Defining Devon / *2005 Annual Report* – DEVON ENERGY CORPORATION

How we are defined by *others* is as important as how we define ourselves.

Devon /dev•on/ Devon is the largest U.S.-based *independent* oil and gas exploration and production company. **Dev•on** also owns natural gas pipelines and treatment facilities in many of its producing areas, making **Dev•on** one of North America's larger processors of natural gas liquids. **Dev•on's** operations are *focused* primarily in the United States and Canada; however, the company also *explores* for and *produces* oil and natural gas in selected areas outside North America. **Dev•on** is included in the S&P 500 Index and trades on the New York Stock Exchange under the ticker symbol **DVN**.

respectful /re•spect•ful/ "Devon built its reputation by being honest, and following through on what it says it's going to do. Devon respects landowner interests, and the company always comes in with the equipment and expertise to get the job done right."

Terry Belsheim
Landowner
ALBERTA, CANADA

"The people working for Devon really set it apart from other companies. It's been my experience that everyone I've dealt with—from the landman I first met in 1978 and had coffee with just last week, through to the local operators and contractors employed by Devon—are fair, considerate and take pride in the company's operations. The small gestures really count. Devon's folks phone to let me know if my cattle are out, and once they even helped me round them up.

"Devon built its reputation by being honest, and following through on what it says it's going to do. Devon respects landowner interests, and the company always comes in with the equipment and expertise to get the job done right.

"Between droughts and mad cow disease, farmers have really had some challenges in recent years. Devon's helped us survive through those hard times. As my neighbor once said, there's nothing nicer than the sight of a cow lying in the shade of an oil tank."

proactive /pro•ac•tive/ "Devon consistently demonstrates its commitment to being a proactive community partner in north Texas, and we value the company's support. Without Devon, our community crime watch effort would not be as successful as it is today."

David Walker
Sheriff
WISE COUNTY, TEXAS

"In law enforcement, if you're not thinking ahead, you're not benefiting your citizens to the fullest. It pays to be proactive, and our community partnerships are essential to serve the needs of the county.

"Devon and the Wise County Sheriff's Department have enjoyed a long-standing partnership resulting in an outstanding community crime watch program called 'Wise Eyes.' The program links my office and hundreds of people who travel the county every day. With all of those eyes and ears watching and listening, suspicious activity is more likely to be reported. It's like having a deputy force of more than 400, with Devon employees accounting for a large percentage of those volunteers. 'Wise Eyes' is so successful in Wise County that it has become a model for other sheriffs' departments across Texas and several other states.

"Devon consistently demonstrates its commitment to being a proactive community partner in north Texas, and we value the company's support. Without Devon, our community crime watch effort would not be as successful as it is today."

David Walker / *Sheriff* – WISE COUNTY, TEXAS

honest /hon•est/ “It was hard to believe at first that Devon’s objective was conservation, but their honesty and commitment convinced us that, with this company, there was no need to be skeptical.”

Sonja Macys
Executive Director
TUCSON AUDUBON SOCIETY, ARIZONA

“Whenever an environmental organization is approached by an energy company with a gift of land, there is cause to be skeptical. That was our reaction when Devon Energy proposed to donate several hundred acres to the Tucson Audubon Society in 2003. It sounded too good to be true, but what happened next changed our minds.

“After identifying a piece of Sonoran Desert property along the Santa Cruz River as a potential habitat restoration site, Devon contacted the Audubon Society about a possible partnership. What eventually transpired was a complicated, three-way transaction between our organization, Devon and a land development company. It was an unlikely partnership with diverging objectives and plenty of conflict. There were opportunities for Devon to back out on its idea and sell the land to the highest bidder. But the company kept its promise, and in the end, we established the Esperanza Ranch Habitat Restoration Project.

“It was hard to believe at first that Devon’s objective was conservation, but their honesty and commitment convinced us that, with this company, there was no need to be skeptical.”

Sonja Macys / *Executive Director* – TUCSON AUDUBON SOCIETY, ARIZO

successful /suc•cess•ful/ "With its Polvo discovery in Brazil's prolific Campos Basin, Devon joins a growing group of companies that are achieving exploration success in Brazilian waters. We hope Devon's success with the Polvo project will lead to other exploration projects..."

Newton Monteiro
Director
NATIONAL PETROLEUM AGENCY, BRAZIL

"Brazil has a long and proud heritage of offshore oil and gas exploration, and some of the world's larger deepwater oil fields were discovered in Brazilian waters. As a government agency, one of our tasks is to identify and develop the country's vast resource potential.

As the United States' largest independent exploration and production company, Devon Energy's investments in our country validate Brazil as an attractive place for blue-ribbon oil companies to do business. Particularly impressive to us are Devon's corporate values, its emphasis on positive long-term relationships and its willingness to support local industry as a good corporate citizen.

"With its Polvo discovery in Brazil's prolific Campos Basin, Devon joins a growing group of companies that are achieving exploration success in Brazilian waters. We hope Devon's success with the Polvo project will lead to other exploration projects resulting in economic and social benefits for our people."

Letter to Shareholders

Dear Fellow Shareholders: For Devon Energy Corporation, 2005 was a year defined by accomplishment. Many are readily apparent: oil and gas reserves, revenues, cash flow, earnings and earnings per share all climbed to record levels. However, other significant accomplishments are less obvious.

RECORD DRILLING BUDGET YIELDS SIGNIFICANT GROWTH

At about $4 billion, Devon's 2005 capital budget represented the highest level of exploration and development investment in our history. And the results of this capital program were a resounding success. We added almost 440 million equivalent barrels of proved oil and gas reserves during the year—nearly double the 226 million barrels we produced. Furthermore, we added these reserves almost entirely with the drill bit at very attractive finding and development costs. Devon's 2005 reserves growth resulted from drilling activity across our core North American asset base. Onshore in the United States and Canada, we invested $3.3 billion and drilled about 2,260 successful wells.

The Barnett Shale continues to be our most significant area in the United States for growth in oil and gas reserves. The Barnett is the largest natural gas field in Texas, and Devon is the largest producer in the field. Drilling 217 Barnett wells in 2005, we added 690 billion cubic feet of natural gas equivalent reserves, or more than triple our Barnett production for the year. In addition to growing Barnett reserves dramatically, we also increased our Barnett production. Late in the fourth quarter our daily production reached an all-time high of 580 million cubic feet of gas equivalent per day. Continuing this growth trajectory, we are targeting an exit rate of 630 million cubic feet equivalent per day from the Barnett Shale in 2006.

In Canada, during 2005 we added the first 118 million barrels of reserves at our Jackfish oil sands project—a project we initiated in 2003. We expect to eventually recover a total of 300 million barrels of oil at Jackfish. When fully operational in 2008, we expect this 100% Devon-owned project to produce 35,000 barrels of oil per day, and to do so for more than 25 years, without decline. In addition, we are evaluating the area around Jackfish for the potential to double, or possibly even triple, the size of the project.

The Barnett Shale and Jackfish projects are only two examples of the many projects across North America that currently contribute to Devon's growth. I invite you to explore these projects and numerous others in more detail in the Portfolio of Oil and Gas Properties beginning on page 19.

BUILDING FOR THE LONG RUN

For several years in Devon's annual reports, I have discussed our commitment to achieve sustainable success over the long term. In a world where oil and gas are increasingly scarce commodities, simply developing low-risk opportunities in our existing producing areas is not enough. We believe that in order to ensure sustainable growth over the longer term, we must invest today in projects that can provide an uninterrupted stream of growth opportunities tomorrow. Our actions reflect this resolve. For several years we have been investing hundreds of millions of dollars annually on these longer-term projects. Although these projects do not provide immediate results, this strategy is paying off. While Devon's core North American assets delivered the 2005 reserves growth, perhaps more important were the projects that set the stage for continued growth in the future.

In the deepwater Gulf of Mexico, we drilled delineation wells on both our Cascade and Jack prospects in the lower Tertiary trend. The information gained from these wells boosts our confidence that these exciting discoveries may soon lead to full-scale development. The next step toward a development decision, an extended production test, is now under way at Jack. Flow rates, pressure data and other reservoir measurements will enable Devon and its partners to select a development approach and optimize the design of production facilities.

Assuming the lower Tertiary can be economically developed, it will be a new producing horizon in the deepwater Gulf of Mexico. Devon, with three delineated discoveries in hand and a leading acreage position in the play, is ideally positioned to benefit from this emerging resource.

Also in 2005, we sanctioned the development of Polvo. Devon operates and owns 60% of this 2004 oil discovery in the Campos Basin offshore Brazil. Platform fabrication is currently under way and we expect first production in the second half of 2007. This initial development should establish about 50 million barrels of proved reserves. Furthermore, in 2006 we plan to drill three additional wells in the area in an attempt to expand the project.

In addition to first production at Polvo, 2007 will also bring us a significant increase in oil production from Azerbaijan. Devon's 5.6% carried interest in the ACG field is subject to payout provisions that we should satisfy in the first half of 2007. At that point, Devon's share of ACG production will jump to between 30,000 and 35,000 barrels of oil per day from the current 1,300 barrels per day.

GULF STORMS BRING CHALLENGES AND ACCOMPLISHMENTS

The storms that devastated portions of the U.S. Gulf Coast in 2005 touched Devon in many ways. Dozens of Devon's Gulf area employees lived directly in the path of hurricanes, and a number of employees lost their homes in the storms. In the face of personal hardships, those employees remained incredibly dedicated to ensuring that Devon's personnel and assets were safeguarded. I am both humbled by their dedication and proud of their performance.

I'm also very proud of the response of Devon's employees who were not directly impacted by the storms. Employees throughout the company responded with overwhelming generosity and compassion for their fellow employees.

Our Gulf team also did an excellent job of responding to the storms from an operational standpoint. As a result of the dedicated efforts of Devon's employees, we had no injuries or reported spills throughout this entire ordeal and our suspended volumes were less than 3% of our 2005 production.

SHARPENING THE FOCUS

Devon increased oil and gas reserves during 2005 in spite of divesting properties during the year with reserves of more than 180 million equivalent barrels. These property sales completed a $2 billion divestiture program initiated in late 2004. The properties divested included those with high decline rates, limited growth potential, high operating costs and those that were outside our geographical areas of focus. Selling producing properties obviously reduces current oil and gas reserves and production. However, we believe the short-term impact will be more than offset by the longer-term benefits. We emerge from these divestitures with our efforts focused on an asset base that is more efficient to operate and of higher overall quality.

DELIVERING ON THE PROMISE

Record 2005 earnings and cash flow coupled with the proceeds from the property divestitures provided Devon with unprecedented amounts of free cash. We deployed this capital with a focus on optimizing value per share. In addition to successfully deploying the largest capital budget in our history, we purchased $2.3 billion of our common stock in 2005, reducing outstanding shares by 8%. Also during the year, we repaid $1.3 billion in debt, reducing net debt to just 19% of adjusted capital. The bottom line? During 2005 we increased the proved oil and gas reserves behind each Devon share by 11% while reducing overall indebtedness.

DEFINING OUR FUTURE

With our 2006 capital budget we expect to again add more than 400 million equivalent barrels of oil and gas reserves, entirely through drilling. And despite upward cost pressure and intense competition for equipment and personnel, we expect to again deliver very competitive finding and development costs in 2006.

As I look ahead in 2006 and beyond, the opportunity for Devon has never been more clearly defined. We have a high-quality base of core properties delivering a steady stream of oil and gas reserves and production. We have the visibility of significant production growth from large-scale development projects already in hand, including the Barnett Shale, Jackfish, Polvo and ACG. Furthermore, we have a large, high-quality inventory of exploration opportunities and a skilled and dedicated workforce to fuel Devon's growth into the next decade.

In this 2005 Annual Report, we explore how Devon is defined by many of those whose lives have been touched by the company. You will hear from representatives of the investment community, regulatory agencies, our employees, our business partners and members of the communities where Devon's employees live and work. I am extremely proud of the values embodied by Devon and its employees and to hear these values reflected in the words of others.

I know of no one that has better exemplified the values that Devon holds dear than long-time director, Michael Gellert. Our friend recently retired after serving 35 years on Devon's board. Mike's contributions to the company's success are immeasurable and deeply appreciated.

