in June 2002, one-third of each award vests on 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. Performance units granted under the LTIP settle in cash at the end of a three-year performance period. Settlement amounts are based on achievement of performance targets relative to major competitors over the period, and payments are indexed to the company's stock price.

Texaco Stock Incentive Plan (Texaco SIP) On the closing of the acquisition of Texaco in October 2001, outstanding options granted under the Texaco SIP were converted to Chevron options. These options retained a provision for being restored, which enables a participant who exercises a stock option to receive new options equal to the number of shares exchanged 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 market value of the common stock on the day the restored option is granted. Apart from the restored options, no further awards may be granted under the former Texaco plans.

Unocal Share-Based Plans (Unocal Plans) On the closing of the acquisition of Unocal in August 2005, outstanding stock options and stock appreciation rights granted under various Unocal Plans were exchanged for fully vested Chevron options and appreciation rights at a conversion ratio of 1.07 Chevron shares for each Unocal share. These awards retained the same provisions as the original Unocal Plans. Awards issued prior to 2004 generally may be exercised for up to three years after termination of employment (depending upon the terms of the individual award agreements) or the original expiration date, whichever is earlier. Awards issued since 2004 generally remain exercisable until the end of the normal option term if termination of employment occurs prior to August 10, 2007. Other awards issued under the Unocal Plans, including restricted stock, stock units, restricted stock units and performance shares, became vested at the acquisition date, and shares or cash were issued to recipients in accordance with change-in-control provisions of the plans.

The fair market values of stock options and stock appreciation rights granted in 2006, 2005 and 2004 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2006	2005	2004
Chevron LTIP			
Expected term in years ¹	6.4	6.4	7.0
Volatility ²	23.7%	24.5%	16.5%
Risk-free interest rate based on zero coupon U.S. treasury note	4.7%	3.8%	4.4%
Dividend yield	3.1%	3.4%	3.7%
Weighted-average fair value per option granted	\$ 12.74	\$ 11.66	\$ 7.14
Texaco SIP			
Expected term in years ¹	2.2	2.1	2.0
Volatility ²	19.6%	18.6%	17.8%
Risk-free interest rate based on zero coupon U.S. treasury note	4.8%	3.8%	2.5%
Dividend yield	3.3%	3.4%	3.8%
Weighted-average fair value per option granted	\$ 7.72	\$ 6.09	\$ 4.00
Unocal Plans³			
Expected term in years ¹	—	4.2	—
Volatility ²	—	21.6%	—
Risk-free interest rate based on zero coupon U.S. treasury note	—	3.9%	—
Dividend yield	—	3.4%	—
Weighted-average fair value per option granted	—	\$ 21.48	—

¹ Expected term is based on historical exercise and post-vesting cancellation data.

² Volatility rate is based on historical stock prices over an appropriate period, generally equal to the expected term.

³ Represents options converted at the acquisition date.

A summary of option activity during 2006 is presented below:

	Shares (Thousands)	Weighted- Average Exercise Price	Weighted- Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at				
January 1, 2006	59,524	\$ 45.32		
Granted	9,248	\$ 56.64		
Exercised	(14,921)	\$ 46.11		
Restored	4,002	\$ 64.13		
Forfeited	(1,908)	\$ 57.09		
Outstanding at				
December 31, 2006	55,945	\$ 47.91	6.0 yrs.	\$ 1,433
Exercisable at				
December 31, 2006	37,063	\$ 43.56	5.1 yrs.	\$ 1,111

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2006, 2005 and 2004 was \$281, \$258 and \$129, respectively.

At adoption of FAS 123R, the company elected to amortize newly issued graded awards on a straight-line basis over the requisite service period. In accordance with FAS 123R implementation guidance issued by the staff of the Securities and Exchange Commission, the company accelerates the vest-

**NOTE 22. STOCK OPTIONS AND OTHER SHARE-BASED
COMPENSATION - Continued**

ing period for retirement-eligible employees in accordance with vesting provisions of the company's share-based compensation programs for awards issued after adoption of FAS 123R. As of December 31, 2006, there was \$99 of total unrecognized before-tax compensation cost related to nonvested share-based compensation arrangements granted or restored under the plans. That cost is expected to be recognized over a weighted-average period of 2.0 years.

At January 1, 2006, the number of LTIP performance units outstanding was equivalent to 2,346,016 shares. During 2006, 709,200 units were granted, 827,450 units vested with cash proceeds distributed to recipients, and 117,570 units were forfeited. At December 31, 2006, units outstanding were 2,110,196, and the fair value of the liability recorded for these instruments was \$113. In addition, outstanding stock appreciation rights that were awarded under various LTIP and former Texaco and Unocal programs totaled approximately 700,000 equivalent shares as of December 31, 2006. A liability of \$16 was recorded for these awards.

Broad-Based Employee Stock Options In addition to the plans described above, Chevron granted all eligible employees stock options or equivalents in 1998. The options vested after two years, in February 2000, and expire after 10 years, in February 2008. A total of 9,641,600 options were awarded with an exercise price of \$38.16 per share.

The fair value of each option on the date of grant was estimated at \$9.54 using the Black-Scholes model for the preceding 10 years. The assumptions used in the model, based on a 10-year average, were: a risk-free interest rate of 7 percent, a dividend yield of 4.2 percent, an expected life of seven years and a volatility of 24.7 percent.

At January 1, 2006, the number of broad-based employee stock options outstanding was 1,682,904. During 2006, exercises of 354,845 shares and forfeitures of 22,000 shares reduced outstanding options to 1,306,059. As of December 31, 2006, these instruments had an aggregate intrinsic value of \$46 and the remaining contractual term of these options was 1.1 years. The total intrinsic value of these options exercised during 2006, 2005 and 2004 was \$10, \$9 and \$16, respectively.

NOTE 23.

OTHER CONTINGENCIES AND COMMITMENTS

Income Taxes The company calculates its income tax expense and liabilities quarterly. 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 calculated. The U.S. federal income tax liabilities have been settled through 1996 for Chevron Corporation, 1997 for Unocal Corporation (Unocal) and 2001 for Texaco Corporation (Texaco). California franchise tax liabilities have been

settled through 1991 for Chevron, 1998 for Unocal 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, 2006, the company and its subsidiaries provided guarantees, either directly or indirectly, of \$296 for notes and other contractual obligations of affiliated companies and \$131 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.

The \$296 in guarantees provided to affiliates related to borrowings for capital projects. These guarantees were undertaken to achieve lower interest rates and generally cover the construction periods of the capital projects. Included in these amounts are the company's guarantees of \$214 associated with a construction completion guarantee for the debt financing of the company's equity interest in the Baku-Tbilisi-Ceyhan (BTC) crude oil pipeline project. Substantially all of the \$296 guaranteed will expire between 2007 and 2011, with the remaining 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.

The \$131 in guarantees provided on behalf of third parties related to construction loans to governments of certain of the company's international upstream operations. Substantially all of the \$131 in guarantees expire by 2011, with the remainder expiring by 2015. 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.

At December 31, 2006, Chevron also had outstanding guarantees for about \$120 of Equilon debt and leases. Following the February 2002 disposition of its interest in Equilon, the company received an indemnification from Shell 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 2007 through 2011 period, with the guarantees of the remaining amounts expiring by 2019.

Indemnifications The company 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 company would be required to perform if the indemnified liabilities become actual losses. Were that to occur, the company could be required to make future payments up to \$300.

NOTE 23. OTHER CONTINGENCIES AND COMMITMENTS - Continued

Through the end of 2006, the company paid approximately \$48 under these indemnities and continues to be obligated for possible additional indemnification payments in the future.

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 period of Texaco's ownership interest 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 indemnities must be asserted either as early as February 2007, or no later than February 2009, and claims relating to Motiva indemnities must be asserted either as early as February 2007, or no later than February 2012. Under the terms of these 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 posts 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 applicable incident.

In the acquisition of Unocal, the company assumed certain indemnities relating to contingent environmental liabilities associated with assets that were sold in 1997. Under the indemnification agreement, the company's liability is unlimited until April 2022, when the liability expires. The acquirer shares in certain environmental remediation costs up to a maximum obligation of \$200, which had not been reached as of December 31, 2006.

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, 2006, approximately \$1,200, representing about 7 percent of Chevron's total current accounts and notes receivables balance, were securitized. Chevron's total estimated financial exposure under these securitizations at December 31, 2006, was approximately \$80. These arrangements have the effect of accelerating Chevron's collection of the securitized amounts. In the event that the SPEs experience major defaults in the collection of receivables, Chevron believes that it would have no loss exposure connected with third-party investments in these securitizations.

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities relating to long-term unconditional purchase obligations and commitments, including throughput 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, drilling rigs, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate approximate amounts of required payments under these various commitments are: 2007 – \$3,200; 2008 – \$1,700; 2009 – \$2,100; 2010 – \$1,900; 2011 – \$900; 2012 and after – \$4,100. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately \$3,000 in 2006, \$2,100 in 2005 and \$1,600 in 2004.

Minority Interests The company has commitments of \$209 related to minority interests in subsidiary companies.

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, federal Superfund sites and analogous sites under state laws, refineries, crude oil fields, service stations, terminals, land development areas, and mining operations, whether operating, closed or divested. These future costs are not fully determinable 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 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 chemical companies.

Chevron's environmental reserve as of December 31, 2006, was \$1,441. Included in this balance were remediation activities of 242 sites for which the company had been identified as a potentially responsible party or otherwise involved in the remediation by the U.S. Environmental Protection Agency (EPA) or other regulatory agencies under the provisions of the federal Superfund law or analogous state laws. The company's remediation

reserve for these sites at year-end 2006 was \$122. The federal Superfund law and analogous state laws provide for joint and several liability for all responsible parties. Any future actions by the EPA or other regulatory agencies to require Chevron 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.

Of the remaining year-end 2006 environmental reserves balance of \$1,319, \$834 related to approximately 2,250 sites for the company's U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals) and pipelines. The remaining \$485 was associated with various sites in the international downstream (\$117), upstream (\$252), chemicals (\$61) and other (\$55). Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company's plans and activities to remediate soil or groundwater contamination or both. These and other activities include one or more of the following: site assessment; soil excavation; offsite disposal of contaminants; onsite containment, remediation and/or extraction of petroleum hydrocarbon liquid and vapor from soil; groundwater extraction and treatment; and monitoring of the natural attenuation of the contaminants.

The company manages environmental liabilities under specific sets of regulatory requirements, which in the United States include the Resource Conservation and Recovery Act and various state or local regulations. No single remediation site at year-end 2006 had a recorded liability that was material to the company's financial position, results of operations 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 not fully determinable 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.

Effective January 1, 2003, the company implemented FASB 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 of approximately \$5,800 for asset retirement obligations at year-end 2006 related primarily to upstream and mining properties. Refer to Note 24 on page 82 for a discussion of the company's Asset Retirement Obligations.

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.

Global Operations Chevron and its affiliates conduct business activities in approximately 180 countries. Besides the United States, the company and its affiliates have significant operations in the following countries: Angola, Argentina, Australia, Azerbaijan, Bangladesh, Brazil, Cambodia, Canada, Chad, China, Colombia, Democratic Republic of the Congo, Denmark, France, India, Indonesia, Kazakhstan, Myanmar, the Netherlands, Nigeria, Norway, the Partitioned Neutral Zone between Kuwait and Saudi Arabia, the Philippines, Republic of the Congo, Singapore, South Africa, South Korea, Thailand, Trinidad and Tobago, the United Kingdom, Venezuela and Vietnam.