J Larry Nichols

J. Larry Nichols
Chairman and Chief Executive Officer
MARCH 10, 2006

YEAR ENDED DECEMBER 31,		2001	2002	2003	2004	2005	LAST YEAR CHANGE
Financial Data [1] *(Millions, except per share data)*							
Total revenues	$	2,864	4,316	7,352	9,189	10,741	17%
Total expenses and other income, net		2,836	4,450	5,107	5,896	6,189	5%
Earnings (loss) before income taxes		28	(134)	2,245	3,293	4,552	38%
Total income tax expense (benefit)		5	(193)	514	1,107	1,622	47%
Net earnings from continuing operations		23	59	1,731	2,186	2,930	34%
Net results of discontinued operations		31	45	—	—	—	N/M
Cumulative effect of change in accounting principle		49	—	16	—	—	N/M
Net earnings		103	104	1,747	2,186	2,930	34%
Preferred stock dividends		10	10	10	10	10	—
Net earnings applicable to common stockholders	$	93	94	1,737	2,176	2,920	34%
Net earnings per share:							
Basic	$	0.37	0.31	4.16	4.51	6.38	41%
Diluted	$	0.36	0.30	4.04	4.38	6.26	43%
Weighted average common shares outstanding:							
Basic		255	309	417	482	458	-5%
Diluted		259	313	433	499	470	-6%
Cash flow from continuing operating activities	$	1,776	1,726	3,768	4,816	5,612	17%
Operating cash flows from discontinued operations		134	28	—	—	—	N/M
Net cash provided by operating activities	$	1,910	1,754	3,768	4,816	5,612	17%
Cash dividends per common share	$	0.10	0.10	0.10	0.20	0.30	50%

DECEMBER 31,		2001	2002	2003	2004	2005	LAST YEAR CHANGE
Total assets	$	13,184	16,225	27,162	30,025	30,273	1%
Debentures exchangeable into shares of Chevron Corporation common stock [2]	$	649	662	677	692	709	2%
Other long-term debt	$	5,940	6,900	7,903	6,339	5,248	-17%
Stockholders' equity	$	3,259	4,653	11,056	13,674	14,862	9%
Working capital	$	435	22	293	772	1,272	65%
Property Data [1]							
Proved reserves *(Net of royalties)*							
Oil *(MMBbls)*		527	444	661	596	649	9%
Gas *(Bcf)*		5,024	5,836	7,316	7,494	7,296	-3%
NGLs *(MMBbls)*		108	192	209	232	246	6%
Oil, Gas and NGLs *(MMBoe)* [3]		1,472	1,609	2,089	2,077	2,112	2%

YEAR ENDED DECEMBER 31,	2001	2002	2003	2004	2005	LAST YEAR CHANGE
Production *(Net of royalties)* [4]						
Oil *(MMBbls)*	36	42	62	78	64	-18%
Gas *(Bcf)*	489	761	863	891	827	-7%
NGLs *(MMBbls)*	8	19	22	24	24	-1%
Oil, Gas and NGLs *(MMBoe)* [3]	126	188	228	251	226	-10%

(1) Years 2001 through 2002 exclude results from Devon's operations in Indonesia, Argentina and Egypt that were discontinued in 2002. Devon acquired new assets in Egypt and Indonesia in the April 2003 Ocean merger that are included in Devon's continuing operations since 2003. Revenues, expenses and production in 2003 include only eight and one-fourth months attributable to the Ocean merger; in 2002, include only 11 and one-fourth months attributable to the Mitchell merger and in 2001, include only two and one-half months attributable to the Anderson acquisition. All periods have been adjusted to reflect the two-for-one stock split that occurred on November 15, 2004.
(2) Debentures exchangeable into 14.2 million shares of Chevron Corporation common stock beneficially owned by Devon.
(3) Gas converted to oil at the ratio of 6Mcf:1Bbl. Natural gas liquids converted to oil at the ratio of 1Bbl:1Bbl.
(4) Declining production in 2005 versus 2004 was largely attributed to property divestitures completed in the first half of 2005.
N/M Not a meaningful number.

insightful /in•sight•ful/ "I bought my first shares of Devon stock in 1991 and have been adding to my position ever since. Devon is an insightful company that has executed a long-term strategy, often in the face of doubters, and has emerged with brilliant results."

Murray Wright
Investor
RICHMOND, VIRGINIA

"I became an investor in 1968, using money from a part-time job at my father's business. After graduating from law school, I continued to invest through the economically challenging 1970s and emerged not much richer, but a lot wiser.

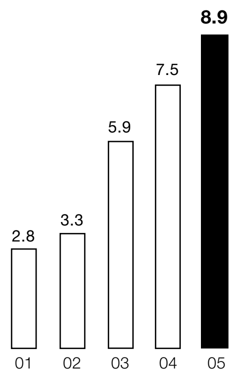
"Through those early years I identified a set of principles that continue to be my guide, such as do your homework, and only invest in companies whose business models you truly understand. I also look for companies with capable and honest management. I bought my first shares of Devon stock in 1991 and have been adding to my position ever since. Devon is an insightful company that has executed a long-term strategy, often in the face of doubters, and has emerged with brilliant results. The company also has a keen sense of community, operating with honesty and integrity to benefit all of its constituencies.

"Devon is a shareholder friendly company, with leaders that are grounded and directed by solid ethical principles. The company's core values instill confidence from the community."

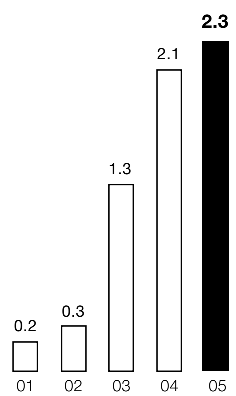
Murray Wright / *Investor* – RICHMOND, VIRGINIA

Q&A

OIL, GAS AND NGL REVENUES
($ Billions)



CASH, CASH EQUIVALENTS AND SHORT-TERM INVESTMENTS
($ Billions)



Higher product prices led to 19% growth in oil and gas sales in 2005, funding all the company's capital demands while increasing cash on hand.

Oil and natural gas prices increased significantly in 2005. Why did the company not hedge some of its 2006 production to lock in higher prices?

Devon has followed a consistent hedging approach. We know that we cannot reliably predict the short-term course of oil and natural gas prices, and therefore we do not speculate on oil and gas prices with hedges. However, we believe hedges can be a useful tool to mitigate a specific risk. An example from Devon's history occurred in early 2002. As a result of the acquisitions of Anderson Exploration and Mitchell Energy, we carried significant debt on our balance sheet. To ensure sufficient levels of cash flow to meet our debt repayment obligations and fund our capital budget, we used hedges to protect floor prices on portions of our oil and gas production.

Today, after several very profitable years, we have repaid a significant amount of debt. Therefore, with Devon's strong balance sheet, we have no compelling reason to hedge. Going into 2006 we had no oil or gas hedges in place.

Devon pledged $2 million to hurricane relief in 2005. What is Devon's strategy for corporate giving?

Community involvement is a core value at Devon, and the company is committed to giving back to the communities where we have a business presence. The trail of destruction from Hurricanes Katrina and Rita left a lasting impression. Due to the size and impact of the storms, Devon has pledged to help rebuild communities that were affected. Devon's $2 million donation is providing both short-term and long-term assistance to communities in Louisiana and Texas where Devon employees live and the company operates.

Youth, education and emergency response organizations such as volunteer fire and sheriffs' departments are focus areas in our corporate giving program. We support programs and organizations that have a direct impact on young lives while enhancing the social and economic development of communities. From our tutoring program at an Oklahoma City elementary school to building schools in Lagos, Nigeria, Devon and its employees worldwide take great pride in giving back to the community. Our employees embrace our community initiatives and play an active role in our volunteer efforts.

What is Devon doing to counteract the rise in oil field costs?

The current tightness in oil and natural gas supplies and the resulting uplift in oil and gas prices have led to an accelerated search for new reserves around the world. This increase in activity has led to soaring demand for oil field equipment, supplies and services. Daily drilling rig rates, for example, have increased dramatically, as has the price of steel pipe and the diesel fuel used to power the rigs. Experienced crews are in short supply, driving up the salaries of the personnel who man the rigs.

As a large customer of the service companies, however, we have some leverage to control costs. We concentrate our business by forming strategic alliances with select suppliers. This results in volume pricing for Devon and specified levels of performance by the vendors. We also work together with the vendors to find mutually beneficial ways to improve efficiencies and reduce costs.

Our extensive inventory of drilling locations allows us to contract rigs for years at a time, often at discounted rates. Our large size does not make Devon immune to price increases, but we can lessen the impact with careful planning, close cooperation with the service suppliers and attention to the bottom line.

The importance of unconventional oil and gas resources is increasing in North America. What unconventional resources is Devon developing?

Devon was an early leader in developing unconventional resources when we began producing natural gas from coal beds in New Mexico's San Juan Basin in the 1980s. In addition to the San Juan Basin we also have a significant coalbed gas project in the Powder River Basin in Wyoming and are piloting others in Wyoming's Wind River Basin and in western Canada.

Perhaps the most exciting unconventional gas play in the United States is the Barnett Shale in north Texas. With our current production from the Barnett approaching 600 million cubic feet equivalent per day, Devon is by far the largest producer in the play. Leveraging our success in the Barnett Shale, we are also pursuing similar unconventional formations including the Woodford and Caney shales in Oklahoma.

In addition to natural gas, North America also holds abundant unconventional oil resources in the oil sands of western Canada. Devon is the only U.S. independent currently active in the Canadian oil sands. Our Jackfish project in eastern Alberta is expected to produce 35,000 barrels of oil per day in 2008. We are currently evaluating a potential extension to Jackfish that could double the output to 70,000 barrels per day. As conventional North American resources are being depleted, unconventional oil and gas are growing in significance. Devon is well positioned to participate in that growth.

Devon had meaningful reserve growth in 2005, but you are not forecasting production growth in 2006. Why is that?

We were very successful at increasing proved reserves in 2005. Extensions, discoveries and performance revisions totaled 439 million equivalent barrels. This was nearly double Devon's 2005 production of 226 million barrels. However, we also sold non-core producing properties in the year comprising proved reserves of 183 million barrels. Prior to sale, the divested properties contributed 10 million equivalent barrels to 2005 production. Therefore, excluding production from the divested properties, our 2006 production forecast of 217 million barrels is about equal to 2005.

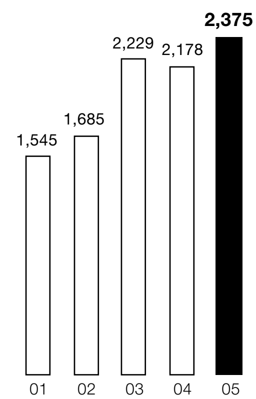
Due to the multi-year investment cycle of many large-scale oil and gas developments, capital outlays and oil and gas reserve additions often precede growth in production. This is the case with Devon—we expect much higher production in 2007, between 232 and 236 million equivalent barrels. Furthermore, we anticipate additional production growth in 2008 and beyond. This growth is largely the result of multi-year development projects that are nearing completion. Examples include our Jackfish project in Canada, the ACG field in Azerbaijan and the Polvo project in Brazil. These three projects in combination are expected to contribute more than 85,000 barrels per day to Devon in 2008.

In light of Devon's international exploration activities, do you expect more of your production to come from outside North America in the future?

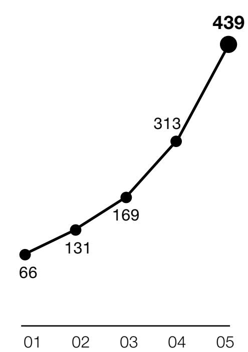
Devon is primarily a North American company, with approximately 88% of our oil and gas production coming from the United States and Canada. In support of this concentration, a proportionate share of our 2006 capital budget for drilling, development and facilities is allocated to projects in North America. However, Devon's production from countries outside North America is expected to increase in 2007. Increases from the ACG field in Azerbaijan and development of our Polvo discovery offshore Brazil will be the main contributors.

Longer term, shifts in the geographic distribution of Devon's production mix will be opportunity driven. Devon is pursuing large-scale exploration opportunities in Canada, the lower 48, the Gulf of Mexico and select countries outside North America. Disproportionate success in one of these geographical regions could shift our production mix toward that region.

WELLS DRILLED



RESERVE ADDITIONS FROM EXTENSIONS, DISCOVERIES AND PERFORMANCE REVISIONS
(MMBoe*)



*Gas converted to oil equivalent at the ratio of 6Mcf:1Bbl.

Devon drilled a record 2,375 wells in 2005 with a 97% success rate. This led to our most successful year ever adding reserves with the drill bit.

compassionate /com•pas•sion•ate/ "I wouldn't be here today if it weren't for Devon's compassion and willingness to take a chance on people they don't even know."

Hoa Tran
Devon Scholar
OKLAHOMA CITY UNIVERSITY

"When my mother and father immigrated to the United States from Vietnam 11 years ago, they were hoping to give me, my sister and two brothers a better chance for education and success. Some of those opportunities seemed to fade five years ago when my father passed away.

"Those opportunities are brighter today because of Devon Energy's support for Oklahoma City University's Clara Luper Scholarship Program for inner-city students. As a Devon Energy Scholar, I'm studying biology and ultimately plan to become an optometrist. I wouldn't be here today if it weren't for Devon's compassion and willingness to take a chance on people they don't even know. I know about business, and it's all about profit. But this company takes part of its profits to share with others so they can profit too.

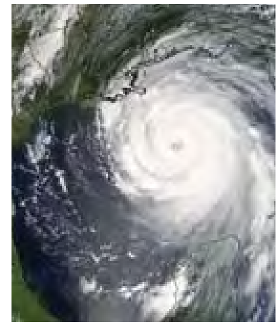
"Hopefully, when I'm an optometrist, I will be able to share as well. Hopefully, this experience will help me to remember."

Community Partners

At Devon, we are more than an energy producer, more than an employer, more than an innovator and more than a good place to invest. While we are proud to be all of those things, what defines us as a company is our desire to be a good neighbor.

From the Louisiana coast to the northern edge of Canada, and from the inner city of Rio de Janeiro to the congested streets of Cairo, Devon touches the lives of people who live and work around us. Our employees volunteer as tutors in Oklahoma City and Houston, we support a safety initiative for young people in Alberta, and we build schools in Nigeria. Devon supports volunteer fire departments and sheriffs' offices from Texas to Montana, and our contributions to community programs stretch even farther.

Reaching out to help others is part of our role as a good corporate citizen, just as it is our role to produce energy and create value for our investors. What is good for our communities is good for us because healthy communities nurture successful companies.



Despite the massive size of hurricanes Katrina and Rita, Devon's field operations weathered the storms without an employee injury or environmental mishap.

Hurricane Relief / In the aftermath of hurricanes Katrina and Rita, Devon reached out with contributions and volunteers to help victims begin the process of mending lives shattered by the storms. Immediately following Katrina, Devon reactivated its charitable foundation, matching more than $64,000 in employee contributions made to assist dozens of colleagues affected by the storms in Louisiana and Texas. Devon also pledged $2 million to community agencies assisting hurricane victims along the Gulf Coast.

The 2005 Gulf of Mexico hurricanes did extensive damage to coastal communities such as Buras, Louisiana. Devon employees responded generously with donations of time and money.

Devon employees stepped up as volunteers, working both before and after the devastation hit. In Houston, our employees sorted clothing, toys and other goods donated to Hurricane Katrina evacuees. The volunteers played an important role in processing donations quickly so they could be delivered immediately to people who needed them.

Dozens of volunteers from Oklahoma City manned a hotline to assist more than 700 Devon employees and their families as they rushed to leave Houston in front of Hurricane Rita.

In west Texas, employees in Devon's Midland office helped reopen an abandoned apartment complex to assist people displaced by the hurricanes. The volunteers spent a weekend deep cleaning apartments that had been scheduled for demolition.

Community Outreach / Devon has a stake in the communities where we do business. We not only work there, we live there, go to church there and our children attend school there. We consider ourselves part of the communities where we operate, and it is our role to offer leadership and support in ways that protect the environment, promote safety and enhance the quality of life.

For many of our employees, it is not enough to come to work each day to do their jobs. Some also serve as ambassadors in their communities, creating points of contact where lasting relationships can form. They serve on school boards

Pipeline foreman Billy Hill (left) and production foreman Dickie Smith volunteer in their communities as Devon Ambassadors. Devon's community outreach programs were recognized for their excellence in 2005.

Lease analyst Jill Roberts tutors Mercedes Garcia at Mark Twain Elementary School in Oklahoma City. Student test scores have shown notable improvement since the tutoring program was initiated in 2003.

Engineer Brian Harrison ties four colored flags commemorating a traditional ground blessing ceremony on the site of the Jackfish oil sands project in Alberta, Canada. At Jackfish, Devon is striving to conduct its operations in a manner which is respectful and responsive to the needs and concerns of the local communities.

and city councils and volunteer as youth league coaches. They speak to civic groups and school classes about Devon and the energy industry. They stop to answer questions on street corners, from their vehicles or walking down grocery store aisles.

Devon promotes public safety as well, contributing financial support to dozens of volunteer fire departments each year. The company is the founding sponsor of Wise Eyes, a county-based crime watch program adopted by sheriffs' offices in Texas, New Mexico and Wyoming.

Our solid record of community outreach and stewardship was recognized in 2005 by *Oil & Gas Investor* magazine, which named Devon Best Corporate Citizen as part of the publication's annual Excellence Awards.

Advocate for Education / Whether they are learning their ABCs or studying advanced microbiology, Devon supports students. We are investing in the future by supporting youth and education as volunteers, financial contributors and mentors. From Houston to Oklahoma City to Calgary, Devon seizes the opportunity to enrich the educational experience.

Devon volunteers are active in Houston's Communities in Schools program, serving as role models for at-risk students attending inner-city schools. In Oklahoma City, about 200 volunteer tutors are contributing to continued improvement in math and reading test scores at Mark Twain Elementary School. Devon has been a partner for three years with the school that is located in a disadvantaged neighborhood near downtown Oklahoma City.

In Alberta, Devon supports the SMARTRISK initiative, advocating personal safety to thousands of middle school and high school students in Canada. By teaching safety education early, we benefit our communities and the company. Some of the students who attend our presentations could one day be summer interns or Devon employees.

The Devon-sponsored Clara Luper Scholarship program at Oklahoma City University is named for a prominent Oklahoman and national civil rights activist. The program funds tuition, fees, books and living expenses for students who might not otherwise have an opportunity to attend a university. Currently 10 Devon scholars are on campus.

His Excellency, Asiwaju Bola Ahmed Tinubu, executive governor of Lagos State, hosts Devon's President John Richels during a 2005 visit to Nigeria. Devon has funded primary and secondary education in Nigeria since 2004.

International / Outside North America, Devon's community support efforts coincide with the company's exploration and production operations in countries such as Brazil, Nigeria and Egypt.

Since 2002, Devon has supported efforts to help young children exposed to violence in the inner-city of Rio de Janeiro. The A Casa da Arvore project involves about 400 children and their families. The program provides free psychological counseling and offers other programs to strengthen family and social ties.

In Nigeria, Devon invests $1 million annually to provide students opportunities to pursue degrees in petroleum engineering, petroleum law, geology and geophysics at Nigerian universities as well as institutions in the United States and Europe. Devon also funds the renovation and construction of primary and secondary schools in Nigeria, benefiting more than 4,100 students since the program began in 2004.

In Egypt, Devon is a key member of the Society for Road Safety, which provides education and funding for traffic safety projects in Cairo. We also provide food, blankets and medical supplies to poor families and orphans in the nation's central Nile delta region.

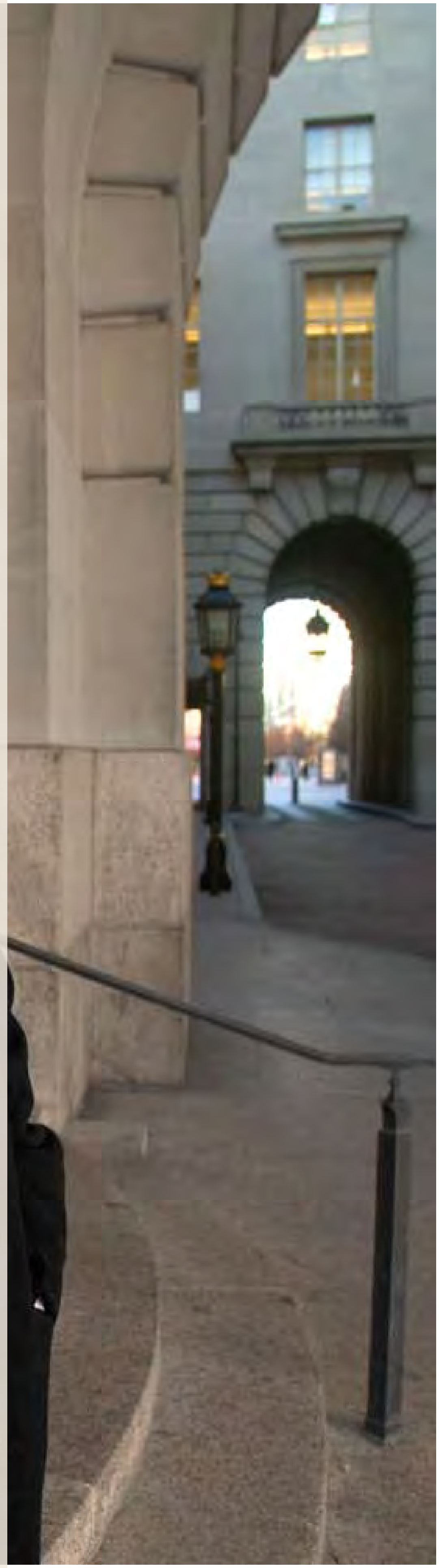
committed /com•mit•ted/ "I use Devon as an example for other companies to follow because of its commitment and hard work. The company set a tone for success early and has emerged as an industry leader."

Roger Fernandez
Team Leader
NATURAL GAS STAR PROGRAM
ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C.

"Devon joined the Environmental Protection Agency's Natural Gas STAR Program in 2003 and is among 32 natural gas production companies working under the voluntary program to reduce methane emissions. Since joining, the company has shown tremendous dedication.

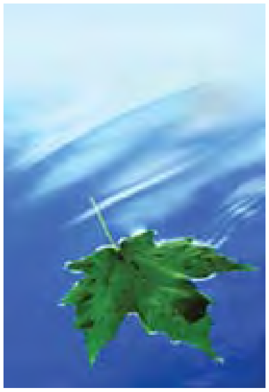
"I use Devon as an example for other companies to follow because of its commitment and hard work. The company set a tone for success early and has emerged as an industry leader. Devon was named Natural Gas Star Rookie of the Year in 2004, and in 2005, the company was named Natural Gas STAR Production Partner of the Year. What makes Devon stand out among the very best in the industry is the mechanism put in place to ensure its commitment to the program is achieved. That mandate was established early by Devon's top executives, who challenged employees to be diligent and comprehensive in finding as many reduction methods as possible.

"That challenge has become part of Devon's corporate culture. Methane emission reduction has become so important that friendly competition between divisions is helping to drive the effort."



ger Fernandez / *Team Leader* – NATURAL GAS STAR PROGRAM, ENVIRONMENTAL PROTECTION AGENCY, WASHINGTON, D.C.

Environmental, Health and Safety



Devon and the Calgary-based SEEDS Foundation have joined to educate school children in Alberta about the importance of water conservation.

Devon's oil and gas production operations stretch from the Gulf of Mexico's deep water to the Canadian Arctic and several other continents around the world. We are results oriented and focused on achievement. But our successes would be hollow if they were not accomplished in ways that ensure the safety of our employees and respect for the environment.

Whether we are leading the way in the massive Barnett Shale play in north Texas or re-establishing exploration in Canada's frozen Beaufort Sea, Devon has a record of achievement in safety and environmental stewardship.

Workplace safety, water conservation and climate change are issues we work with every day at Devon. As an energy company, it is our role to find and produce the oil and natural gas necessary to keep pace with the world's growing demand for energy. It is also our role to create safe work environments, conserve natural resources and limit greenhouse gas emissions.

Emission Reduction / Devon pursues cost-effective methane emission reduction methods that extend beyond regulatory requirements in the United States and Canada. The company's record is well documented with the U.S. Environmental Protection Agency and the Canadian Standards Association.

In the United States, Devon has recorded more than 15 billion cubic feet of methane emission reductions since 1990. The EPA's Natural Gas STAR Program has recognized Devon's performance two years in a row. In 2004, Devon was named Rookie of the Year following its first year of participation. In 2005, the company was selected as Production Partner of the Year.

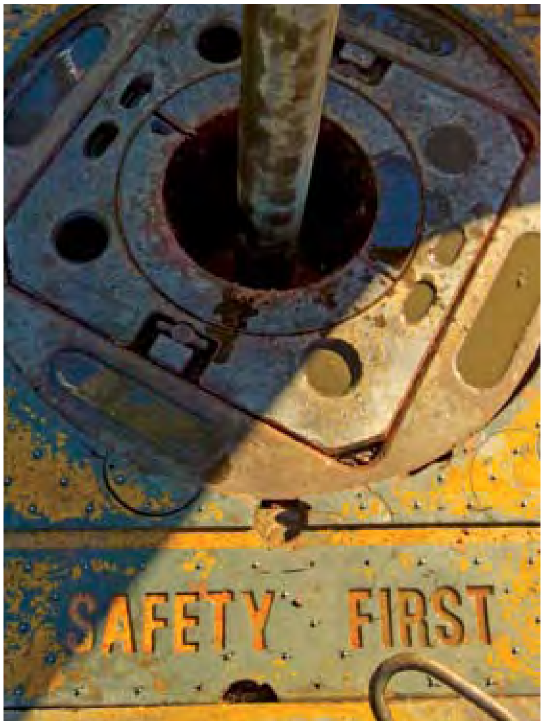
Devon's participation in the Canadian Greenhouse Gas Challenge and Registry reflects further dedication to greenhouse gas emission reduction. The company is recognized as a Gold Champion Level Reporter, which is the highest level of achievement with the Canadian program. Under the voluntary government/industry partnership, Devon has recorded a cumulative reduction of 6.7 million metric tons of carbon dioxide equivalent from 1994 through 2004.