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 governments to increase public ownership of the company's partially or wholly owned businesses or assets or to impose additional taxes or royalties on the company's operations or both.

In certain locations, 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, acts of violence or strained relations between a 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 crude oil and natural 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 Chevron'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. For this range of settlement, Chevron estimates its maximum possible net before-tax liability at approximately \$200, and the possible maximum net amount that could be owed to Chevron is estimated at about

NOTE 23. OTHER CONTINGENCIES AND COMMITMENTS - Continued

\$150. The timing of the settlement and the exact amount within this range of estimates are uncertain.

Other Contingencies Chevron receives claims from and submits claims to customers; trading partners; U.S. federal, state and local regulatory bodies; 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.

ASSET RETIREMENT OBLIGATIONS

The company accounts for asset retirement obligations in accordance with Financial Accounting Standards Board Statement (FASB) No. 143, *Accounting for Asset Retirement Obligations* (FAS 143). This accounting standard applies to the fair value of a liability for an asset retirement obligation (ARO) 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 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. In 2005, the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations - An Interpretation of FASB Statement No. 143* (FIN 47), which was effective for the company on December 31, 2005. FIN 47 clarifies that the phrase "conditional asset retirement obligation," as used in FAS 143, refers to a legal obligation to perform asset retirement activity for which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the company. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Uncertainty about the timing and/or method of settlement of a conditional ARO should be factored into the measurement of the liability when sufficient information exists. FAS 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an ARO. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO. In adopting FIN 47, the company did not recognize any additional liabilities for conditional AROs due to an inability to reasonably estimate the

fair value of those obligations because of their indeterminate settlement dates.

FAS 143 and FIN 47 primarily affect the company's accounting for crude oil and natural gas producing assets. No significant AROs associated with any legal obligations to retire refining, marketing and transportation (downstream) and chemical long-lived assets have been 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.

The following table indicates the changes to the company's before-tax asset retirement obligations in 2006, 2005 and 2004:

	2006	2005	2004
Balance at January 1	\$ 4,304	\$ 2,878	\$ 2,856
Liabilities assumed in the			
Unocal acquisition	—	1,216	—
Liabilities incurred	153	90	37
Liabilities settled	(387)	(172)	(426)
Accretion expense	275	187	93
Revisions in estimated cash flows	1,428*	105	318
Balance at December 31	\$ 5,773	\$ 4,304	\$ 2,878

*Includes \$1,128 associated with estimated costs to dismantle and abandon wells and facilities damaged by the 2005 hurricanes in the Gulf of Mexico.

NOTE 25.

COMMON STOCK SPLIT

In September 2004, the company effected a two-for-one stock split in the form of a stock dividend. The total number of authorized common stock shares and associated par value were unchanged by this action. All per-share amounts in the financial statements reflect the stock split for all periods presented. The effect of the common stock split is reflected on the Consolidated Balance Sheet in "Common stock" and "Capital in excess of par value."

NOTE 26.

OTHER FINANCIAL INFORMATION

Net income in 2004 included gains of approximately \$1,200 relating to the sale of nonstrategic upstream properties. Of this amount, \$257 related to assets classified as discontinued operations.

Other financial information is as follows:

	Year ended December 31		
	2006	2005	2004
Total financing interest and debt costs	\$ 608	\$ 542	\$ 450
Less: Capitalized interest	157	60	44
Interest and debt expense	\$ 451	\$ 482	\$ 406
Research and development expenses	\$ 468	\$ 316	\$ 242
Foreign currency effects*	\$(219)	\$ (61)	\$ (81)

*Includes \$15, \$(2) and \$(13) in 2006, 2005 and 2004, respectively, for the company's share of equity affiliates' foreign currency effects.

The excess of market value over the carrying value of inventories for which the Last-In, First-Out (LIFO) method is used was \$6,010, \$4,846 and \$3,036 at December 31, 2006, 2005 and 2004, respectively. Market value is generally based on average acquisition costs for the year. LIFO profits of \$82, \$34 and \$36 were included in net income for the years 2006, 2005 and 2004, respectively.

NOTE 27.

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 Chevron 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 (refer to Note 22, "Stock Options and Other Share-Based Compensation" beginning on page 77). The table on the following page sets forth the computation of basic and diluted EPS:

NOTE 27. EARNINGS PER SHARE - Continued

	Year ended December 31		
	2006	2005	2004
BASIC EPS CALCULATION			
Income from continuing operations	\$ 17,138	\$ 14,099	\$ 13,034
Add: Dividend equivalents paid on stock units	1	2	3
Income from continuing operations available to common stockholders	\$ 17,139	\$ 14,101	\$ 13,037
Income from discontinued operations	—	—	294
Net income available to common stockholders – Basic	\$ 17,139	\$ 14,101	\$ 13,331
Weighted-average number of common shares outstanding*	2,185	2,143	2,114
Add: Deferred awards held as stock units	1	1	2
Total weighted-average number of common shares outstanding	2,186	2,144	2,116
Per share of common stock			
Income from continuing operations available to common stockholders	\$ 7.84	\$ 6.58	\$ 6.16
Income from discontinued operations	—	—	0.14
Net income – Basic	\$ 7.84	\$ 6.58	\$ 6.30
DILUTED EPS CALCULATION			
Income from continuing operations	\$ 17,138	\$ 14,099	\$ 13,034
Add: Dividend equivalents paid on stock units	1	2	3
Add: Dilutive effects of employee stock-based awards	—	2	1
Income from continuing operations available to common stockholders	\$ 17,139	\$ 14,103	\$ 13,038
Income from discontinued operations	—	—	294
Net income available to common stockholders – Diluted	\$ 17,139	\$ 14,103	\$ 13,332
Weighted-average number of common shares outstanding*	2,185	2,143	2,114
Add: Deferred awards held as stock units	1	1	2
Add: Dilutive effect of employee stock-based awards	11	11	6
Total weighted-average number of common shares outstanding	2,197	2,155	2,122
Per share of common stock			
Income from continuing operations available to common stockholders	\$ 7.80	\$ 6.54	\$ 6.14
Income from discontinued operations	—	—	0.14
Net income – Diluted	\$ 7.80	\$ 6.54	\$ 6.28

*Share amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

FIVE-YEAR OPERATING SUMMARY¹

Unaudited

Worldwide – Includes Equity in Affiliates

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

	2006	2005	2004	2003	2002
UNITED STATES					
Gross production of crude oil and natural gas liquids ¹	510	499	555	619	665
Net production of crude oil and natural gas liquids ¹	462	455	505	562	602
Gross production of natural gas	2,115	1,860	2,191	2,619	2,945
Net production of natural gas ²	1,810	1,634	1,873	2,228	2,405
Net production of oil equivalents	763	727	817	933	1,003
Refinery input	939	845	914	951	979
Sales of refined products ³	1,494	1,473	1,506	1,436	1,600
Sales of natural gas liquids	124	151	177	194	241
Total sales of petroleum products	1,618	1,624	1,683	1,630	1,841
Sales of natural gas	7,051	5,449	4,518	4,304	5,891
INTERNATIONAL					
Gross production of crude oil and natural gas liquids ¹	1,739	1,676	1,645	1,681	1,765
Net production of crude oil and natural gas liquids ¹	1,270	1,214	1,205	1,246	1,295
Other produced volumes	109	143	140	114	97
Gross production of natural gas	3,767	2,726	2,203	2,203	2,120
Net production of natural gas ²	3,146	2,599	2,085	2,064	1,971
Net production of oil equivalents	1,904	1,790	1,692	1,704	1,720
Refinery input	1,050	1,038	1,044	1,040	1,100
Sales of refined products ^{3,4}	2,127	2,252	2,368	2,274	2,148
Sales of natural gas liquids ⁴	102	120	118	118	142
Total sales of petroleum products ⁴	2,229	2,372	2,486	2,392	2,290
Sales of natural gas ⁴	3,478	2,450	2,040	2,106	3,286
TOTAL WORLDWIDE					
Gross production of crude oil and natural gas liquids ¹	2,249	2,175	2,200	2,300	2,430
Net production of crude oil and natural gas liquids ¹	1,732	1,669	1,710	1,808	1,897
Other produced volumes	109	143	140	114	97
Gross production of natural gas	5,882	4,586	4,394	4,822	5,065
Net production of natural gas ²	4,956	4,233	3,958	4,292	4,376
Net production of oil equivalents	2,667	2,517	2,509	2,637	2,723
Refinery input	1,989	1,883	1,958	1,991	2,079
Sales of refined products ^{3,4}	3,621	3,725	3,874	3,710	3,748
Sales of natural gas liquids ⁴	226	271	295	312	383
Total sales of petroleum products ⁴	3,847	3,996	4,169	4,022	4,131
Sales of natural gas ⁴	10,529	7,899	6,558	6,410	9,177
Worldwide – Excludes Equity in Affiliates					
Number of wells completed (net) ⁵					
Oil and gas	1,575	1,365	1,307	1,472	1,349
Dry	32	26	24	36	49
Productive oil and gas wells (net) ⁵	50,695	49,508	44,707	48,155	50,320

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 Includes natural gas consumed in operations:

United States	56	48	50	65	64
International	419	356	293	268	256
Total	475	404	343	333	320

³ Includes volumes for buy/sell contracts (MBPD):

United States	26	88	84	90	101
International	24	129	96	104	96

⁴ 2002 through 2005 conformed to the 2006 presentation.

⁵ Net wells include wholly owned and the sum of fractional interests in partially owned wells. 2005 conformed to 2006 presentation.

FIVE-YEAR FINANCIAL SUMMARY

Unaudited

Millions of dollars, except per-share amounts

	2006	2005	2004	2003	2002
COMBINED STATEMENT OF INCOME DATA					
REVENUES AND OTHER INCOME					
Total sales and other operating revenues	\$ 204,892	\$ 193,641	\$ 150,865	\$ 119,575	\$ 98,340
Income from equity affiliates and other income	5,226	4,559	4,435	1,702	197
TOTAL REVENUES AND OTHER INCOME	210,118	198,200	155,300	121,277	98,537
TOTAL COSTS AND OTHER DEDUCTIONS					
	178,142	173,003	134,749	108,601	94,437
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	31,976	25,197	20,551	12,676	4,100
INCOME TAX EXPENSE	14,838	11,098	7,517	5,294	2,998
INCOME FROM CONTINUING OPERATIONS	17,138	14,099	13,034	7,382	1,102
INCOME FROM DISCONTINUED OPERATIONS	—	—	294	44	30
INCOME BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	17,138	14,099	13,328	7,426	1,132
Cumulative effect of changes in accounting principles	—	—	—	(196)	—
NET INCOME	\$ 17,138	\$ 14,099	\$ 13,328	\$ 7,230	\$ 1,132
PER SHARE OF COMMON STOCK¹					
INCOME FROM CONTINUING OPERATIONS²					
— Basic	\$ 7.84	\$ 6.58	\$ 6.16	\$ 3.55	\$ 0.52
— Diluted	\$ 7.80	\$ 6.54	\$ 6.14	\$ 3.55	\$ 0.52
INCOME FROM DISCONTINUED OPERATIONS					
— Basic	\$ —	\$ —	\$ 0.14	\$ 0.02	\$ 0.01
— Diluted	\$ —	\$ —	\$ 0.14	\$ 0.02	\$ 0.01
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES					
— Basic	\$ —	\$ —	\$ —	\$ (0.09)	\$ —
— Diluted	\$ —	\$ —	\$ —	\$ (0.09)	\$ —
NET INCOME²					
— Basic	\$ 7.84	\$ 6.58	\$ 6.30	\$ 3.48	\$ 0.53
— Diluted	\$ 7.80	\$ 6.54	\$ 6.28	\$ 3.48	\$ 0.53
CASH DIVIDENDS PER SHARE	\$ 2.01	\$ 1.75	\$ 1.53	\$ 1.43	\$ 1.40
COMBINED BALANCE SHEET DATA (AT DECEMBER 31)					
Current assets	\$ 36,304	\$ 34,336	\$ 28,503	\$ 19,426	\$ 17,776
Noncurrent assets	96,324	91,497	64,705	62,044	59,583
TOTAL ASSETS	132,628	125,833	93,208	81,470	77,359
Short-term debt	2,159	739	816	1,703	5,358
Other current liabilities	26,250	24,272	17,979	14,408	14,518
Long-term debt and capital lease obligations	7,679	12,131	10,456	10,894	10,911
Other noncurrent liabilities	27,605	26,015	18,727	18,170	14,968
TOTAL LIABILITIES	63,693	63,157	47,978	45,175	45,755
STOCKHOLDERS' EQUITY	\$ 68,935	\$ 62,676	\$ 45,230	\$ 36,295	\$ 31,604

¹ Per-share amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

² The amount in 2003 includes a benefit of \$0.08 for the company's share of a capital stock transaction of its Dynegy affiliate, which, under the applicable accounting rules, was recorded directly to retained earnings and not included in net income for the period.

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES

Unaudited

In accordance with Statement of FAS 69, *Disclosures About Oil and Gas Producing Activities*, 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 the Congo and Democratic Republic of the Congo. The Asia-Pacific

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

Millions of dollars	Consolidated Companies												Affiliated Companies	
	United States				International									
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other		
YEAR ENDED DEC. 31, 2006														
Exploration														
Wells	\$ -	\$ 493	\$ 22	\$ 515	\$ 151	\$ 121	\$ 20	\$ 246	\$ 538	\$ 1,053	\$ 25	\$ -		
Geological and geophysical	-	96	8	104	180	53	12	92	337	441	-	-		
Rentals and other	-	116	16	132	48	140	58	50	296	428	-	-		
Total exploration	-	705	46	751	379	314	90	388	1,171	1,922	25	-		
Property acquisitions														
Proved ²	6	152	-	158	1	10	-	15	26	184	-	581		
Unproved	1	47	10	58	-	1	-	135	136	194	-	-		
Total property acquisitions	7	199	10	216	1	11	-	150	162	378	-	581		
Development ³	686	1,632	868	3,186	2,890	1,788	460	1,019	6,157	9,343	671	25		
TOTAL COSTS INCURRED	\$ 693	\$ 2,536	\$ 924	\$ 4,153	\$ 3,270	\$ 2,113	\$ 550	\$ 1,557	\$ 7,490	\$ 11,643	\$ 696	\$ 606		
YEAR ENDED DEC. 31, 2005 ⁴														
Exploration														
Wells	\$ -	\$ 452	\$ 24	\$ 476	\$ 105	\$ 38	\$ 9	\$ 201	\$ 353	\$ 829	\$ -	\$ -		
Geological and geophysical	-	67	-	67	96	28	10	68	202	269	-	-		
Rentals and other	-	93	8	101	24	58	12	72	166	267	-	-		
Total exploration	-	612	32	644	225	124	31	341	721	1,365	-	-		
Property acquisitions														
Proved – Unocal ²	-	1,608	2,388	3,996	30	6,609	637	1,790	9,066	13,062	-	-		
Proved – Other ²	-	6	10	16	2	2	-	12	16	32	-	-		
Unproved – Unocal	-	819	295	1,114	11	2,209	821	38	3,079	4,193	-	-		
Unproved – Other	-	17	6	23	67	-	-	28	95	118	-	-		
Total property acquisitions	-	2,450	2,699	5,149	110	8,820	1,458	1,868	12,256	17,405	-	-		
Development ³	507	680	601	1,788	1,892	1,088	382	726	4,088	5,876	767	43		
TOTAL COSTS INCURRED	\$ 507	\$ 3,742	\$ 3,332	\$ 7,581	\$ 2,227	\$ 10,032	\$ 1,871	\$ 2,935	\$ 17,065	\$ 24,646	\$ 767	\$ 43		
YEAR ENDED DEC. 31, 2004 ⁴														
Exploration														
Wells	\$ -	\$ 388	\$ -	\$ 388	\$ 116	\$ 25	\$ 2	\$ 127	\$ 270	\$ 658	\$ -	\$ -		
Geological and geophysical	-	47	2	49	103	10	12	46	171	220	-	-		
Rentals and other	-	43	3	46	52	47	1	53	153	199	-	-		
Total exploration	-	478	5	483	271	82	15	226	594	1,077	-	-		
Property acquisitions														
Proved ²	-	6	1	7	111	16	-	4	131	138	-	-		
Unproved	-	29	-	29	82	-	-	5	87	116	-	-		
Total property acquisitions	-	35	1	36	193	16	-	9	218	254	-	-		
Development ³	413	466	375	1,254	1,057	620	403	627	2,707	3,961	896	208		
TOTAL COSTS INCURRED	\$ 413	\$ 979	\$ 381	\$ 1,773	\$ 1,521	\$ 718	\$ 418	\$ 862	\$ 3,519	\$ 5,292	\$ 896	\$ 208		

¹ Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. See Note 24, "Asset Retirement Obligations," on page 82.

² Includes wells, equipment and facilities associated with proved reserves. Does not include properties acquired through property exchanges.

³ Includes \$160, \$160 and \$63 costs incurred prior to assignment of proved reserves in 2006, 2005 and 2004, respectively.

⁴ 2005 and 2004 presentation conformed to 2006.

geographic area includes activities principally in Australia, Azerbaijan, Bangladesh, China, Kazakhstan, Myanmar, the Partitioned Neutral Zone between Kuwait and Saudi Arabia, the Philippines, and Thailand. The international "Other" geographic category includes activities in Argentina, Brazil, Canada, Colombia, Denmark, the Netherlands, Norway, Trinidad and Tobago, Venezuela, the United Kingdom, and other countries. Amounts for TCO represent Chevron's 50 percent equity share of Tengizchevroil, an exploration and

production partnership in the Republic of Kazakhstan. The affiliated companies "Other" amounts are composed of a 30 percent equity share of Hamaca, an exploration and production partnership in Venezuela and, effective October 2006, Chevron's 39 percent interest and 25 percent interest in Petroboscan and Petroindependiente, respectively. These joint stock companies are involved in the development of the Boscan and LL-652 fields in Venezuela, respectively.

TABLE II - CAPITALIZED COSTS RELATED TO OIL AND GAS PRODUCING ACTIVITIES

Millions of dollars	Consolidated Companies											
	United States				International						Affiliated Companies	
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
AT DEC. 31, 2006												
Unproved properties	\$ 770	\$ 1,007	\$ 370	\$ 2,147	\$ 342	\$ 2,373	\$ 707	\$ 1,082	\$ 4,504	\$ 6,651	\$ 112	\$ –
Proved properties and related producing assets	9,960	18,464	12,284	40,708	9,943	15,486	7,110	10,461	43,000	83,708	2,701	1,096
Support equipment	189	212	226	627	745	240	1,093	364	2,442	3,069	611	–
Deferred exploratory wells	–	343	7	350	231	217	149	292	889	1,239	–	–
Other uncompleted projects	370	2,188	–	2,558	4,299	1,546	493	917	7,255	9,813	2,493	40
GROSS CAP. COSTS	11,289	22,214	12,887	46,390	15,560	19,862	9,552	13,116	58,090	104,480	5,917	1,136
Unproved properties valuation	738	52	29	819	189	74	14	337	614	1,433	22	–
Proved producing properties – Depreciation and depletion	7,082	14,468	6,880	28,430	4,794	5,273	4,971	6,087	21,125	49,555	541	109
Support equipment depreciation	125	111	130	366	400	102	522	238	1,262	1,628	242	–
Accumulated provisions	7,945	14,631	7,039	29,615	5,383	5,449	5,507	6,662	23,001	52,616	805	109
NET CAPITALIZED COSTS	\$ 3,344	\$ 7,583	\$ 5,848	\$ 16,775	\$ 10,177	\$ 14,413	\$ 4,045	\$ 6,454	\$ 35,089	\$ 51,864	\$ 5,112	\$ 1,027
AT DEC. 31, 2005*												
Unproved properties	\$ 769	\$ 1,077	\$ 397	\$ 2,243	\$ 407	\$ 2,287	\$ 645	\$ 983	\$ 4,322	\$ 6,565	\$ 108	\$ –
Proved properties and related producing assets	9,546	18,283	11,467	39,296	8,404	14,928	6,613	9,627	39,572	78,868	2,264	1,213
Support equipment	204	193	230	627	715	426	1,217	356	2,714	3,341	549	–
Deferred exploratory wells	–	284	5	289	245	154	173	248	820	1,109	–	–
Other uncompleted projects	149	782	209	1,140	2,878	790	427	946	5,041	6,181	2,332	–
GROSS CAP. COSTS	10,668	20,619	12,308	43,595	12,649	18,585	9,075	12,160	52,469	96,064	5,253	1,213
Unproved properties valuation	736	90	22	848	162	69	–	318	549	1,397	17	–
Proved producing properties – Depreciation and depletion	6,818	14,067	6,049	26,934	4,266	4,016	4,105	5,720	18,107	45,041	460	90
Support equipment depreciation	140	119	149	408	317	88	680	222	1,307	1,715	213	–
Accumulated provisions	7,694	14,276	6,220	28,190	4,745	4,173	4,785	6,260	19,963	48,153	690	90
NET CAPITALIZED COSTS	\$ 2,974	\$ 6,343	\$ 6,088	\$ 15,405	\$ 7,904	\$ 14,412	\$ 4,290	\$ 5,900	\$ 32,506	\$ 47,911	\$ 4,563	\$ 1,123

*Conformed to 2006 presentation.

TABLE II - CAPITALIZED COSTS RELATED TO OIL AND GAS PRODUCING ACTIVITIES - Continued

Millions of dollars	Consolidated Companies											Affiliated Companies	
	United States				International								
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other	
AT DEC. 31, 2004 ^{1,2}													
Unproved properties	\$ 769	\$ 380	\$ 109	\$ 1,258	\$ 322	\$ 211	\$ –	\$ 970	\$ 1,503	\$ 2,761	\$ 108	\$ –	
Proved properties and related producing assets	9,198	16,814	8,730	34,742	7,394	7,598	5,731	9,253	29,976	64,718	2,183	963	
Support equipment	211	175	208	594	513	127	1,123	361	2,124	2,718	496	–	
Deferred exploratory wells	–	225	–	225	213	81	–	152	446	671	–	–	
Other uncompleted projects	91	400	169	660	2,050	605	351	391	3,397	4,057	1,749	149	
GROSS CAP. COSTS	10,269	17,994	9,216	37,479	10,492	8,622	7,205	11,127	37,446	74,925	4,536	1,112	
Unproved properties valuation	734	111	27	872	118	67	–	294	479	1,351	15	–	
Proved producing properties – Depreciation and depletion	6,718	13,736	5,681	26,135	3,881	3,171	3,576	5,081	15,709	41,844	428	43	
Support equipment depreciation	148	107	139	394	268	60	658	206	1,192	1,586	190	–	
Accumulated provisions	7,600	13,954	5,847	27,401	4,267	3,298	4,234	5,581	17,380	44,781	633	43	
NET CAPITALIZED COSTS	\$ 2,669	\$ 4,040	\$ 3,369	\$ 10,078	\$ 6,225	\$ 5,324	\$ 2,971	\$ 5,546	\$ 20,066	\$ 30,144	\$ 3,903	\$ 1,069	

¹ Includes assets held for sale.