Devon operates in many arid regions where water is a vital concern. The company has been recognized for its water conservation efforts.

In addition to our reduction efforts in the field, Devon is pursuing other ways to address air quality issues. In Oklahoma City, Devon sponsors the Association of Central Oklahoma Governments' Clean Air Campaign, promoting public awareness for air quality issues. In Houston, Devon encourages employees to use alternative forms of transportation. As a result, 70% of the company's Houston workforce either carpools or rides the bus to work. The EPA recognized Devon's commuter program by naming the company as one of its 20 Best Workplaces for Commuters among Fortune 500 companies. Devon ranked 13th in 2005, marking its second year on the list.

About 70% of Devon's downtown Houston employees either carpool or use public transportation in their daily commutes.

Conservation / Conservation of natural resources is a fundamental part of our role as environmental stewards, and water is a central focus. We are steadfast in our compliance with regulatory requirements for water conservation in oil and natural gas fields, and we continue to



This simple reminder on the floor of a drilling rig represents the importance of safety at Devon. The promotion of safe work practices is a constant message to all of our employees and contractors.

search for better ways to protect and conserve water resources.

In Wyoming, where water is a by-product of coalbed natural gas production, Devon's conservation efforts have received repeated recognition from state and federal agencies. In Canada, we have moved our water conservation efforts beyond the oil and gas fields and into the schools.

Devon and the Calgary-based SEEDS Foundation have joined to create the SEEDS Alberta Centennial Water Challenge, commemorating Alberta's 2005 centennial year through water conservation and stewardship. More than 13,000 children have participated in the educational program that stresses how individuals can conserve water in small ways, such as turning off the tap while brushing their teeth and only running dishwashers when they are full.

The Canadian Association of Petroleum Producers honored Devon's commitment to water management with its 2005 President's Award. The industry group recognized the company's water usage tracking and reporting efforts as well as its community involvement and educational programs.

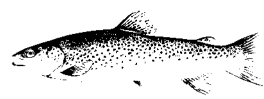
In the United States, the Interstate Oil and Gas Compact Commission honored Devon with its 2005 Chairman's Stewardship Award for exemplary efforts in conservation and environmental protection. The organization recognized Devon for its accomplishments in methane emission reductions as well as its role in establishing a 300-acre desert habitat restoration project along the Santa Cruz River south of Tucson, Arizona.

Safety / While we are dedicated to environmental responsibility, our safety record reflects equal commitment to the well-being of our employees and contractors. Solid safety records do not come easily. They require initiative and persistence to ensure workers adopt the habits necessary to avoid on-the-job injuries.

Devon's SAFE observation program is an example of our ongoing effort to promote safety to Devon employees and our contractors. The company has seen significant results under the program, based on frequent peer reviews of field operations and immediate positive feedback. In the fourth quarter of 2005, Devon recorded a 64% reduction in employee injury rates where the SAFE program is in place. Among contractors working for Devon, there was a 43% decrease in injury rates under the program.

Despite the challenges of working offshore, Devon's Panyu project in China has logged more than two million man hours without a lost-time injury. And in the Gulf of Mexico, Devon consistently wins recognition for safety performance. In 2005, the Lafayette and Lake Charles, Louisiana districts of the federal Minerals Management Service honored Devon with two District Safety Awards for Excellence. Our 163 offshore personnel finished the year without a single missed day of work because of an on-the-job injury. Meanwhile, our U.S. midstream operations won the President's Award for Safety Improvement from the Gas Processors Association for achieving a 25% decrease in worker injuries in 2005.

Pygmy Owl
Scientific Name: *Glaucidium brasilianum*
Conservation status: *Endangered*



Brown Trout
Scientific Name: *Salmo trutta*

Indian Paintbrush
Scientific Name: *Castilleja*

Devon's concern for wildlife and our natural surroundings are evident wherever we operate. The wildlife habitat restoration project Devon established in Arizona is home to the endangered Pygmy Owl. Cool Rocky Mountain streams are home to the Brown Trout and the state flower of Wyoming, the colorful Indian Paintbrush, is found in many of the western states where we operate.

trustworthy /trust•wor•thy/ "Devon is a trustworthy company that understands the needs of the Indian reservation and works in cooperation with the tribal community. We not only value their business, we value their friendship."

Burt Freese
Superintendent
HIGH COUNTRY OIL FIELD SERVICES
LANDER, WYOMING

"A day rarely goes by when we're not involved in a project with Devon Energy in western Wyoming. High Country Oil Field Services is a company based in Lander and owned by an enrolled Shoshone Tribal member. We do excavation, oil field construction, install pipelines and provide trucking services in and near the Shoshone-Arapahoe Indian Reservation.

"After more than a decade of working with Devon, we have grown to respect their integrity and admire the way they do business. The company is a proven friend of the Shoshone and Arapahoe tribes, ensuring that its operations on Indian lands are among the best at following tribal rules and regulations. Devon works closely with the Tribal Employment Rights Office to offer jobs and business opportunities that benefit the tribal community. About 80% of High Country's employees are tribal members, and many of Devon's employees in the area are either tribal members or related to someone who is.

"Devon is a trustworthy company that understands the needs of the Indian reservation and works in cooperation with the tribal community. We not only value their business, we value their friendship."

Portfolio of Oil and Gas Properties

Devon is the United States' largest independent producer of oil and natural gas. By independent we mean that we do not own oil refineries or sell gasoline and other refined products to the public. We simply explore for crude oil and natural gas and produce and sell those products. An important measure of our success is whether or not we find more proved reserves of oil and gas than we produce each year. If we produce more than we find, we get smaller; if we find more than we produce, we grow. On this scale, 2005 was a very good year at Devon.

Through successful drilling projects, particularly in the United States and Canada, we added 439 million equivalent barrels of proved reserves. These additions nearly doubled the 226 million equivalent barrels we produced in 2005. We invested $4 billion of capital in the projects that led to the reserve additions. On a unit-cost basis our results compared very favorably to industry averages. In the following pages, we will review some of Devon's major oil and gas properties and important reserve growth projects.

A BALANCED STRATEGY

Of the $4 billion of capital Devon invested in oil and gas projects in 2005, over $3.5 billion went toward lower-risk, exploitation and development drilling. Development wells are drilled in areas where oil and gas have already been found. Devon's Barnett Shale natural gas field in north Texas exemplifies an outstanding development project. To date, we have drilled more than 2,100 Barnett Shale wells, with almost no dry holes, and thousands of potential well locations remain to be drilled.

Development projects alone, however, cannot assure sustainable growth. When a project area is fully exploited, new opportunities must be waiting in inventory. This is the role of exploration. Exploratory wells are drilled in unproved areas where production does not currently exist. In 2005, Devon invested almost $500 million on high-impact exploration projects. We believe this balance of investing in both low-risk development and high-impact exploration will enable Devon to continue growing its oil and gas reserves far into the future.

A NORTH AMERICAN FOCUS

Following our success adding new oil and gas reserves in 2005, we finished the year with more than 2.1 billion equivalent barrels of proved reserves. More than 88% are in the United States and Canada. In the first half of 2005, we identified a number of mature, non-core North American properties to sell. It is

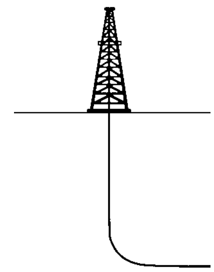
This rig is drilling in the Barnett Shale near Cleburne, Texas. Devon drilled its 2,000th Barnett Shale well in 2005.

notable that Devon increased reserves year over year, despite divesting 183 million equivalent barrels and producing 226 million barrels.

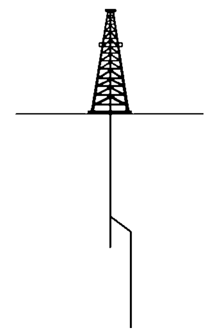
Geographically, Devon's North American operations comprise the U.S. onshore, the offshore Gulf of Mexico and Canada. With stable governments and tax structures, ready access to markets and extensive energy infrastructures, the United States and Canada are among the world's best places for us to do business.

Barnett Shale / The Barnett Shale in the Fort Worth Basin of north Texas is Devon's largest asset, determined by both proved reserves and production. On December 31, 2005, the Barnett represented 19% of the company's reserve base and accounted for 15% of our total 2005 oil and gas production. The Barnett Shale has rapidly grown to become the largest gas field in the state of Texas and has secured Devon's position

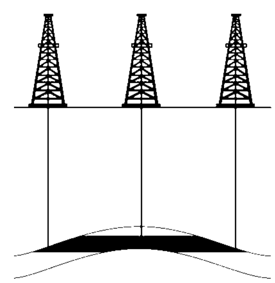
HORIZONTAL



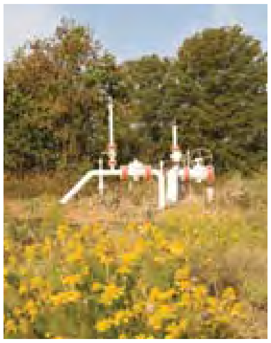
SIDETRACK



DELINEATION



These drawings illustrate three well types. A *horizontal* well penetrates more reservoir rock than a vertical well. Devon makes extensive use of horizontal drilling in the Barnett Shale. A *sidetrack* can be drilled around a blocked wellbore or to reach a different targeted location. *Delineation* wells are drilled to test the boundaries of a previously penetrated oil or gas reservoir.



A Barnett Shale pipeline valve station is part of Devon's vast gas gathering system serving the north Texas area. Devon's cumulative operated Barnett Shale gas production surpassed one trillion cubic feet in 2005.

as the state's largest natural gas producer. In 2005, we reached a significant milestone in the life of the field, when cumulative gross production from Devon's operated wells reached one trillion cubic feet of natural gas.

The Barnett Shale is considered an unconventional reservoir because of its low permeability. It requires fracturing or other stimulation techniques before it will produce its gas. Unconventional gas is gaining importance throughout North America as demand increases and mature, conventional resources are depleted.

When Devon acquired its Barnett Shale properties in early 2002, we booked 310 million equivalent barrels of proved reserves. Since then, we have produced about 125 million equivalent barrels from the shale. Remarkably, vigorous and innovative field development has allowed us to add more new reserves than we have produced. At year-end 2005, the Barnett Shale accounted for 408 million equivalent barrels of proved reserves, demonstrating the sustainability of this exceptional property.

We plan to drill 325 wells on our Barnett Shale acreage in 2006. More than three-quarters of the wells will be horizontals. In 2006, about 70 of our wells in the Barnett Shale will be 20-acre infill wells. The successful infill pilot program we began in 2005 tested the results of drilling wells more closely together. Reservoir data tell us that the infill wells are encountering incremental gas resources, not just accelerating production. Infill drilling is one of the ways we plan to increase Barnett Shale production in 2006, to a targeted exit rate of 630 million cubic feet equivalent per day, net to Devon.

Devon produces more than 200 million cubic feet of gas equivalent per day from the Carthage area in east Texas.

Carthage / Carthage in east Texas is another of Devon's low-risk natural gas development assets. We have accelerated drilling at Carthage in the past few years, increasing both reserves and production. In 2005, our reserve additions were more than double field production. Multiple producing formations underlie our Carthage acreage, including conventional and unconventional reservoirs. Currently, we produce about 220 million cubic feet equivalent per day at Carthage. In 2006 we plan to drill 140 wells, including a few 20-acre infill wells.

A steel drilling caisson was used to drill Devon's Paktoa well in the Beaufort Sea in far northern Canada. Devon is the largest exploratory land holder in the Mackenzie Delta and Beaufort Sea areas.

Washakie / The Washakie field in south central Wyoming is another important low-risk source of gas production for Devon. We increased drilling activity at Washakie by nearly 50% in 2005. We plan to increase activity again in 2006, drilling as many as 100 wells from our multi-year inventory of locations. Successful drilling and improvements in the natural gas transmission system helped boost production to a daily average of about 90 million cubic feet equivalent in 2005.

Welders construct facilities for Devon's Jackfish thermal oil sands project in eastern Alberta. Jackfish is expected to produce 35,000 barrels of oil per day.