² Conformed to 2006 presentation.

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 2006, 2005 and 2004 are shown in the following table. Net income from exploration and production activities as reported on page 62 reflects income taxes computed on an effective rate basis.

In accordance with FAS 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 page 62.

Millions of dollars	Consolidated Companies										Affiliated Companies	
	United States				International						TCO	
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
YEAR ENDED DEC. 31, 2006												
Revenues from net production												
Sales	\$ 308	\$ 1,845	\$ 2,976	\$ 5,129	\$ 2,377	\$ 4,938	\$ 1,001	\$ 2,814	\$ 11,130	\$ 16,259	\$ 2,861	\$ 598
Transfers	4,072	2,317	2,046	8,435	5,264	4,084	2,211	2,848	14,407	22,842	—	—
Total	4,380	4,162	5,022	13,564	7,641	9,022	3,212	5,662	25,537	39,101	2,861	598
Production expenses excluding taxes	(889)	(765)	(1,057)	(2,711)	(640)	(740)	(728)	(664)	(2,772)	(5,483)	(202)	(42)
Taxes other than on income	(84)	(57)	(442)	(583)	(57)	(231)	(1)	(60)	(349)	(932)	(28)	(6)
Proved producing properties: Depreciation and depletion	(275)	(1,096)	(763)	(2,134)	(579)	(1,475)	(666)	(703)	(3,423)	(5,557)	(114)	(33)
Accretion expense ²	(11)	(80)	(39)	(130)	(26)	(30)	(23)	(49)	(128)	(258)	(1)	—
Exploration expenses	—	(407)	(24)	(431)	(296)	(209)	(110)	(318)	(933)	(1,364)	(25)	—
Unproved properties valuation	(3)	(73)	(8)	(84)	(28)	(15)	(14)	(27)	(84)	(168)	—	—
Other income (expense) ³	1	(732)	254	(477)	(435)	(475)	50	385	(475)	(952)	8	(50)
Results before income taxes	3,119	952	2,943	7,014	5,580	5,847	1,720	4,226	17,373	24,387	2,499	467
Income tax expense	(1,169)	(357)	(1,103)	(2,629)	(4,740)	(3,224)	(793)	(2,151)	(10,908)	(13,537)	(750)	(174)
RESULTS OF PRODUCING OPERATIONS	\$ 1,950	\$ 595	\$ 1,840	\$ 4,385	\$ 840	\$ 2,623	\$ 927	\$ 2,075	\$ 6,465	\$ 10,850	\$ 1,749	\$ 293
YEAR ENDED DEC. 31, 2005												
Revenues from net production												
Sales	\$ 337	\$ 1,576	\$ 3,174	\$ 5,087	\$ 2,142	\$ 2,941	\$ 539	\$ 2,668	\$ 8,290	\$ 13,377	\$ 2,307	\$ 666
Transfers	3,497	2,127	1,395	7,019	3,615	3,179	1,986	2,607	11,387	18,406	—	—
Total	3,834	3,703	4,569	12,106	5,757	6,120	2,525	5,275	19,677	31,783	2,307	666
Production expenses excluding taxes	(916)	(638)	(777)	(2,331)	(558)	(570)	(660)	(596)	(2,384)	(4,715)	(152)	(82)
Taxes other than on income	(65)	(41)	(384)	(490)	(48)	(189)	(1)	(195)	(433)	(923)	(27)	—
Proved producing properties: Depreciation and depletion	(253)	(936)	(520)	(1,709)	(414)	(852)	(550)	(672)	(2,488)	(4,197)	(83)	(46)
Accretion expense ²	(13)	(35)	(46)	(94)	(22)	(20)	(15)	(25)	(82)	(176)	(1)	—
Exploration expenses	—	(307)	(13)	(320)	(117)	(90)	(26)	(190)	(423)	(743)	—	—
Unproved properties valuation	(3)	(32)	(4)	(39)	(50)	(8)	—	(24)	(82)	(121)	—	—
Other income (expense) ³	2	(354)	(140)	(492)	(243)	(182)	182	280	37	(455)	(9)	8
Results before income taxes	2,586	1,360	2,685	6,631	4,305	4,209	1,455	3,853	13,822	20,453	2,035	546
Income tax expense	(913)	(482)	(953)	(2,348)	(3,430)	(2,264)	(644)	(1,938)	(8,276)	(10,624)	(611)	(186)
RESULTS OF PRODUCING OPERATIONS	\$ 1,673	\$ 878	\$ 1,732	\$ 4,283	\$ 875	\$ 1,945	\$ 811	\$ 1,915	\$ 5,546	\$ 9,829	\$ 1,424	\$ 360

¹ The value of owned production consumed in operations 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 Represents accretion of ARO liability. Refer to Note 24, "Asset Retirement Obligations," on page 82.

³ Includes foreign currency gains and losses, gains and losses on property dispositions, and income from operating and technical service agreements.

TABLE III - RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES¹ - Continued

	Consolidated Companies											
	United States				International							
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	Affiliated Companies	
Millions of dollars											TCO	Other
YEAR ENDED DEC. 31, 2004												
Revenues from net production												
Sales	\$ 251	\$ 1,925	\$ 2,163	\$ 4,339	\$ 1,321	\$ 1,191	\$ 256	\$ 2,481	\$ 5,249	\$ 9,588	\$ 1,619	\$ 205
Transfers	2,651	1,768	1,224	5,643	2,645	2,265	1,613	1,903	8,426	14,069	—	—
Total	2,902	3,693	3,387	9,982	3,966	3,456	1,869	4,384	13,675	23,657	1,619	205
Production expenses excluding taxes	(710)	(547)	(697)	(1,954)	(574)	(431)	(591)	(544)	(2,140)	(4,094)	(143)	(53)
Taxes other than on income	(57)	(45)	(321)	(423)	(24)	(138)	(1)	(134)	(297)	(720)	(26)	—
Proved producing properties:												
Depreciation and depletion	(232)	(774)	(384)	(1,390)	(367)	(401)	(393)	(798)	(1,959)	(3,349)	(104)	(4)
Accretion expense ²	(12)	(25)	(19)	(56)	(22)	(8)	(13)	11	(32)	(88)	(2)	—
Exploration expenses	—	(227)	(6)	(233)	(235)	(69)	(17)	(144)	(465)	(698)	—	—
Unproved properties valuation	(3)	(29)	(4)	(36)	(23)	(8)	—	(25)	(56)	(92)	—	—
Other income (expense) ³	14	24	474	512	49	10	12	1,028	1,099	1,611	(7)	(58)
Results before income taxes	1,902	2,070	2,430	6,402	2,770	2,411	866	3,778	9,825	16,227	1,337	90
Income tax expense	(703)	(765)	(898)	(2,366)	(2,036)	(1,395)	(371)	(1,759)	(5,561)	(7,927)	(401)	—
RESULTS OF PRODUCING OPERATIONS												
OPERATIONS	\$ 1,199	\$ 1,305	\$ 1,532	\$ 4,036	\$ 734	\$ 1,016	\$ 495	\$ 2,019	\$ 4,264	\$ 8,300	\$ 936	\$ 90

¹ The value of owned production consumed in operations 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 Represents accretion of ARO liability. Refer to Note 24, "Asset Retirement Obligations," on page 82.

³ Includes foreign currency gains and losses, gains and losses on property dispositions, and income from operating and technical service agreements.

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

	Consolidated Companies											Affiliated Companies TCOOther	
	United States				International								
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total			
YEAR ENDED DEC. 31, 2006													
Average sales prices													
Liquids, per barrel	\$ 55.20	\$ 60.35	\$ 55.80	\$ 56.66	\$ 61.53	\$ 57.05	\$ 52.23	\$ 57.31	\$ 57.92	\$ 57.53	\$ 56.80	\$ 37.26	
Natural gas, per thousand cubic feet	6.08	7.20	5.73	6.29	0.06	3.44	7.12	4.03	3.88	4.85	0.77	0.36	
Average production costs, per barrel	10.94	9.59	9.26	9.85	5.13	3.36	11.44	5.23	5.17	6.76	3.31	2.51	
YEAR ENDED DEC. 31, 2005													
Average sales prices													
Liquids, per barrel	\$ 45.24	\$ 48.80	\$ 48.29	\$ 46.97	\$ 50.54	\$ 45.88	\$ 44.40	\$ 48.61	\$ 47.83	\$ 47.56	\$ 45.59	\$ 45.89	
Natural gas, per thousand cubic feet	6.94	8.43	6.90	7.43	0.04	3.59	5.74	3.31	3.48	5.18	0.61	0.26	
Average production costs, per barrel	10.74	8.55	7.57	8.88	4.72	3.38	11.28	4.32	4.93	6.32	2.45	5.53	
YEAR ENDED DEC. 31, 2004													
Average sales prices													
Liquids, per barrel	\$ 33.43	\$ 34.69	\$ 34.61	\$ 34.12	\$ 34.85	\$ 31.34	\$ 31.12	\$ 34.58	\$ 33.33	\$ 33.60	\$ 30.23	\$ 23.32	
Natural gas, per thousand cubic feet	5.18	6.08	5.07	5.51	0.04	3.41	3.88	2.68	2.90	4.27	0.65	0.27	
Average production costs, per barrel	8.14	5.26	6.65	6.60	4.89	3.50	9.69	3.47	4.67	5.43	2.31	6.10	

¹ The value of owned production consumed in operations 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.

TABLE V - RESERVE QUANTITY INFORMATION

Reserves Governance The company has adopted a comprehensive reserves and resource classification system modeled after a system developed and approved by the Society of Petroleum Engineers, the World Petroleum Congress and the American Association of Petroleum Geologists. The system classifies recoverable hydrocarbons into six categories based on their status at the time of reporting – three deemed commercial and three noncommercial. Within the commercial classification are proved reserves and two categories of unproved, probable and possible. The noncommercial categories are also referred to as contingent resources. For reserves estimates to be classified as proved, they must meet all SEC and company standards.

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

Proved reserves are classified as either developed or undeveloped. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods.

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 are estimated by company asset teams composed of earth scientists and engineers. As part of the internal control process related to reserves estimation, the company maintains a Reserves Advisory Committee (RAC) that is chaired by the corporate reserves manager, who is a member of a corporate department that reports directly to the executive vice president responsible for the company's worldwide exploration and production activities. All of the RAC members are knowledgeable in SEC guidelines for proved reserves classification. The RAC coordinates its activities through two operating company-level reserves managers. These two reserves managers are not members of the RAC so as to preserve the corporate-level independence.

The RAC has the following primary responsibilities: provide independent reviews of the business units' recommended reserve changes; confirm that proved reserves are recognized in accordance with SEC guidelines; determine that reserve volumes are calculated using consistent and appropriate standards, procedures and technology; and maintain the *Corporate Reserves Manual*, which provides standardized procedures used corporatewide for classifying and reporting hydrocarbon reserves.

TABLE V - RESERVE QUANTITY INFORMATION - Continued

During the year, the RAC is represented in meetings with each of the company's upstream business units to review and discuss reserve changes recommended by the various asset teams. Major changes are also reviewed with the company's Strategy and Planning Committee and the Executive Committee, whose members include the Chief Executive Officer and the Chief Financial Officer. The company's annual reserve activity is also reviewed with the Board of Directors. If major changes to reserves were to occur between the annual reviews, those matters would also be discussed with the Board.

RAC subteams also conduct in-depth reviews during the year of many of the fields that have the largest proved reserves quantities. These reviews include an examination of the proved-reserve records and documentation of their alignment with the *Corporate Reserves Manual*.

Reserve Quantities At December 31, 2006, oil-equivalent reserves for the company's consolidated operations were 8.6 billion barrels. (Refer to page 24 for the definition of oil-equivalent reserves.) Approximately 28 percent of the total reserves were in the United States. For the company's interests in equity affiliates, oil-equivalent reserves were 3 billion barrels, 80 percent of which were associated with the company's 50 percent ownership in TCO. During the year, the company's Boscan and LL-652 contracts in Venezuela were converted to Empresas Mixtas (i.e., joint stock contractual structures). The company had not previously recorded any reserves for its Boscan operations, but did so this year as a result of the conversion. The conversion of LL-652 reserves was treated as the sale of consolidated company reserves and the acquisition of equity affiliate reserves.

Aside from the TCO operations, no single property accounted for more than 5 percent of company's total oil-equivalent proved reserves. Fewer than 20 other individual properties in the company's portfolio of assets each contained between 1 percent and 5 percent of the company's oil-equivalent proved reserves, which in the aggregate accounted for about 36 percent of the company's proved reserves total. These properties were geographically dispersed, located in the United States, South America, West Africa, the Middle East and the Asia-Pacific region.

In the United States, total oil-equivalent reserves at year-end 2006 were 2.4 billion barrels. Of this amount, 40 percent, 21 percent and 39 percent were located in California, the Gulf of Mexico and other U.S. areas, respectively.

In California, liquids reserves represented 95 percent of the total, with most classified as heavy oil. Because of heavy oil's high viscosity and the need to employ enhanced recovery methods, the producing operations are capital intensive in nature. Most of the company's heavy-oil fields in California employ a continuous steamflooding process.

In the Gulf of Mexico region, liquids represented approximately 64 percent of total oil-equivalent reserves. Production operations are mostly offshore and, as a result, are also capital intensive. Costs include investments in wells, production platforms and other facilities, such as gathering lines and storage facilities.

In other U.S. areas, the reserves were split about equally between liquids and natural gas. For production of crude oil, some fields utilize enhanced recovery methods, including waterflood and CO₂ injection.

The pattern of net reserve changes shown in the following tables, for the three years ending December 31, 2006, is not necessarily indicative of future trends. Apart from acquisitions, the company's ability to add proved reserves is affected by, among other things, events and circumstances that are outside the company's control, such as delays in government permitting, partner approvals of development plans, declines in oil and gas prices, OPEC constraints, geopolitical uncertainties, and civil unrest.

The company's estimated net proved underground oil and natural gas reserves and changes thereto for the years 2004, 2005 and 2006 are shown in the tables on pages 94 and 96.

TABLE V - RESERVE QUANTITY INFORMATION - Continued

NET PROVED RESERVES OF CRUDE OIL, CONDENSATE AND NATURAL GAS LIQUIDS

<i>Millions of barrels</i>	Consolidated Companies										Affiliated Companies	
	United States				International							
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
RESERVES AT JAN. 1, 2004	1,051	435	572	2,058	1,923	796	807	696	4,222	6,280	1,840	479
Changes attributable to:												
Revisions	13	(68)	(2)	(57)	(70)	(43)	(36)	(12)	(161)	(218)	206	(2)
Improved recovery	28	—	6	34	34	—	6	—	40	74	—	—
Extensions and discoveries	—	8	6	14	77	9	—	17	103	117	—	—
Purchases ¹	—	2	—	2	—	—	—	—	—	2	—	—
Sales ²	—	(27)	(103)	(130)	(16)	—	—	(33)	(49)	(179)	—	—
Production	(81)	(56)	(47)	(184)	(115)	(86)	(79)	(101)	(381)	(565)	(52)	(9)
RESERVES AT DEC. 31, 2004³	1,011	294	432	1,737	1,833	676	698	567	3,774	5,511	1,994	468
Changes attributable to:												
Revisions	(23)	(6)	(11)	(40)	(29)	(56)	(108)	(6)	(199)	(239)	(5)	(19)
Improved recovery	57	—	4	61	67	4	42	29	142	203	—	—
Extensions and discoveries	—	37	7	44	53	21	1	65	140	184	—	—
Purchases ¹	—	49	147	196	4	287	20	65	376	572	—	—
Sales ²	(1)	—	(1)	(2)	—	—	—	(58)	(58)	(60)	—	—
Production	(79)	(41)	(45)	(165)	(114)	(103)	(74)	(89)	(380)	(545)	(50)	(14)
RESERVES AT DEC. 31, 2005³	965	333	533	1,831	1,814	829	579	573	3,795	5,626	1,939	435
Changes attributable to:												
Revisions	(14)	7	7	—	(49)	72	61	(45)	39	39	60	24
Improved recovery	49	—	3	52	13	1	6	11	31	83	—	—
Extensions and discoveries	—	25	8	33	30	6	2	36	74	107	—	—
Purchases ¹	2	2	—	4	15	—	—	2	17	21	—	119
Sales ²	—	—	—	—	—	—	—	(15)	(15)	(15)	—	—
Production	(76)	(42)	(51)	(169)	(125)	(123)	(72)	(78)	(398)	(567)	(49)	(16)
RESERVES AT DEC. 31, 2006^{3,4}	926	325	500	1,751	1,698	785	576	484	3,543	5,294	1,950	562
DEVELOPED RESERVES⁵												
At Jan. 1, 2004	832	304	515	1,651	1,059	641	588	522	2,810	4,461	1,304	140
At Dec. 31, 2004	832	192	386	1,410	990	543	490	469	2,492	3,902	1,510	188
At Dec. 31, 2005	809	177	474	1,460	945	534	439	416	2,334	3,794	1,611	196
At Dec. 31, 2006	749	163	443	1,355	893	530	426	349	2,198	3,553	1,003	311

¹ Includes reserves acquired through property exchanges.² Includes reserves disposed of through property exchanges.³ Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page 24 for the definition of a PSC). PSC-related reserve quantities are 30 percent, 29 percent and 28 percent for consolidated companies for 2006, 2005 and 2004, respectively, and 100 percent for TCO for each year.⁴ Net reserve changes (excluding production) in 2006 consist of 326 million barrels of developed reserves and (91) million barrels of undeveloped reserves for consolidated companies and (428) million barrels of developed reserves and 631 million barrels of undeveloped reserves for affiliated companies.⁵ During 2006, the percentages of undeveloped reserves at December 31, 2005, transferred to developed reserves were 11 percent and 2 percent for consolidated companies and affiliated companies, respectively.

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

In addition to conventional liquids and natural gas proved reserves, Chevron has significant interests in proved oil sands reserves in Canada associated with the Athabasca project. For internal management purposes, Chevron views these reserves and their development as an integral part of total upstream operations. However, SEC regulations define these reserves as mining-related and not a part of conventional oil and gas reserves. Net proved oil sands reserves were 443 million barrels as of December 31, 2006. 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 99.

Noteworthy amounts in the categories of proved-reserve changes for 2004 through 2006 in the table above are discussed below:

Revisions In 2004, net revisions decreased reserves 218 million barrels for consolidated companies and increased reserves for affiliates by 204 million barrels. For consolidated companies, the decrease was composed of 161 million barrels for international areas and 57 million barrels for the United States. The largest downward revision internationally was 70 million barrels in Africa. One field in Angola accounted

for the majority of the net decline as changes were made to oil-in-place estimates based on reservoir performance data. One field in the Asia-Pacific area essentially accounted for the 43 million-barrel downward revision for that region. The revision was associated with reduced well performance. Part of the 36 million-barrel net downward revision for Indonesia was associated with the effect of higher year-end prices on the calculation of reserves for cost-oil recovery under a production-sharing contract. In the United States, the 68 million-barrel net downward revision in the Gulf of

TABLE V - RESERVE QUANTITY INFORMATION - Continued

Mexico area was across several fields and based mainly on reservoir analyses and assessments of well performance. For affiliated companies, the 206 million-barrel increase for TCO was based on an updated assessment of reservoir performance for the Tengiz Field. Partially offsetting this increase was a downward effect of higher year-end prices on the variable royalty-rate calculation. Downward revisions also occurred in other geographic areas because of the effect of higher year-end prices on various production-sharing terms and variable royalty calculations.

In 2005, net revisions reduced reserves by 239 million and 24 million barrels for worldwide consolidated companies and equity affiliates, respectively. For consolidated companies, the net decrease was 199 million barrels in the international areas and 40 million barrels in the United States. The largest downward net revisions internationally were 108 million barrels in Indonesia and 53 million barrels in Kazakhstan, due primarily to the effect of higher year-end prices on the calculation of reserves associated with production-sharing and variable-royalty contracts. In the United States, the 40 million-barrel reduction was across many fields in each of the geographic sections. Most of the downward revision for affiliated companies was a 19 million-barrel reduction in Hamaca, attributable to revised government royalty provisions. For TCO, the downward effect of higher year-end prices was partially offset by increased reservoir performance.

In 2006, net revisions increased reserves by 39 million and 84 million barrels for worldwide consolidated companies and equity affiliates, respectively. International consolidated companies accounted for the net increase of 39 million barrels. The largest upward net revisions were 61 million barrels in Indonesia and 27 million barrels in Thailand. In Indonesia, the increase was the result of infill drilling and improved steamflood performance. The upward revision in Thailand reflected additional drilling and development activity during the year. These upward revisions were partially offset by reductions in reservoir performance in Nigeria and the United Kingdom, which decreased reserves by 43 million barrels and by 32 million barrels, respectively. Most of the upward revision for affiliated companies was related to a 60 million barrel increase in TCO as a result of improved reservoir performance.

Improved Recovery In 2006, improved recovery increased liquids volumes worldwide by 83 million barrels for consolidated companies. Reserves in the United States increased 52 million barrels, with California representing 49 million barrels of the total increase due to steamflood expansion and revised modeling activities. Internationally, improved recovery increased reserves by 31 million barrels, with no single country accounting for an increase of more than 10 million barrels.

Extensions and Discoveries In 2006, extensions and discoveries increased liquids volumes worldwide by 107 million barrels for consolidated companies. Reserves in Nigeria

increased by 27 million barrels due in part to the initial booking of reserves for the Aparo Field. Additional drilling activities contributed 19 million barrels in the United Kingdom and 14 million barrels in Argentina. In the United States, the Gulf of Mexico added 25 million barrels, mainly the result of the initial booking of the Great White Field in the deepwater Perdido Fold Belt area.

Purchases In 2005, the acquisition of 572 million barrels of liquids related solely to the acquisition of Unocal in August. About three-fourths of the 376 million barrels acquired in the international areas were represented by volumes in Azerbaijan and Thailand. Most volumes acquired in the United States were in Texas and Alaska.

In 2006, acquisitions increased liquids volumes worldwide by 21 million barrels for consolidated companies and 119 million barrels for equity affiliates. For consolidated companies, the amount was mainly the result of new agreements in Nigeria, which added 13 million barrels of reserves. The other-equity-affiliates quantity reflects the result of the conversion of Boscan and LL-652 operations to joint stock companies in Venezuela.