Bossier Exploration / Devon is exploring for gas in the Bossier trend in north Louisiana on our lease position of about 200,000 net acres. We own the mineral interests in much of this acreage, enabling us to keep a larger share of oil and gas revenues and enhancing project returns. We drilled exploratory wells on two Bossier prospects in 2005. One of them, on the Vixen prospect, was a discovery. In 2006, we plan to continue 3-D seismic evaluation and delineation drilling at Vixen and test three additional Bossier prospect areas.

Western Canadian Sedimentary Basin / Canada is Devon's second largest producing region, following the U.S. onshore. We have significant asset positions in most of western Canada's producing areas. Canada accounted for 30% of our proved reserves at year-end 2005 and provided 27% of 2005 oil and gas production. As in the onshore United States, we were very successful adding new reserves in Canada in 2005. Discoveries, extensions and performance revisions combined for 184 million equivalent barrels of proved reserve additions. This was nearly three times our Canadian production of 62 million barrels.

Our major producing areas within Canada include the Deep Basin and Peace River Arch, which encompass lands in British Columbia and western Alberta. Devon owns interests in numerous oil and gas producing fields in these areas. The Deep Basin, with its liquids-rich gas, delivered particularly strong results in 2005.

Devon's producing and drilling platform serves our Panyu project in the South China Sea. Panyu began producing in 2003 and has delivered more than 50 million barrels of oil to date.

Discoveries, extensions and performance revisions yielded 25 million equivalent barrels of reserve additions, versus production of 13 million equivalent barrels.

Along the border of Alberta and Saskatchewan, Lloydminster is a focused development area for Devon in Canada. In 2005, we acquired 165,000 net acres in a portion of the Lloydminster area called Iron River. We plan to drill up to 800 wells and increase production to about 30,000 barrels per day by 2010 at Iron River. Devon added 27 million barrels of new reserves at Lloydminster in 2005, including three million barrels acquired in the Iron River purchase.

Our largest Canadian reserve growth driver in 2005 was the 100% Devon-owned Jackfish project. This thermal heavy oil project is in the oil sands of eastern Alberta. We booked the first 118 million barrels of this estimated 300 million barrel resource in 2005.

Associated with the Jackfish project, we are laying two 200-mile pipelines between Jackfish and Edmonton, Alberta. These pipelines will enable us to transport lighter blending stocks to Jackfish and to transport the blended product to multiple markets via Edmonton. We expect to begin producing oil from Jackfish in the second half of 2007, and to ramp up to 35,000 barrels of oil per day in 2008.

We are also considering expanding Jackfish to the west of the current project area. A second Jackfish phase could add another 35,000 barrels per day to production and another 300 million barrels of resource potential.

Frontier Exploration / At year-end 2005, Devon was drilling the first exploratory well in the Beaufort Sea in 15 years. Drilled from a massive steel drilling caisson frozen into the Arctic ice, the Paktoa well targeted a significant natural gas resource. The well reached a total depth of 7,800 feet in February 2006 and is currently being evaluated.

Gulf of Mexico / Despite a severe hurricane season, Devon carried out a busy drilling program in the Gulf of Mexico in 2005. We drilled several successful wells on the shallow water shelf, continued development of the Magnolia field and drilled important evaluation wells on two of our deepwater discovery blocks.

Shelf Exploration / Although the 2005 property divestiture program included about 40% of our shelf reserves, we retained a broad inventory of shallow water drilling opportunities. In 2005, Devon drilled three successful exploration wells, at Racer, Chopin and Big Bend. The Racer discovery on West Cameron 575 came online in June at more than 20 million cubic feet of gas per day. First production from Chopin on Eugene Island 334 is expected in the second half of 2006. Completion of Big Bend is planned for early 2007. Devon operates all three discoveries with 100% working interests in Racer and Chopin and a 50% working interest in Big Bend. We plan to drill as many as six shelf exploration prospects in 2006.

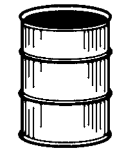
Deepwater Gulf / In the deepwater Gulf of Mexico, development continues on the Magnolia project on Garden Banks 783. Magnolia began producing in late 2004 and ramped up throughout 2005 as we completed additional wells. Six of the eight planned wells were producing about 10,500 equivalent barrels per day net to Devon's interest at year-end. We expect to bring the remaining two wells on production in the first half of 2006.

We have also begun completion operations on two wells in the 50%-owned Merganser gas development project on Atwater Valley 37. Merganser will produce into the Independence Hub, which is scheduled to be completed in early 2007. Devon's share of Merganser production is expected at 50 million cubic feet of gas per day.

Deepwater projects typically span several years between initial discovery and first production. In 2005, Devon moved two promising deepwater discoveries closer to development and eventual first production. We drilled successful delineation wells in 2005 on Cascade, a 2002 discovery, and on the 2004 Jack discovery.

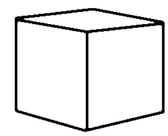
Cascade, Jack and a third discovery, St. Malo, are located in the deepwater Walker Ridge area and were drilled into what is known as the lower Tertiary trend. The 2005 delineation wells at Cascade encountered encouraging hydrocarbon columns and extended our view of the boundaries of the reservoir. The delineation well on the Jack prospect encountered net

OIL AND NATURAL GAS LIQUIDS



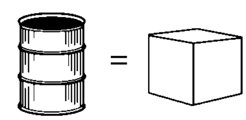
Barrel - 42 Gallons

NATURAL GAS



Mcf - Thousand cubic feet
MMcf - Million cubic feet
Bcf - Billion cubic feet

BOE / MCFE



1 Barrel = 6,000 cubic feet of gas
Boe = Barrel of oil equivalent
Mcfe = Thousand cubic feet of gas equivalent

Devon's production is about 40% oil and natural gas liquids and 60% natural gas. To facilitate comparisons, we often discuss our production volumes on either an oil equivalent or gas equivalent basis. The illustrations above explain the relationship of oil to gas equivalents.

Devon's BM-C-8 discovery well was drilled offshore Brazil in 2004. We expect first oil production from the Polvo development in 2007.

pay in excess of the 350 feet encountered in the 2004 discovery well.

We returned to the Jack location in February 2006 to conduct an extended production test. The test results will be instrumental in determining a development plan for the project. Devon has 25% working interests in Cascade and Jack and a 22.5% working interest in St. Malo.

BEYOND NORTH AMERICA

Outside North America in 2005, we began developing a recent discovery offshore Brazil and made two discoveries offshore Equatorial Guinea in West Africa. We are also nearing an important milestone in Azerbaijan.

Brazil / Devon began facilities construction in 2005 on the offshore Polvo project on Block BM-C-8 in Brazil's Campos Basin. We believe Polvo is at least a 50 million barrel project with production capability of 50,000 barrels per day. Furthermore, additional drilling on the block in 2006 could significantly expand the size of the project. Devon operates Polvo with a 60% working interest, and we expect to commence production in 2007. In addition to the wells at BM-C-8, we also plan exploratory tests of Blocks BM-C-30 and BM-C-32 in 2006. These are deepwater prospects with significant reserve potential.

West Africa / Devon made two promising discoveries in the waters of Equatorial Guinea in 2005. The Esmeralda discovery was drilled on Block B, which is also the location of our largest international producing property, the Zafiro field. In 2006, we plan to reprocess seismic data and in 2007, drill a follow-up well to Esmeralda. Our other discovery in Equatorial Guinea was on the Venus prospect on Block P. We are conducting additional seismic work on this discovery and plan three more wells in 2006. Additionally, we plan to drill a well offshore Nigeria in 2006.

Azerbaijan / In the first half of 2007, we will reach an important milestone in Azerbaijan, when Devon's 5.6% carried interest in the five billion barrel ACG field reaches payout. Under the terms of our ownership in the field, third parties have been paying Devon's operating and capital costs in exchange for receiving most of our share of the oil revenues. At payout in 2007, Devon's share of ACG production is expected to increase from about 1,300 barrels per day to at least 30,000 barrels per day. This will be a significant driver of Devon's forecast production growth in 2007.

11-Year Property Data (1)

	1995	1996	1997	1998
Reserves *(Net of royalties)*				
Oil *(MMBbls)*	313	351	219	166
Gas *(Bcf)*	860	1,131	1,403	1,440
NGLs *(MMBbls)*	16	18	24	21
Oil, Gas and NGLs *(MMBoe)* (2)	472	558	477	427
10% Present Value Before Income Taxes *(Millions)* (3)	$ 1,872	3,952	2,100	1,375
Production *(Net of royalties)*				
Oil *(MMBbls)*	28	30	29	20
Gas *(Bcf)*	109	116	180	189
NGLs *(MMBbls)*	1	2	3	3
Oil, Gas and NGLs *(MMBoe)* (2)	47	52	62	55
Average Prices				
Oil *(Per Bbl)*	$ 15.07	17.49	17.03	12.28
Gas *(Per Mcf)*	$ 1.44	1.82	2.04	1.78
NGLs *(Per Bbl)*	$ 10.62	13.78	12.61	8.08
Oil, Gas and NGLs *(Per Boe)* (2)	$ 12.49	14.90	14.51	11.09
Unit Production and Operating Expense *(Per Boe)* (2)	$ 4.69	5.24	4.63	4.29

(1) All the years shown exclude results from Devon's operations in Indonesia, Argentina and Egypt that were discontinued in 2002. Devon acquired new assets in Egypt and Indonesia in the April 2003 Ocean merger that are included in Devon's continuing operations since 2003. Data has been restated to reflect the 1998 merger of Devon and Northstar and the 2000 merger of Devon and Santa Fe Snyder in accordance with the pooling-of-interests method of accounting.
(2) Gas converted to oil at the ratio of 6Mcf:1Bbl. Natural gas liquids converted to oil at the ratio of 1Bbl:1Bbl.
(3) See note 2 on page 23.

Operating Statistics by Area

	Permian	Mid-Continent	Rocky Mountains	Gulf Coast	U.S. Offshore	Total U.S.	Canada	International	Total Company
Producing Wells at Year-End	8,566	5,820	5,696	3,788	628	24,498	6,844	593	31,935
2005 Production *(Net of royalties)*									
Oil *(MMBbls)*	8	1	1	2	13	25	13	26	64
Gas *(Bcf)*	42	195	98	128	92	555	261	11	827
NGLs *(MMBbls)*	2	11	1	3	1	18	6	—	24
Oil, Gas and NGLs *(MMBoe)* (1)	17	44	19	26	30	136	62	28	226
Average Prices									
Oil price *($/Bbl)*	$ 50.48	53.33	52.09	52.75	32.96	41.64	26.88	41.16	38.44
Gas price *($/Mcf)*	$ 6.94	6.53	6.95	7.42	7.95	7.08	6.95	3.76	6.99
NGLs price *($/Bbl)*	$ 25.40	25.98	13.04	31.69	30.61	26.68	37.19	22.81	28.96
Oil, Gas and NGLs *($/Boe)* (1)	$ 43.08	36.17	41.71	43.56	40.58	40.21	38.17	39.76	39.59
Year-End Reserves *(Net of royalties)*									
Oil *(MMBbls)*	91	5	22	11	44	173	253	223	649
Gas *(Bcf)*	285	2,282	1,074	1,120	403	5,164	2,006	126	7,296
NGLs *(MMBbls)*	23	124	8	38	4	197	49	—	246
Oil, Gas and NGLs *(MMBoe)* (1)	161	509	209	237	116	1,232	636	244	2,112
Year-End Present Value of Reserves *(Millions)* (2)									
Before income tax	$ 2,832	6,292	3,336	3,817	3,896	20,173	9,912	5,525	35,610
After income tax	$					13,276	6,631	3,667	23,574
Year-End Leasehold *(Net acres in thousands)*									
Developed	309	678	538	524	384	2,433	2,066	341	4,840
Undeveloped	494	455	1,148	471	1,635	4,203	6,681	10,947	21,831
Wells Drilled During 2005	232	405	431	216	14	1,298	1,020	57	2,375
Capital Costs Incurred *(Millions)* (3)									
2005 Actual (4)	$ 224	745	256	418	487	2,130	1,669	340	4,139
2006 Forecast	$ 170-180	1,155-1,205	250-265	545-570	555-625	2,675-2,845	1,380-1,440	595-630	4,650-4,915

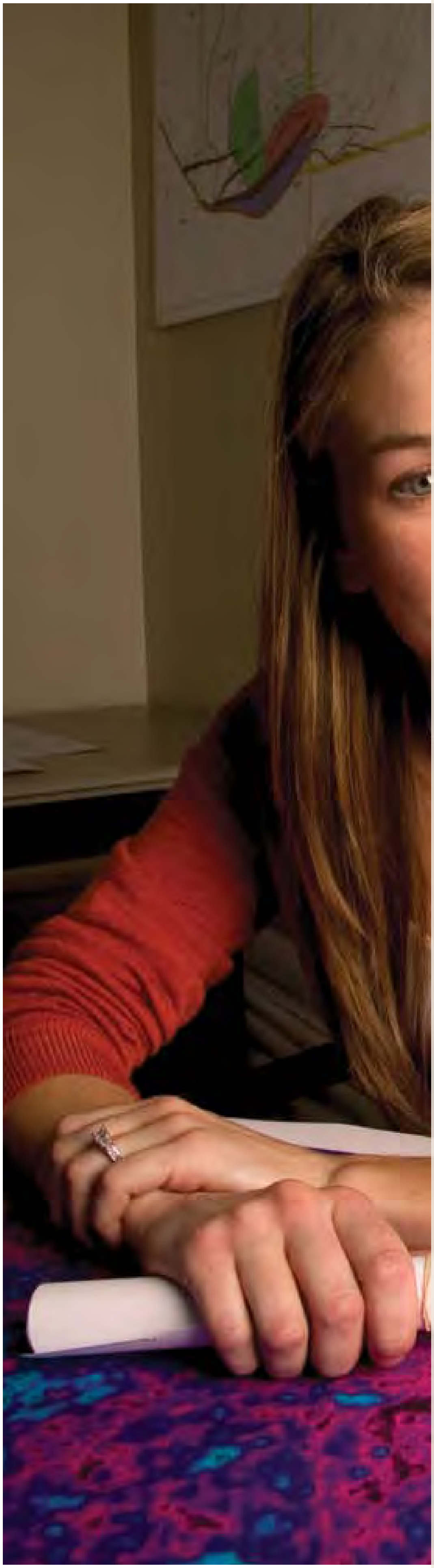
(1) Gas converted to oil at the ratio of 6Mcf:1Bbl. Natural gas liquids converted to oil at the ratio of 1Bbl:1Bbl.