Sales In 2004, sales of liquids volumes reduced reserves of consolidated companies by 179 million barrels. Sales totaled 130 million barrels in the United States and 33 million barrels in the "Other" international region. Sales in the "Other" region of the United States totaled 103 million barrels, with two fields accounting for approximately one-half of the volume. The 27 million barrels sold in the Gulf of Mexico reflect the sale of a number of Shelf properties. The "Other" international sales include the disposal of western Canada properties and several fields in the United Kingdom. All the sales were associated with the company's program to dispose of assets deemed nonstrategic to the portfolio of producing properties.

In 2005, sales of 58 million barrels in the "Other" international area related to the disposition of the former Unocal operations onshore in Canada.

In 2006, sales decreased reserves by 15 million barrels due to the conversion of the LL-652 risked service agreement to a joint stock company in Venezuela.

TABLE V - RESERVE QUANTITY INFORMATION - Continued

NET PROVED RESERVES OF NATURAL GAS

<i>Billions of cubic feet</i>	Consolidated Companies											
	United States				International						Affiliated Companies	
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
RESERVES AT JAN. 1, 2004	323	1,841	3,189	5,353	2,642	5,373	520	3,665	12,200	17,553	2,526	112
Changes attributable to:												
Revisions	27	(391)	(316)	(680)	346	236	21	325	928	248	963	23
Improved recovery	2	—	1	3	7	—	13	—	20	23	—	—
Extensions and discoveries	1	54	89	144	16	39	2	13	70	214	—	—
Purchases ¹	—	5	—	5	—	4	—	—	4	9	—	—
Sales ²	—	(147)	(289)	(436)	—	—	—	(111)	(111)	(547)	—	—
Production	(39)	(298)	(348)	(685)	(32)	(247)	(54)	(354)	(687)	(1,372)	(76)	(1)
RESERVES AT DEC. 31, 2004³	314	1,064	2,326	3,704	2,979	5,405	502	3,538	12,424	16,128	3,413	134
Changes attributable to:												
Revisions	21	(15)	(15)	(9)	211	(428)	(31)	243	(5)	(14)	(547)	49
Improved recovery	8	—	—	8	13	—	—	31	44	52	—	—
Extensions and discoveries	—	68	99	167	25	118	5	55	203	370	—	—
Purchases ¹	—	269	899	1,168	5	3,962	247	274	4,488	5,656	—	—
Sales ²	—	—	(6)	(6)	—	—	—	(248)	(248)	(254)	—	—
Production	(39)	(215)	(350)	(604)	(42)	(434)	(77)	(315)	(868)	(1,472)	(79)	(2)
RESERVES AT DEC. 31, 2005³	304	1,171	2,953	4,428	3,191	8,623	646	3,578	16,038	20,466	2,787	181
Changes attributable to:												
Revisions	32	40	(102)	(30)	34	400	38	39	511	481	26	—
Improved recovery	5	—	—	5	3	—	—	5	8	13	—	—
Extensions and discoveries	—	111	157	268	11	510	—	10	531	799	—	—
Purchases ¹	6	13	—	19	—	16	—	—	16	35	—	54
Sales ²	—	—	(1)	(1)	—	—	—	(148)	(148)	(149)	—	—
Production	(37)	(241)	(383)	(661)	(33)	(629)	(110)	(302)	(1,074)	(1,735)	(70)	(4)
RESERVES AT DEC. 31, 2006^{3,4}	310	1,094	2,624	4,028	3,206	8,920	574	3,182	15,882	19,910	2,743	231
DEVELOPED RESERVES⁵												
At Jan. 1, 2004	265	1,572	2,964	4,801	954	3,627	223	3,043	7,847	12,648	1,789	52
At Dec. 31, 2004	252	937	2,191	3,380	1,108	3,701	271	2,273	7,353	10,733	2,584	63
At Dec. 31, 2005	251	977	2,794	4,022	1,346	4,819	449	2,453	9,067	13,089	2,314	85
At Dec. 31, 2006	250	873	2,434	3,557	1,306	4,751	377	1,912	8,346	11,903	1,412	144

¹ Includes reserves acquired through property exchanges.² Includes reserves disposed of through property exchanges.³ Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page 24 for the definition of a PSC). PSC-related reserve quantities are 47 percent, 44 percent and 33 percent for consolidated companies for 2006, 2005 and 2004, respectively, and 100 percent for TCO for each year.⁴ Net reserve changes (excluding production) in 2006 consist of 549 billion cubic feet of developed reserves and 630 billion cubic feet of undeveloped reserves for consolidated companies and (769) billion cubic feet of developed reserves and 849 billion cubic feet of undeveloped reserves for affiliated companies.⁵ During 2005, the percentages of undeveloped reserves at December 31, 2004, transferred to developed reserves were 5 percent and 2 percent for consolidated companies and affiliated companies, respectively.

Noteworthy amounts in the categories of proved-reserve changes for 2004 through 2006 in the table above are discussed below:

Revisions In 2004, revisions increased reserves for consolidated companies by a net 248 billion cubic feet (BCF), composed of increases of 928 BCF internationally and decreases of 680 BCF in the United States. Internationally, about half of the 346 BCF increase in Africa related to properties in Nigeria, for which changes were associated with well performance reviews, development drilling and lease fuel calculations. The 236 BCF addition in the Asia-Pacific region was related primarily to reservoir analysis for a single field. Most of the 325 BCF in the “Other” international area was

related to a new gas sales contract in Trinidad and Tobago. In the United States, the net 391 BCF downward revision in the Gulf of Mexico was related to well-performance reviews and technical analyses in several fields. Most of the net 316 BCF negative revision in the “Other” U.S. area related to two coal bed methane fields in the Mid-Continent region and their associated wells’ performance. The 963 BCF increase for TCO was connected with updated analyses of reservoir performance and processing plant yields.

In 2005, reserves were revised downward by 14 BCF for consolidated companies and 498 BCF for equity affiliates. For consolidated companies, negative revisions were 428 BCF in the Asia-Pacific region. Most of the decrease was attribut-

TABLE V - RESERVE QUANTITY INFORMATION - Continued

able to one field in Kazakhstan, due mainly to the effects of higher year-end prices on variable-royalty provisions of the production-sharing contract. Reserves additions for consolidated companies totaled 211 BCF and 243 BCF in Africa and “Other,” respectively. The majority of the African region changes were in Angola, due to a revised forecast of fuel gas usage, and in Nigeria, from improved reservoir performance. The availability of third-party compression in Colombia accounted for most of the increase in the “Other” region. Revisions in the United States decreased reserves by 9 BCF, as nominal increases in the San Joaquin Valley were more than offset by decreases in the Gulf of Mexico and “Other” region. For the TCO affiliate in Kazakhstan, a reduction of 547 BCF reflects the updated forecast of future royalties payable and year-end price effects, partially offset by volumes added as a result of an updated assessment of reservoir performance.

In 2006, revisions accounted for a net increase of 481 BCF for consolidated companies and 26 BCF for affiliates. For consolidated companies, net increases of 511 BCF internationally were partially offset by a 30 BCF downward revision in the United States. Drilling and development activities added 337 BCF of reserves in Thailand, while Kazakhstan added 200 BCF, largely due to development activity. Trinidad and Tobago increased 185 BCF, attributable to improved reservoir performance and a new contract for sales of natural gas. These additions were partially offset by downward revisions of 224 BCF in the United Kingdom and 130 BCF in Australia due to drilling results and reservoir performance. U.S. “Other” had a downward revision of 102 BCF due to reservoir performance, which was partially offset by upward revisions of 72 BCF in the Gulf of Mexico and California related to reservoir performance and development drilling. TCO had an upward revision of 26 BCF associated with additional development activity and updated reservoir performance.

Extensions and Discoveries In 2004, extensions and discoveries accounted for an increase of 214 BCF, reflecting an increase in the United States of 144 BCF, with 89 BCF added in the “Other” region and 54 BCF added in the Gulf of Mexico through drilling activities in a large number of fields.

In 2005, consolidated companies increased reserves by 370 BCF, including 167 BCF in the United States and 118 BCF in the Asia-Pacific region. In the United States, 99 BCF was added in the “Other” region and 68 BCF in the Gulf of Mexico, primarily due to drilling activities. The addition in Asia-Pacific resulted primarily from increased drilling in Kazakhstan.

In 2006, extensions and discoveries accounted for an increase of 799 BCF for consolidated companies, reflecting a 531 BCF increase outside the United States and a U.S. increase of 268 BCF. Bangladesh added 451 BCF, the result of development activity and field extensions, and Thailand added 59 BCF, the result of drilling activities. U.S. “Other” contributed

157 BCF, approximately half of which was related to the South Texas and the Piceance Basin, and the Gulf of Mexico added 111 BCF, partly due to the initial booking of reserves at the Great White Field in the deepwater Perdido Fold Belt area.

Purchases In 2005, all except 7 BCF of the 5,656 BCF total purchases were associated with the Unocal acquisition. International reserve acquisitions were 4,488 BCF, with Thailand accounting for about half the volumes. Other significant volumes were added in Bangladesh and Myanmar.

In 2006, acquisition of natural gas reserves were 35 BCF for consolidated companies, about evenly divided between the company’s United States and international operations. Affiliated companies added 54 BCF of reserves, the result of conversion of an operating service agreement to a joint stock company in Venezuela.

Sales In 2004, sales for consolidated companies totaled 547 BCF. Of this total, 436 BCF was in the United States and 111 BCF in the “Other” international region. In the United States, “Other” region sales accounted for 289 BCF, reflecting the disposal of a large number of smaller properties, including a coal bed methane field. Gulf of Mexico sales of 147 BCF reflected the sale of Shelf properties, with four fields accounting for more than one-third of the total sales. Sales in the “Other” international region reflected the disposition of the properties in western Canada and the United Kingdom.

In 2005, sales of 248 BCF in the “Other” international region related to the disposition of former-Unocal’s onshore properties in Canada.

In 2006, sales for consolidated companies totaled 149 BCF, mostly associated with the conversion of a risked service agreement to a joint stock company in Venezuela.

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 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 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. In the following table, "Standardized Measure Net Cash Flows" refers to the standardized measure of discounted future net cash flows.

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

<i>Millions of dollars</i>	Consolidated Companies											
	United States				International						Affiliated Companies	
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
AT DECEMBER 31, 2006												
Future cash inflows												
from production	\$ 48,828	\$ 23,768	\$ 38,727	\$ 111,323	\$ 97,571	\$ 70,288	\$ 30,538	\$ 36,272	\$ 234,669	\$ 345,992	\$ 104,069	\$ 20,644
Future production costs	(14,791)	(6,750)	(12,845)	(34,386)	(12,523)	(13,398)	(16,281)	(10,777)	(52,979)	(87,365)	(7,796)	(2,348)
Future devel. costs	(3,999)	(2,947)	(1,399)	(8,345)	(9,648)	(6,963)	(2,284)	(3,082)	(21,977)	(30,322)	(7,026)	(1,732)
Future income taxes	(10,171)	(4,764)	(8,290)	(23,225)	(53,214)	(20,633)	(5,448)	(11,164)	(90,459)	(113,684)	(25,212)	(8,282)
Undiscounted future net cash flows	19,867	9,307	16,193	45,367	22,186	29,294	6,525	11,249	69,254	114,621	64,035	8,282
10 percent midyear annual discount for timing of estimated cash flows	(9,779)	(3,256)	(7,210)	(20,245)	(10,065)	(12,457)	(2,426)	(3,608)	(28,556)	(48,801)	(40,597)	(5,185)
STANDARDIZED MEASURE												
NET CASH FLOWS	\$ 10,088	\$ 6,051	\$ 8,983	\$ 25,122	\$ 12,121	\$ 16,837	\$ 4,099	\$ 7,641	\$ 40,698	\$ 65,820	\$ 23,438	\$ 3,097
AT DECEMBER 31, 2005												
Future cash inflows												
from production	\$ 50,771	\$ 29,422	\$ 50,039	\$ 130,232	\$ 101,912	\$ 73,612	\$ 32,538	\$ 44,680	\$ 252,742	\$ 382,974	\$ 97,707	\$ 20,616
Future production costs	(15,719)	(5,758)	(12,767)	(34,244)	(11,366)	(12,459)	(18,260)	(11,908)	(53,993)	(88,237)	(7,399)	(2,101)
Future devel. costs	(2,274)	(2,467)	(873)	(5,614)	(8,197)	(5,840)	(1,730)	(2,439)	(18,206)	(23,820)	(5,996)	(762)
Future income taxes	(11,092)	(7,173)	(12,317)	(30,582)	(50,894)	(21,509)	(5,709)	(13,917)	(92,029)	(122,611)	(23,818)	(6,036)
Undiscounted future net cash flows	21,686	14,024	24,082	59,792	31,455	33,804	6,839	16,416	88,514	148,306	60,494	11,717
10 percent midyear annual discount for timing of estimated cash flows	(10,947)	(4,520)	(10,838)	(26,305)	(14,881)	(14,929)	(2,269)	(5,635)	(37,714)	(64,019)	(37,674)	(7,768)
STANDARDIZED MEASURE												
NET CASH FLOWS	\$ 10,739	\$ 9,504	\$ 13,244	\$ 33,487	\$ 16,574	\$ 18,875	\$ 4,570	\$ 10,781	\$ 50,800	\$ 84,287	\$ 22,820	\$ 3,949
AT DECEMBER 31, 2004												
Future cash inflows												
from production	\$ 32,793	\$ 19,043	\$ 28,676	\$ 80,512	\$ 64,628	\$ 35,960	\$ 25,313	\$ 30,061	\$ 155,962	\$ 236,474	\$ 61,875	\$ 12,769
Future production costs	(11,245)	(3,840)	(7,343)	(22,428)	(10,662)	(8,604)	(12,830)	(7,884)	(39,980)	(62,408)	(7,322)	(3,734)
Future devel. costs	(1,731)	(2,389)	(667)	(4,787)	(6,355)	(2,531)	(717)	(1,593)	(11,196)	(15,983)	(5,366)	(407)
Future income taxes	(6,706)	(4,336)	(6,991)	(18,033)	(29,519)	(9,731)	(5,354)	(9,914)	(54,518)	(72,551)	(13,895)	(2,934)
Undiscounted future net cash flows	13,111	8,478	13,675	35,264	18,092	15,094	6,412	10,670	50,268	85,532	35,292	5,694
10 percent midyear annual discount for timing of estimated cash flows	(6,656)	(2,715)	(6,110)	(15,481)	(9,035)	(6,966)	(2,465)	(3,451)	(21,917)	(37,398)	(22,249)	(3,817)
STANDARDIZED MEASURE												
NET CASH FLOWS	\$ 6,455	\$ 5,763	\$ 7,565	\$ 19,783	\$ 9,057	\$ 8,128	\$ 3,947	\$ 7,219	\$ 28,351	\$ 48,134	\$ 13,043	\$ 1,877

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.”

<i>Millions of dollars</i>	Consolidated Companies			Affiliated Companies		
	2006	2005	2004	2006	2005	2004
PRESENT VALUE AT JANUARY 1	\$ 84,287	\$ 48,134	\$ 50,805	\$ 26,769	\$ 14,920	\$ 13,118
Sales and transfers of oil and gas produced net of production costs	(32,690)	(26,145)	(18,843)	(3,180)	(2,712)	(1,602)
Development costs incurred	8,875	5,504	3,579	721	810	1,104
Purchases of reserves	580	25,307	58	1,767	—	—
Sales of reserves	(306)	(2,006)	(3,734)	—	—	—
Extensions, discoveries and improved recovery less related costs	4,067	7,446	2,678	—	—	—
Revisions of previous quantity estimates	7,277	(13,564)	1,611	(967)	(2,598)	970
Net changes in prices, development and production costs	(24,725)	61,370	6,173	(837)	19,205	266
Accretion of discount	14,218	8,160	8,139	3,673	2,055	1,818
Net change in income tax	4,237	(29,919)	(2,332)	(1,412)	(4,911)	(754)
Net change for the year	(18,467)	36,153	(2,671)	(235)	11,849	1,802
PRESENT VALUE AT DECEMBER 31	\$ 65,820	\$ 84,287	\$ 48,134	\$ 26,534	\$ 26,769	\$ 14,920

BOARD OF DIRECTORS



David J. O'Reilly, 60

Chairman of the Board and Chief Executive Officer since 2000. Previously he was elected a Director and Vice Chairman in 1998, President of Chevron Products Company in 1994 and a Vice President in 1991. He is a Director of the American Petroleum Institute, the Peterson Institute for International Economics and the Eisenhower Fellowships Board of Trustees. He joined Chevron in 1968.

Peter J. Robertson, 60

Vice Chairman of the Board since 2002. In addition to a broad sharing of the CEO's responsibilities, he is directly responsible for Strategic Planning; Policy, Government and Public Affairs; and Human Resources. Previously he was responsible for worldwide upstream and gas operations. He is a Director of the American Petroleum Institute, the U.S.-Saudi Arabian Business Council and the U.S.-Russian Business Council, and is Chairman of the U.S. Energy Association. He joined Chevron in 1973.

Samuel H. Armacost, 67

Lead Director since 2006 and a **Director** since 1982. He is Chairman of the Board of SRI International. Previously he was President, Chief Executive Officer and a Director of BankAmerica Corporation. He also is a Director of Del Monte Foods Company; Callaway Golf Company; Franklin Resources, Inc.; and Exponent, Inc. (3, 4)



Sam Ginn, 69

Director since 1989. He is a private investor and the 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 is a Director of ICO Global Communications (Holdings) Limited and is a Member of the Yosemite Fund Council and the Hoover Institute Board of Overseers. (2, 3)

Franklyn G. Jenifer, 67

Director since 1993. He is President Emeritus 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. (1)

Sam Nunn, 68

Director since 1997. 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. He is a Director of The Coca-Cola Company, Dell Inc. and the General Electric Company. (2, 3)



Linnet F. Deily, 61

Director since 2006. She served as a Deputy U.S. Trade Representative and Ambassador to the World Trade Organization from 2001 to June 2005. Previously she was Vice Chairman of Charles Schwab Corporation. She is a Director of Alcatel-Lucent and Honeywell International Inc. (1)

Robert E. Denham, 61

Director since 2004. He is a Partner in the law firm of Munger, Tolles & Olson LLP. Previously he was Chairman and Chief Executive Officer of Salomon Inc. He also is a Director of Alcatel-Lucent; Wesco Financial Corporation; and Fomento Económico Mexicano, S.A. de C.V. (1)

Robert J. Eaton, 67

Director since 2000. 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. (2, 4)



Donald B. Rice, 67

Director since 2005. He is Chairman of the Board, President and Chief Executive Officer of Agensys, Inc., a private biotechnology company. Previously he was President and Chief Operating Officer of Teledyne, Inc. He is a Director of Amgen, Inc.; Vulcan Materials Company; and Wells Fargo & Company. (2, 3)

Charles R. Shoemate, 67

Director since 1998. He is retired Chairman of the Board, President and Chief Executive Officer of Bestfoods. (1)

Ronald D. Sugar, 58

Director since 2005. He is Chairman of the Board, Chief Executive Officer and President of Northrop Grumman Corporation. Previously he was President and Chief Operating Officer of Northrop Grumman. He is a Governor of the Aerospace Industries Association and a Member of the National Academy of Engineering. (2, 4)

Carl Ware, 63

Director since 2001. He was Senior Adviser to the Chief Executive Officer of The Coca-Cola Company from 2003 until 2006 after retiring as 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 Coca-Cola Bottling Co. Consolidated and Cummins Inc. (3, 4)

COMMITTEES OF THE BOARD

- 1) Audit: Charles R. Shoemate, Chair
- 2) Public Policy: Sam Nunn, Chair
- 3) Board Nominating and Governance: Samuel H. Armacost, Chair
- 4) Management Compensation: Robert J. Eaton, Chair

CORPORATE OFFICERS



Lydia I. Beebe, 54

Corporate Secretary since 1995. Responsible for providing corporate governance counsel to the Board of Directors and senior management, and managing stockholder relations and subsidiary governance. Previously Senior Manager, Chevron Tax Department; Manager, Federal Tax Legislation; and Chevron Legal Representative in Washington, D.C. Joined Chevron in 1977.

John E. Bethancourt, 55

Executive Vice President, Technology and Services, since 2003. Responsible also for health, environment and safety as well as project resources, procurement, additives and coal operations. Previously the company's Vice President, Human Resources, and Texaco Corporate Vice President and President, Production Operations, Texaco Worldwide Exploration and Production. Joined the company in 1974.

Stephen J. Crowe, 59

Vice President and Chief Financial Officer since 2005. Responsible for comptroller, audit, treasury, tax and investor relations activities corporatewide. Previously Chevron Vice President and Comptroller; Vice President, Finance, Chevron Products Company; and Assistant Comptroller, Chevron Corporation. Joined Chevron in 1972.

John D. Gass, 54

Corporate Vice President and President, Chevron Global Gas, since 2003. Responsible for the company's natural gas business, shipping company, power and pipeline operations, and the Sasol Chevron gas-to-liquids joint venture. Director of Sasol Chevron and GS Caltex Corporation. Previously Managing Director, Southern Africa Strategic Business Unit, and Managing Director, Chevron Australia Pty Ltd. Joined the company in 1974.

Mark A. Humphrey, 55

Vice President and Comptroller since 2005. Responsible for corporatewide accounting, financial reporting and analysis, internal controls, funded benefits investments, actuarial functions, and Finance Shared Services. Previously the company's General Manager, Finance Shared Services, and Vice President, Finance, Chevron Products Company. Joined Chevron in 1976.

Charles A. James, 52

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, and Chair, Antitrust and Trade Regulation Practice - Jones, Day, Reavis & Pogue, Washington, D.C. Joined Chevron in 2002.

George L. Kirkland, 56

Executive Vice President, Upstream and Gas, since 2005. Responsible for global exploration, production and gas activities. Previously Corporate Vice President and President, Chevron Overseas Petroleum Inc.; President, Chevron Exploration and Production Company; and President, Chevron U.S.A. Production Company. Joined Chevron in 1974.

David M. Krattetol, 62

Vice President and Treasurer since 2000. Previously 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 Chevron in 1971.

Gary P. Luquette, 51

Corporate Vice President and President, Chevron North America Exploration and Production Company, since 2006. Previously Managing Director, Upstream Europe Strategic Business Unit, Chevron International Exploration and Production Company, and Vice President, San Joaquin Valley Business Unit, Chevron North America Exploration and Production Company. Joined Chevron in 1978.



John W. McDonald, 55

Vice President, Strategic Planning, since 2002. Responsible for advising senior management in setting the company's strategic direction, mergers and acquisitions. Previously President and Managing Director, Chevron Upstream Europe, Chevron Overseas Petroleum Inc., and Vice President, Gulf of Mexico Offshore Division, Texaco Exploration and Production Inc. Joined the company in 1975.

Donald L. Paul, 60

Vice President and Chief Technology Officer since 2001. Responsible for Chevron's three technology companies: Energy Technology, Information Technology and Technology Ventures. Previously Chevron Vice President, Technology and Environmental Affairs; President, Chevron Canada Resources; and President, Chevron Petroleum Technology Company. Joined Chevron in 1975.