(2) Estimated future revenue to be generated from the production of proved reserves, net of estimated future production and development costs, discounted at 10% in accordance with SFAS No. 69, Disclosures about Oil and Gas Producing Activities. Devon believes that the pre-tax 10% present value is a useful measure in addition to the after-tax value as it assists in both the determination of future cash flows of the current reserves as well as in comparing relative value among peer companies. The after-tax present value is dependent on the unique tax situation of each individual company while the pre-tax present value is based on prices and discount factors which are consistent from company to company. We also understand that securities analysts use this pre-tax measure in similar ways.

(3) 2005 actual costs incurred and 2006 forecasted capital costs include exploration and production expenditures, capitalized general and administrative costs, capitalized interest costs and asset retirement costs.

(4) 2005 costs incurred includes proved property acquisitions of $3 million, $2 million and $49 million in the Permian, U.S. Offshore and Canada, respectively.

1999	2000	2001	2002	2003	2004	2005	5-Year Compound Growth Rate	10-Year Compound Growth Rate
439	406	527	444	661	596	649	10%	8%
2,785	3,045	5,024	5,836	7,316	7,494	7,296	19%	24%
55	50	108	192	209	232	246	38%	31%
958	963	1,472	1,609	2,089	2,077	2,112	17%	16%
5,316	17,075	6,687	15,307	22,652	23,428	35,610	16%	34%
25	37	36	42	62	78	64	12%	9%
295	417	489	761	863	891	827	15%	22%
5	7	8	19	22	24	24	26%	37%
79	113	126	188	228	251	226	15%	17%
17.78	24.99	21.41	21.71	25.63	28.18	38.44	9%	10%
2.09	3.53	3.84	2.80	4.51	5.32	6.99	15%	17%
13.28	20.87	16.99	14.05	18.65	23.04	28.96	7%	11%
14.22	22.38	22.19	17.61	25.88	29.88	39.59	12%	12%
4.15	4.81	5.29	4.71	5.63	6.13	7.43	9%	5%



unique /u•nique/ "They described an atmosphere that was challenging and rewarding and talked about how they looked forward to coming to work each day. I could tell Devon was unique because of the tone of the interview. They wanted to know about me and where I thought my career was going."

Kathryn Jenkins
Geologist
DEVON ENERGY CORPORATION

"As I was finishing my master's degree in geology at Louisiana State University, I wasn't sure I wanted a career in the energy industry. I had interviewed for internships with several energy companies but none of them inspired me to commit. Then I met the recruiters from Devon.

"They described an atmosphere that was challenging and rewarding and talked about how they looked forward to coming to work each day. I could tell Devon was unique because of the tone of the interview. They wanted to know about me and where I thought my career was going. I began a summer internship with the company in 2005 and eventually took a full-time position. Today, I'm with a group of veteran geologists, and mapping sandstone formations and exploring for natural gas in the Gulf of Mexico.

"Most people my age aren't fortunate enough to start out with their dream job. I feel like the luckiest person in the world because I never thought you could get a job that was this much fun."

PERMIAN

A / Southeast New Mexico

Profile
- 75% average working interest in 520,000 acres.
- Key fields include Ingle Wells, Catclaw Draw, West Red Lake, Gaucho and Outland.
- Produces oil and gas from multiple formations at 1,500' to 16,500'.
- 47.7 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled and completed 25 gas wells.
- Drilled and completed 38 oil wells.
- Recompleted 67 wells.
- Divested non-core properties.

2006 Plans
- Drill 22 gas wells.
- Drill 30 oil wells.
- Recomplete 48 wells.

B / West Texas

Profile
- 40% average working interest in 1.1 million acres.
- Key fields include Wasson, Reeves and Anton-Irish to the north; Ozona, Keystone/Kermit and Waddell to the south.
- Produces oil and gas from multiple formations at 2,500' to 18,000'.
- 113.8 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled and completed 14 gas wells.
- Drilled and completed 18 oil wells.
- Drilled 5 waterflood injection wells.
- Recompleted 52 wells.
- Reactivated 55 wells.
- Divested non-core properties.

2006 Plans
- Drill 8 gas wells.
- Drill 16 oil wells.
- Recomplete/reactivate 94 wells.

MID-CONTINENT

A / Arkoma Shale

Profile
- Working interests range from 50% to 80%.
- 78,000 net acres in eastern Oklahoma.
- Emerging unconventional natural gas play.
- Produces gas from the Woodford and Caney shale formations at 4,000' to 10,000'.
- 1.2 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled 10 Woodford wells, including:
  4 vertical wells.
  6 horizontal wells.
- Initiated drilling of 5 vertical Caney wells.
- Acquired additional acreage.
- Divested non-core acreage.

2006 Plans
- Drill 24 horizontal Woodford wells.
- Drill 12 horizontal Caney wells.
- Acquire additional 3-D seismic and acreage.

B / Barnett Shale

Profile
- 552,000 net acres (120,000 within core area) in the Fort Worth Basin of north Texas.
- 95% average working interest in core.
- >80% average working interest outside core.
- Produces gas from the Barnett Shale formation at 6,500' to 8,500'.
- 407.8 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled 128 wells within core area, including:
  69 vertical infill wells.
  59 horizontal wells.
- Drilled 89 wells outside core area, including:
  4 vertical wells.
  85 horizontal wells.
- Initiated 20-acre horizontal infill program in core area.
- Acquired 3-D seismic and acreage.

2006 Plans
- Drill 182 wells within core area, including:
  56 vertical infill wells.
  126 horizontal wells.
- Drill 140 horizontal wells outside core area.
- Continue 20-acre infill program.
- Acquire additional 3-D seismic and acreage.
- Expand gas gathering system in Johnson County.

ROCKY MOUNTAINS

A / Bear Paw

Profile
- 734,000 net acres in north central Montana.
- 90% average working interest in federal units.
- 75% average working interest outside federal units.
- Produces gas from the Eagle formation at 800' to 2,000'.
- 20.6 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled and completed 47 wells.
- Performed 75-well workover program.

2006 Plans
- Drill 71 wells, including 6 exploratory wells.
- Continue workover program.
- Add compression and evaluate other gas gathering system improvements.

B / Powder River Coalbed Natural Gas

Profile
- 75% average working interest in 346,000 acres in north eastern Wyoming.
- Produces coalbed natural gas from the Fort Union Coal formations at 300' to 2,000'.
- 16.7 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled 129 coalbed natural gas wells.
- Deepened 50 wells.
- Performed 109-well workover program.
- Recompleted 36 wells.
- Restimulated 40 wells.
- Installed compression for 280 wells.
- Initiated development of West Pine Tree and West Rough Draw Units.

2006 Plans
- Drill 248 coalbed natural gas wells.
- Deepen 16 wells.
- Install additional compression as needed.

C / Washakie

Profile
- 76% average working interest in 210,000 acres in southern Wyoming.
- Produces gas from multiple formations at 6,800' to 10,300'.
- 94.2 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled and completed 88 wells.
- Recompleted 12 wells.
- Installed 75 plunger lifts.

2006 Plans
- Drill 80 to 100 wells, including 7 directional wells.
- Install 100 plunger lifts.
- Add compression to increase gas gathering system capacity.

D / NEBU/32-9 Units

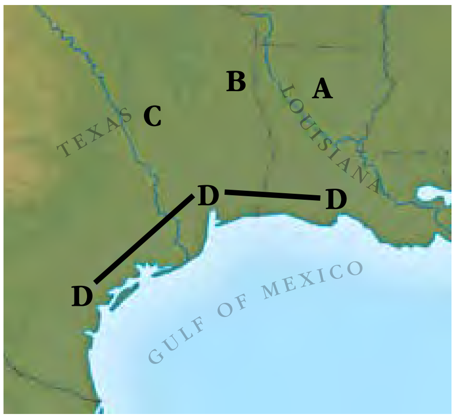
Profile
- 25% average working interest in 54,000 acres in the San Juan Basin of northwestern New Mexico.
- Coalbed natural gas development began in the late 1980s and early 1990s.

Key Property Highlights

- Includes 261 coalbed gas wells, 297 conventional wells, gas and water gathering systems and an automated production control system.
- Produces primarily coalbed natural gas from the Fruitland Coal formation at 3,000’.
- 19.7 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled and completed 28 coalbed gas wells.
- Completed 93-well workover program.
- Drilled and completed 25 conventional gas wells.
- Recompleted 8 conventional wells.
- Modified coalbed gas gathering system to accept conventional gas.

2006 Plans
- Drill 31 coalbed gas wells.
- Initiate 100-well workover program.
- Drill 29 conventional gas wells.
- Recomplete 11 conventional wells.



GULF COAST

A / North Louisiana Bossier

Profile
- 65% average working interest in 272,000 acres in north Louisiana.
- Hold mineral interests in 153,000 net acres.
- Emerging gas exploration play with 7 prospect areas identified, including Vixen, North Vixen and East Vernon.
- Produces from the lower Cotton Valley and Bossier formations at 13,000’ to 17,000’.
- Includes 28 producing wells.
- 6.6 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled 1 exploration discovery well at Vixen.
- Initiated drilling of 3 appraisal wells at Vixen.
- Drilled 1 exploration well at North Vixen.
- Acquired 3-D seismic at East Vernon.
- Initiated drilling 1 exploration well at East Vernon.
- Acquired additional acreage.

2006 Plans
- Drill delineation wells at Vixen.
- Acquire 3-D seismic at Vixen.
- Drill 3 exploration wells to test other prospect areas.

B / Carthage Area

Profile
- 85% average working interest in 171,000 acres in east Texas.
- Key fields include Carthage, Bethany, Waskom, Stockman and Appleby.
- Produces from the Pettit, Travis Peak and Cotton Valley formations at 5,700’ to 9,600’.
- Includes 1,400 producing wells.
- 141.6 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled and completed 121 wells.
- Recompleted 82 wells.
- Acquired additional acreage.
- Expanded gas gathering system capacity.

2006 Plans
- Drill 139 wells.
- Recomplete 50 wells.
- Initiate 20-acre infill pilot program.
- Expand gas gathering system capacity and salt water disposal facilities.
- Acquire additional acreage.

C / Groesbeck Area

Profile
- 72% average working interest in 201,000 acres in east central Texas.
- Key fields include Personville, Nan-Su-Gail, Dew and Bald Prairie.
- Produces from the Travis Peak, Cotton Valley, Bossier and Haynesville formations at 6,000’ to 13,000’.
- Includes 561 producing wells.
- 39.7 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled and completed 62 wells.
- Recompleted 13 wells.

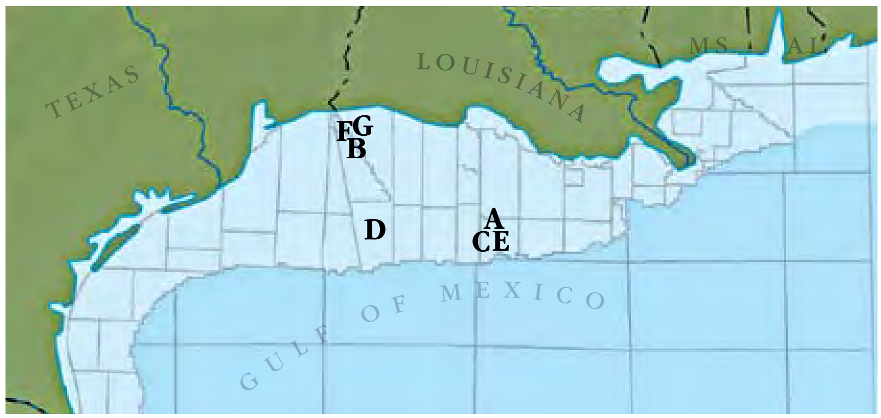
2006 Plans
- Drill 31 wells.
- Recomplete 11 wells.

D / South Texas/South Louisiana

Profile
- 66% average working interest in 619,000 acres.
- Key areas include Matagorda, Zapata, Agua Dulce/N. Brayton, Duval/Hagist, Houston, Central Texas and the Patterson field in Louisiana.
- Produces oil and gas from the Frio/Vicksburg, Yegua, Wilcox and Woodbine trends at 1,500’ to 15,000’.
- 30.5 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled and completed 34 wells.
- Recompleted 73 wells.
- Divested non-core properties.

2006 Plans
- Drill 37 wells.
- Recomplete 64 wells.
- Acquire additional acreage and seismic.



GULF - SHELF

A / Eugene Island South Area

Profile
- Includes 10 blocks located in and around the southern portion of Eugene Island area.
- Working interests range from 14% to 100%.
- Located offshore Louisiana in 250’ of water.
- Produces oil and gas from sands at 1,500’ to 13,000’.
- 8.7 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled Chopin discovery at Eugene Island 334.
- Completed 8-well recompletion program at Eugene Island 330C.
- Production shut-in due to hurricane damage.

2006 Plans
- Drill 5 wells at Eugene Island 315/316.
- Drill Barber exploration well (details follow).
- Drill Mercury exploration well (details follow).
- Initiate production from Chopin discovery.
- Restore shut-in production.

Shelf Exploration Prospects

Profile

B / Baltic
- West Cameron 291.
- Located offshore Louisiana in 50’ of water.
- Target formation: Miocene sands at 13,000’ to 14,000’.
- 60% working interest.
- Net unrisked reserve potential: 4 million barrels of oil equivalent.

C / Barber
- Eugene Island 334.
- Located offshore Louisiana in 250’ of water.
- Target formation: lower Pleistocene sands at 15,000’ to 16,000’.
- 67% working interest.
- Net unrisked reserve potential: 4 million barrels of oil equivalent.

D / Mamba
- West Cameron 537.
- Located offshore Louisiana in 175’ of water.
- Target formation: Miocene sands at 10,000’ to 13,000’.
- 100% working interest.
- Net unrisked reserve potential: undisclosed.

E / Mercury
- Eugene Island 337.
- Located offshore Louisiana in 270’ of water.
- Target formation: lower Pliocene sands at 6,000’ to 12,500’.
- 50% working interest.
- Net unrisked reserve potential: 2 million barrels of oil equivalent.

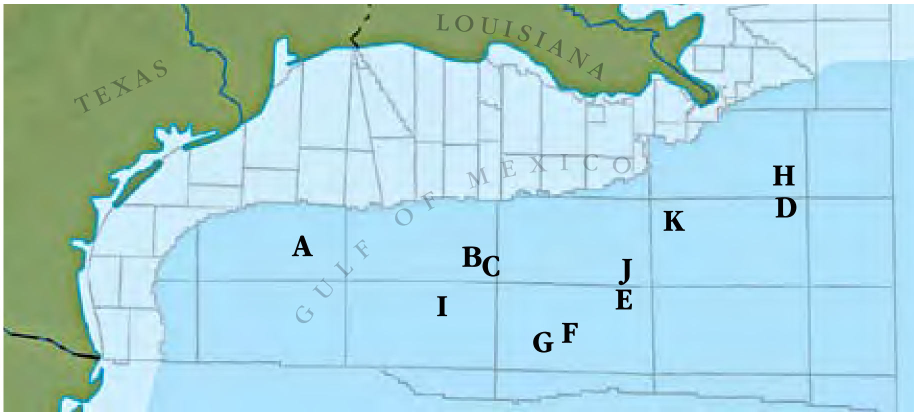
F / Star III
- West Cameron 164.
- Located offshore Louisiana in 50’ of water.
- Target formation: lower Miocene sands at 13,000’ to 14,500’.
- 100% working interest.
- Net unrisked reserve potential: 5 million barrels of oil equivalent.

G / Star V
- West Cameron 165.
- Located offshore Louisiana in 50’ of water.
- Target formation: lower Miocene sands at 12,000’ to 14,000’.
- 100% working interest.
- Net unrisked reserve potential: 10 million barrels of oil equivalent.

2005 Activity
- Finalized geophysical analysis and drilling contracts.
- Secured farmout agreements with industry partners.

2006 Plans
- Drill exploratory test wells.

Key Property Highlights



GULF - DEEPWATER

A / Nansen

Profile
- Includes 3 blocks in central East Breaks area.
- 50% working interest.
- Located offshore Texas in 3,500' of water.
- Produces oil and gas from sands at 9,000' to 14,000'.
- Utilizes the world's first open-hull truss spar.
- 44.1 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Completed 4-well recompletion program.
- Drilled 1 development well.
- Divested adjacent Boomvang field complex.

2006 Plans
- Evaluate potential for additional drilling.

B / Magnolia

Profile
- 25% working interest in Garden Banks 783 and 784.
- Located offshore Louisiana in 4,700' of water.
- Developing 1999 discovery.
- Produces oil and gas from sands at 12,000' to 17,000'.
- Utilizes the world's deepest tension-leg platform.
- 19.4 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Completed 5 wells.

2006 Plans
- Complete remaining 2 wells.
- Perform recompletions and sidetrack drilling as necessary.
- Evaluate potential for additional drilling.

C / Red Hawk

Profile
- 50% working interest in Garden Banks 876, 877, 920 and 921.
- Located offshore Louisiana in 5,300' of water.
- 2001 discovery.
- Produces gas from sands at 16,000' to 18,500'.
- Utilizes the world's first cell spar.
- 5.5 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Production shut-in due to hurricane damage to third-party downstream facilities in third quarter.

2006 Plans
- Restore shut-in production.
- Evaluate potential for additional drilling.

D / Merganser (Independence Hub)

Profile
- 50% working interest in Atwater Valley 37.
- Located offshore Louisiana in 8,100' of water.
- Developing 2001 discovery.
- To produce gas from sands at 19,000' to 20,000'.
- Production dedicated to Independence Hub.
- 9 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Initiated construction of surface and subsea facilities.
- Rig delays deferred drilling into 2006.

2006 Plans
- Sidetrack and complete 2 wells.
- Finish construction and installation of surface and subsea facilities.

Lower Tertiary Discoveries

Profile

E / Cascade
- 25% working interest in Walker Ridge 206.
- Located offshore Louisiana in 8,200' of water.
- Target formation: lower Tertiary sands at 25,000' to 27,000'.
- Discovery well drilled in 2002, encountering > 450' of net oil pay.

F / St. Malo
- 22.5% working interest in Walker Ridge 678.
- Located offshore Louisiana in 6,900' of water.
- Target formation: lower Tertiary sands at 26,000' to 29,000'.
- Discovery well drilled in 2003, encountering > 450' of net oil pay.

G / Jack
- 25% working interest in Walker Ridge 759.
- Located offshore Louisiana in 7,000' of water.
- Target formation: lower Tertiary sands.
- Discovery well drilled in 2004, encountering > 350' of net oil pay.

2005 Activity
- Drilled successful appraisal well and sidetrack at Cascade.
- Drilled successful appraisal well at Jack.
- Appraisal drilling at St. Malo deferred due to rig availability.

2006 Plans
- Conduct extended production test at Jack.
- Evaluate development options at Jack, Cascade and St. Malo.

Deepwater Exploration Prospects

Profile

H / Caterpillar
- 25% working interest in Mississippi Canyon 782.
- Located offshore Louisiana in 6,600' of water.
- Target formation: Miocene sands.
- Expected total depth: 28,000'.

I / Kaskida
- 20% working interest to be earned in Keathley Canyon 292.
- Located offshore Louisiana in 5,900' of water.

J / Mission Deep
- 50% working interest in Green Canyon 955.
- Located offshore Louisiana in 7,300' of water.
- Target formation: Miocene sands.
- Expected total depth: 26,500'.

K / Sturgis North
- 25% working interest in Atwater Valley 138.
- Located offshore Louisiana in 3,700' of water.
- Drilled 2003 oil discovery at Sturgis South.
- Expected total depth: 30,000'.

2005 Activity
- Finalized technical evaluations and drilling contracts.

2006 Plans
- Drill exploratory test wells.

CANADA

A / Mackenzie Delta/Beaufort Sea

Profile
- 48% average working interest in 2.8 million exploratory acres in the Mackenzie Delta and shallow waters of the Beaufort Sea.
- Devon is the largest holder of exploration acreage in this area.
- Drilling limited to winter only.
- 2002 Tuk M-18 discovery estimated at 200-300 billion cubic feet gross.

2005 Activity
- Refurbished steel drilling caisson used to drill the Paktoa prospect.
- Initiated exploratory drilling at Paktoa in the Beaufort Sea.

2006 Plans
- Complete exploratory drilling at Paktoa.
- Evaluate potential for future drilling in the Mackenzie Valley Pipeline corridor.

B / Northeast British Columbia

Profile
- 71% average working interest in 1.8 million acres in northwestern Alberta and northeastern British Columbia.
- Key areas include Hamburg, Peggo/Pesh/Tooga, Ring Border and Wargen.
- Primarily winter-only drilling.
- Produces oil and gas from multiple formations including liquid-rich gas from the Slave Point at 5,000' to 9,000'.
- 66.3 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Completed 117 of 125 wells drilled, including:
  - 32 wells at Ring Border.
  - 22 wells at Wargen.
  - 20 wells at Peggo.
  - 14 wells at Hamburg/Chinchaga.
- Divested non-core properties.

2006 Plans
- Drill 90 total wells, including:
  - 36 wells at Ring Border.
  - 19 wells at Wargen.
  - 10 wells at Peggo/Pesh/Tooga.
  - 8 wells at Hamburg/Chinchaga.

C / Peace River Arch

Profile
- 70% average working interest in 679,000 acres in western Alberta.
- Key areas include Belloy, Cecil, Dunvegan, Eaglesham, Knopcik, Tangent and Valhalla.
- Produces liquids-rich gas and light gravity oil from multiple formations at 4,500' to 8,000'.
- 80.9 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Completed 102 of 104 wells drilled, including:
  - 39 wells at Dunvegan.
  - 20 wells at Belloy.
  - 11 wells at Knopcik.
  - 11 wells at Cecil.
- Divested non-core properties.

2006 Plans
- Drill 48 total wells, including:
  - 13 wells at Cecil.
  - 13 wells at Belloy.
  - 11 wells at Valhalla.

D / Deep Basin

Profile
- 46% average working interest in 1.4 million acres in western Alberta and eastern British Columbia.
- Key areas include Bilbo, Elmworth, Leland, Pinto, Wapiti and Wapiti North.
- Produces liquids rich gas from primarily Cretaceous formations at 2,500' to 14,000'.
- 107.2 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Completed 160 of 179 wells drilled, including:
  - 39 wells at Wapiti.
  - 37 wells at Elmworth.
  - 31 wells at Bilbo.
  - 19 wells at Pinto.
  - 10 wells at Leland.
- Added compression at Pinto.

2006 Plans
- Drill 175 total wells, including:
  - 35 wells at Wapiti.
  - 33 wells at Bilbo.
  - 33 wells at Elmworth.
  - 24 wells at Leland.
  - 20 wells at Pinto.
  - 10 wells at Wapiti North.

E / Lloydminster

Profile
- 97% working interest in 2.2 million acres in eastern Alberta and Saskatchewan.
- Key areas include End Lake, Iron River, Lloydminster and Manatokan.
- Produces primarily conventional, cold flow heavy oil from multiple formations at 1,000' to 2,300'.
- 73.6 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Completed 236 of 237 wells drilled, including:
  - 67 wells at Manatokan.
  - 61 wells at Lloydminster.
  - 57 wells at Iron River.
  - 41 wells at End Lake.
- Acquired Iron River property, including 165,000 net acres with more than 800 drilling locations.