Alan R. Preston, 55

Vice President, Human Resources, since 2003. Previously the company's General Manager, Global Remuneration; General Manager, Organization/Compensation, Chevron Corporation; and General Manager, Human Resources, Chevron Products Company. Joined Chevron in 1973.

Jay R. Pryor, 49

Vice President, Business Development, since May 2006. Responsible for identifying and developing new, large-scale business opportunities worldwide. Previously Managing Director, Nigeria/Mid-Africa Strategic Business Unit and Chevron Nigeria Ltd., and Managing Director, Asia South Business Unit and Chevron Offshore (Thailand) Ltd. Joined Chevron in 1979.

Thomas R. Schuttish, 59

General Tax Counsel since 2002. Responsible for guiding and directing corporatewide tax activities and managing Chevron's Tax department. Previously the company's Assistant General Tax Counsel. Joined Chevron in 1980.

John S. Watson, 50

Corporate Vice President and President, Chevron International Exploration and Production Company, since 2005. Responsible for exploration and production activities outside North America. Previously Chevron Vice President and Chief Financial Officer; Chevron Vice President, Strategic Planning; and Director, Caltex Petroleum Corporation. Joined Chevron in 1980.

Michael K. Wirth, 46

Executive Vice President, Downstream, since 2006. Responsible for worldwide refining, marketing, lubricants, and supply and trading. Previously President, Global Supply and Trading; President, Marketing, Asia/Middle East/Africa Strategic Business Unit; and President, Marketing, Caltex Corporation. Joined Chevron in 1982.

Patricia E. Yarrington, 50

Vice President, Policy, Government and Public Affairs, since 2002. Responsible for government relations, community relations and communications. Director of Chevron Phillips Chemical Company LLC. Previously Chevron Vice President, Strategic Planning; President, Chevron Canada Limited; and Comptroller, Chevron Products Company. Joined Chevron in 1980.

Rhonda I. Zygozki, 49

Vice President, Health, Environment and Safety, since 2003. Responsible for HES strategic planning and issues management, compliance and auditing, and emergency response. Previously Managing Director, Chevron Australia Pty Ltd; Adviser to the Chairman of the Board, Chevron Corporation; and Manager of Strategic Planning, Chevron Corporation. Joined Chevron in 1980.

EXECUTIVE COMMITTEE

David J. O'Reilly, Peter J. Robertson, John E. Bethancourt, Stephen J. Crowe, Charles A. James, George L. Kirkland and Michael K. Wirth. Lydia I. Beebe, Secretary.

Chevron History

- | | | | |
|-------------|--|-------------|---|
| 1879 | Incorporated in San Francisco, California, as the Pacific Coast Oil Company. | 1984 | Acquired Gulf Corporation – nearly doubling the size of crude oil and natural gas activities – and gained significant presence in industrial chemicals, natural gas liquids and coal. Changed name to Chevron Corporation to identify with the name under which most products were marketed. |
| 1900 | Acquired by the West Coast operations of John D. Rockefeller's original Standard Oil Company. | 1988 | Purchased Tenneco Inc.'s U.S. Gulf of Mexico crude oil and natural gas properties, becoming one of the largest U.S. natural gas producers. |
| 1911 | Emerged as an autonomous entity – Standard Oil Company (California) – following the U.S. Supreme Court decision to divide the Standard Oil conglomerate into 34 independent companies. | 1993 | Formed Tengizchevroil, a joint venture with the Republic of Kazakhstan, to develop and produce the giant Tengiz Field, becoming the first major Western oil company to enter newly independent Kazakhstan. |
| 1926 | Acquired Pacific Oil Company to become Standard Oil Company of California (Socal). | 1999 | Acquired Rutherford-Moran Oil Corporation and Petrolera Argentina San Jorge S.A. These acquisitions provided inroads to Asian natural gas markets and built on the company's Latin America business foundation. |
| 1936 | Formed the Caltex Group of Companies, jointly owned by Socal and The Texas Company (later became Texaco), to manage exploration and production interests of the two companies in the Middle East and Indonesia and provide an outlet for crude oil through The Texas Company's European markets. | 2001 | Merged with Texaco Inc. and changed name to ChevronTexaco Corporation. Became the second-largest U.S.-based energy company. |
| 1947 | Acquired Signal Oil Company, obtaining the Signal brand name and adding 2,000 retail stations in the western United States. | 2002 | Relocated corporate headquarters from San Francisco, California, to San Ramon, California. |
| 1961 | Acquired Standard Oil Company (Kentucky), a major petroleum products marketer in five southeastern states, to provide outlets for crude oil from southern Louisiana and the U.S. Gulf of Mexico, where the company was a major producer. | 2005 | Acquired Unocal Corporation, an independent crude oil and natural gas exploration and production company. Unocal's upstream assets bolstered Chevron's already-strong position in the Asia-Pacific, U.S. Gulf of Mexico and Caspian regions. Changed name to Chevron Corporation to convey a clearer, stronger and more unified presence in the global marketplace. |

STOCKHOLDER AND INVESTOR INFORMATION

Stock Exchange Listing

Chevron common stock is listed on the New York Stock Exchange. The symbol is "CVX."

Stockholder Information

Questions about stock ownership, changes of address, dividend payments or direct deposit of dividends should be directed to Chevron's transfer agent and registrar:

Mellon Investor Services LLC
480 Washington Boulevard
27th Floor
Jersey City, NJ 07130-2098
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*.)

Annual Meeting

The Annual Meeting of stockholders will be held at 8:00 a.m., Wednesday, April 25, 2007, at: Chevron 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 review the materials and to vote their shares. Generally, stockholders may vote by telephone, on the Internet, by mail or by attending the meeting.

Electronic Access

Rather than receiving mailed copies, stockholders of record may sign up on our Web site, www.icsdelivery.com/cvx/index.html, for electronic access to future *Annual Reports* and proxy materials. Enrollment is revocable until each year's Annual Meeting record date. Beneficial stockholders may be able to request electronic access by contacting their broker or bank, or ADP at: www.icsdelivery.com/cvx/index.html.

Investor Information

Securities analysts, portfolio managers and representatives of financial institutions may contact:

Investor Relations
Chevron Corporation
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324
925 842 5690
Email: invest@chevron.com

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.

The *Form 10-K*, prepared annually for the Securities and Exchange Commission, is available after March 1. The *Supplement to the Annual Report*, containing additional financial and operating data, is available after April 15. Both are available on the company's Web site, www.chevron.com, or copies may be requested by writing to: Comptroller's Department
Chevron Corporation
6001 Bollinger Canyon Road, A3201
San Ramon, CA 94583-2324

The *Corporate Responsibility Report* is available in late April on the company's Web site, www.chevron.com, or a copy may be requested by writing to: Policy, Government and Public Affairs
Chevron Corporation
6001 Bollinger Canyon Road, A2181
San Ramon, CA 94583-2324

Details of the company's *political contributions* for 2006 are available on the company's Web site, www.chevron.com, or by writing to: Policy, Government and Public Affairs
Chevron 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 Chevron's Web site, www.chevron.com.

For additional information about the company and the energy industry, visit Chevron's Web site, www.chevron.com. It includes articles, news releases, speeches, quarterly earnings information, the *Proxy Statement* and the complete text of this *Annual Report*.

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 STATEMENT 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.

INDIVIDUALS NOT IDENTIFIED IN TEXT **Page 7:** Saudi Arabian Chevron's Nayef Al-Harbi, a desalter coordinator at Joint Operations, Wafra Field, Partitioned Neutral Zone; **Page 9:** Amoseas Indonesia Production Engineers Fachrul Subarkah (left) and Fernando Pasarihu, Darajat, Indonesia; **Page 12:** Senior Analyst Budi Riyanto, Maintenance Mechanical, North Duri Cogeneration Plant, Indonesia; **Page 14:** (top to bottom) Hathaiporn Samorn, Thailand, and Reginald Onyirioha and Olusola Bakare, Nigeria – Chevron employee participants, CoRE program, Colorado School of Mines, Golden, Colorado, United States.

PHOTOGRAPHY **Front/Back Cover:** Fredrik Broden; **Inside Front Cover/Page 1:** Francesco Lagnese, Riser, Getty Images; **Page 6:** Greg Smith; **Page 7:** Chris Martin; **Page 8:** Eric Myer; **Pages 9, 21 (left):** Peter Cannon; **Pages 10, 14:** Paul S. Howell; **Page 11:** Mark Viker, Stone, Getty Images; **Page 12:** Melbourne the Photographer; **Page 13:** D. Ross Cameron, The Oakland Tribune; **Page 15:** Claire Maneja; **Pages 16, 20:** Jim Karageorge; **Page 19:** José Pinto; **Page 21:** (right) Christian Sprogø; **Page 22:** (left) Jamie Koh, Joe Lynch; **Page 23:** (left) Marilyn Hulbert, Michael Goldwater; **Inside Back Cover:** (top to bottom) Fredrik Broden, Marilyn Hulbert, Pradonggo.

PORTRAITS **Page 2:** Eric Myer; **Pages 6, 8, 11, 13:** Jim Karageorge; **Page 15:** Victor Turco.

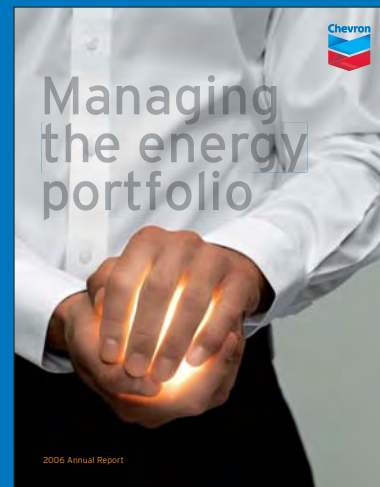
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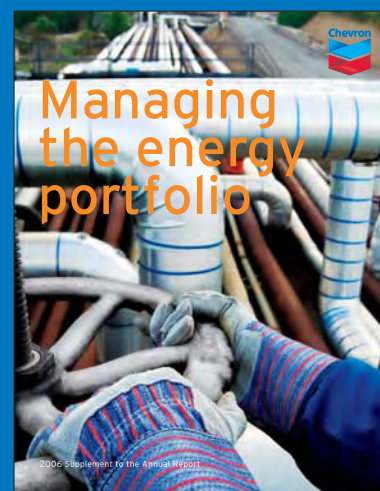
As used in this report, the term “Chevron” and such terms as “the company,” “the corporation,” “our,” “we” and “us” may refer to one or more of its consolidated subsidiaries or to all of them taken as a whole. All of these terms are used for convenience only and are not intended as a precise description of any of the separate companies, each of which manages its own affairs.

Corporate Headquarters

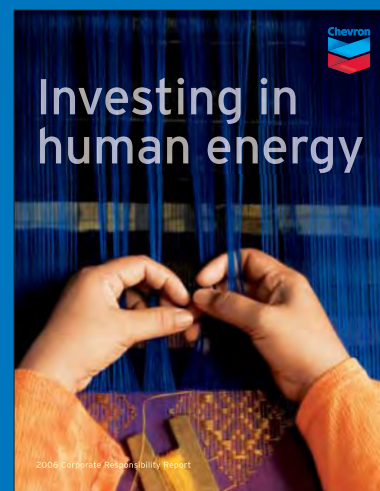
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925 842 1000



2006 Annual Report



2006 Supplement to the Annual Report



2006 Corporate Responsibility Report



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