2006 Plans
- Drill 392 total wells, including:
  - 232 wells at Iron River.
  - 50 wells at Manatokan.
  - 50 wells at End Lake.
  - 42 wells at Lloydminster.

F / Thermal Heavy Oil

Profile
- 97% average working interest in 82,000 acres in eastern Alberta oil sands.
- Key asset is Jackfish (100% interest).
- Steam-Assisted Gravity Drainage (SAGD) is the primary recovery method.
- Expect 35,000 barrels per day from Jackfish in 2008.
- 117.6 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled 7 horizontal well pairs at Jackfish.
- Initiated construction on Jackfish facilities.
- Drilled 42 stratigraphic wells to evaluate Jackfish 2 potential.
- Acquired additional acreage at Jackfish 2.
- Received regulatory approval for Access Pipelines and began right-of-way clearing.
- Divested non-core properties.

2006 Plans
- Drill 17 additional horizontal well pairs at Jackfish.
- Continue construction on Jackfish facilities.
- Drill 30-45 stratigraphic wells to further evaluate Jackfish 2 potential.
- Initiate construction of Access Pipelines to and from Edmonton.

INTERNATIONAL

A / Azerbaijan – ACG

Profile
- 5.6% carried interest in 137,000 acres in the Azeri-Chirag-Gunashli (ACG) oil fields offshore Azerbaijan.
- Operating and capital cost paid by partners under carried interest agreement, payout expected in the first half of 2007.
- Initial position obtained in 1999 merger.
- Major oil export pipeline to be completed and commissioned in 2006.
- Expect >30,000 barrels per day net to Devon in 2007.
- 85.8 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Completed 8 pre-drilled wells from the Central Azeri platform.
- Installed West Azeri platform and production facilities.
- Completed 1 pre-drilled well from the West Azeri platform.
- Pre-drilled 4 wells for future production from the East Azeri platform.
- Drilled and completed 2 wells from the Chirag platform.
- Initiated drilling in the deepwater Guneshli area.

2006 Plans
- Commence compression and water injection operations in the Central Azeri field.
- Drill 5 wells from the Central Azeri platform.
- Drill 6 wells from the West Azeri platform.
- Continue construction and installation of East Azeri platform and production facilities.
- Drill 4 wells from the Chirag platform.

B / Brazil – Polvo

Profile
- 60% working interest in 17,400 acres in block BM-C-8 offshore Brazil.
- Located in the Campos Basin in 340' of water.
- Developing 2004 discovery.
- To produce oil from formations at 6,500' to 7,500'.
- First production expected in 2007.
- 50 million barrel project with additional resource potential.

2005 Activity
- Drilled and flow tested successful appraisal well.
- Received regulatory approval for Polvo development plan.
- Initiated fabrication of production jacket and drilling platform.
- Initiated refurbishment of platform drilling rig.
- Initiated FPSO conversion.

2006 Plans
- Continue fabrication of platform and refurbishment of drilling rig.
- Continue conversion of FPSO.

C / China

Profile
- 2.4 million acres in 2 licensed blocks in the South China Sea offshore China:
  - Block 15/34 (Panyu); 24.5% interest.
  - Block 42/05; 100% interest.
- Located in the Pearl River Mouth Basin in water depths ranging from 300' to 6,500'.
- Panyu fields produce oil from 1998 and 1999 discoveries.
- 15.5 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled and completed 5 development wells at Panyu.
- Drilled 2 unsuccessful exploratory test wells at Panyu.
- Initiated project to expand water handling capacity at Panyu.
- Acquired exploration block 42/05.

2006 Plans
- Complete development drilling initiated in 2005 at Panyu.
- Drill 1 extended reach development well at Panyu.
- Complete installation of water handling facilities on each platform at Panyu.
- Acquire Yellow Sea block 11/34.
- Acquire 3-D seismic on block 42/05.

D / Equatorial Guinea – Zafiro

Profile
- 23.75% working interest in 35,800 acres in the Zafiro field in block B offshore Equatorial Guinea (E.G.).
- Field facilities include one fixed production platform and two floating production vessels in 500' to 2,500' of water.
- Contains 62 producing wells and 23 water injection wells and 1 gas injection well.
- Produces oil from a complex system of reservoir channels at 5,000' to 6,000'.
- 77.5 million barrels of oil equivalent reserves at 12/31/05.

2005 Activity
- Drilled and completed 6 producing wells.
- Drilled and completed 2 water injection wells.
- Completed facility upgrades to allow more efficient transfer and storage of oil.
- Purchased the Serpentina FPSO (formerly leased).

2006 Plans
- Drill 9 development wells.
- Drill 2 water injection wells.
- Upgrade FPSO and platform facilities.
- Reprocess and evaluate 3-D seismic to identify future drilling locations.

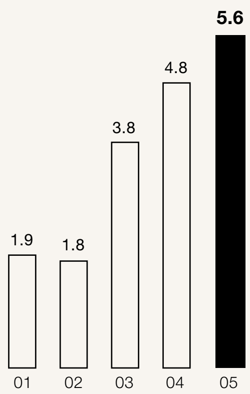
E / South Atlantic Margin Exploration

Profile
- 7.8 million acres in 8 licensed blocks offshore West Africa.
- 666,000 acres in 5 licensed blocks offshore Brazil.

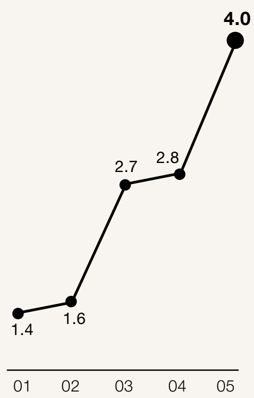
2005 Activity
- Drilled Esmeralda discovery well on block B in E.G.
- Drilled 1 unsuccessful exploratory well on block N in E.G.
- Drilled Venus discovery well on block P in E.G.
- Drilled 1 unsuccessful exploratory well on block 256 in Nigeria.
- Completed farmout agreements with industry partners on block 242 in Nigeria.
- Acquired 3-D seismic on block 242 in Nigeria.

2006 Plans
- Reprocess 3-D seismic on block B in E.G.
- Drill 2 appraisal wells and 1 exploratory well on block P in E.G.
- Finalize acquisition of interest in Gryphon Marin block in Gabon.
- Acquire 3-D seismic on Gryphon Marin block in Gabon.
- Reprocess 3-D seismic on Keta block in Ghana.
- Drill 1 exploratory well on block 256 in Nigeria.
- Drill 1 appraisal well and 2 exploratory wells on block BM-C-8 in Brazil.
- Drill 1 exploratory well on block BM-C-30 in Brazil.
- Drill 1 exploratory well on block BM-C-32 in Brazil.
- Farmout partial interests with industry partners on the Keta block in Ghana and block BM-BAR-3 in Brazil.
- Finalize acquisition of offshore blocks in Brazil.

NET CASH PROVIDED BY OPERATING ACTIVITIES
($ Billions)

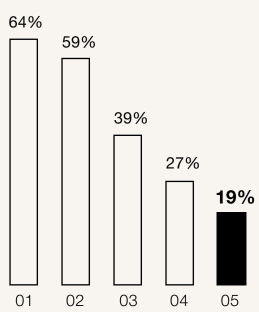


DRILL BIT CAPITAL*
($ Billions)



*A reconciliation to a GAAP measure is provided on page 98.

NET DEBT TO ADJUSTED CAPITALIZATION*
(As of December 31)



*A reconciliation to a GAAP measure is provided on page 98.

Cash flow from operations climbed to $5.6 billion in 2005, enabling Devon to invest $4 billion in exploration and development projects and repay $1.3 billion in long-term debt, reducing net debt to less than 20% of adjusted capital.

Selected Eleven-Year Financial Data [1]

		1995	1996	1997	1998
Operating Results *(In millions, except per share data)*					
Revenues *(Net of royalties)*:					
Oil sales	$	419	529	497	236
Gas sales		157	211	367	335
NGL sales		15	29	36	25
Marketing and midstream revenues		—	—	10	8
Other income		35	36	42	22
Total revenues		626	805	952	626
Production and operating expenses		222	271	288	231
Marketing and midstream costs and expenses		—	—	4	3
Depreciation, depletion and amortization of property and equipment		160	175	268	212
Accretion of asset retirement obligation		—	—	—	—
Amortization of goodwill [2]		—	—	—	—
General and administrative expenses		43	57	56	48
Expenses related to mergers		—	—	—	13
Interest expense [3]		39	59	51	53
Effects of changes in foreign currency exchange rates		—	—	6	16
Change in fair value of derivative financial instruments		—	—	—	—
Reduction of carrying value of oil and gas properties		97	—	633	354
Impairment of Chevron Corporation common stock		—	—	—	—
Income tax expense (benefit)		19	106	(128)	(103)
Total expenses		580	668	1,178	827
Net earnings (loss) before minority interest, cumulative effect of change in accounting principle and discontinued operations [4]		46	137	(226)	(201)
Net earnings (loss)		55	151	(218)	(236)
Preferred stock dividends		15	47	12	—
Net earnings (loss) to common stockholders	$	40	104	(230)	(236)
Net earnings (loss) per common share:					
Basic	$	0.38	0.98	(1.67)	(1.66)
Diluted	$	0.38	0.96	(1.67)	(1.66)
Weighted average shares outstanding:					
Basic		105	105	137	142
Diluted		105	111	151	154
Balance Sheet Data *(In millions)*					
Total assets	$	1,639	2,242	1,965	1,931
Debentures exchangeable into shares of Chevron Corporation common stock [5]	$	—	—	—	—
Other long-term debt [6]	$	565	511	576	885
Deferred income taxes	$	48	136	50	15
Stockholders' equity	$	739	1,160	1,006	750
Common shares outstanding		105	126	142	142

(1) All of the years shown exclude results from Devon's operations in Indonesia, Argentina and Egypt that were discontinued in 2002. Subsequent to the sale of its Egyptian and Indonesian operations, Devon acquired new Egyptian and Indonesian assets in the April 2003 Ocean merger. Amounts and activities related to these new Egyptian and Indonesian operations are included in Devon's continuing operations since 2003. All periods have been adjusted to reflect the two-for-one stock split that occurred on November 15, 2004.
(2) Amortization of goodwill in 1999, 2000 and 2001 resulted from Devon's 1999 acquisition of PennzEnergy. As of January 1, 2002, goodwill is no longer amortized.
(3) Includes distributions on preferred securities of subsidiary trust of $5, $10, $10 and $7 million in 1996, 1997, 1998 and 1999, respectively.
(4) Before minority interest in Monterrey Resources, Inc. of ($1) and ($5) million in 1996 and 1997, respectively, and the cumulative effect of change in accounting principle of $49 and $16 million in 2001 and 2003, respectively, and the results of discontinued operations of $9, $15, $13, ($35) $39, $69, $31 and $45 million in 1995 through 2002, respectively.
(5) Devon beneficially owns 14.2 million shares of Chevron Corporation common stock. These shares have been deposited with an exchange agent for possible exchange for $760 million principal amount of exchangeable debentures. The Chevron shares and debentures were acquired through the August 1999 merger with PennzEnergy.
(6) Includes preferred securities of subsidiary trust of $149 million in years 1996, 1997 and 1998.
N/M Not a meaningful number.

	1999	2000	2001	2002	2003	2004	2005	5-YEAR COMPOUND GROWTH RATE	10-YEAR COMPOUND GROWTH RATE
	436	906	784	909	1,588	2,202	2,478	22%	19%
	616	1,474	1,878	2,133	3,897	4,732	5,784	31%	43%
	68	154	131	275	407	554	687	35%	46%
	20	53	71	999	1,460	1,701	1,792	102%	N/M
	10	40	69	34	35	103	196	37%	19%
	1,150	2,627	2,933	4,350	7,387	9,292	10,937	33%	33%
	328	544	666	886	1,282	1,535	1,680	25%	22%
	10	28	47	808	1,174	1,339	1,342	117%	N/M
	379	662	831	1,211	1,793	2,290	2,191	27%	30%
	—	—	—	—	36	44	44	N/M	N/M
	16	41	34	—	—	—	—	N/M	N/M
	83	96	114	219	307	277	291	25%	21%
	17	60	1	—	7	—	—	N/M	N/M
	122	155	220	533	502	475	533	28%	30%
	(13)	3	11	(1)	(69)	(23)	(2)	N/M	N/M
	—	—	2	(28)	(1)	62	94	N/M	N/M
	476	—	979	651	111	—	212	N/M	8%
	—	—	—	205	—	—	—	N/M	N/M
	(75)	377	5	(193)	514	1,107	1,622	34%	56%
	1,343	1,966	2,910	4,291	5,656	7,106	8,007	32%	30%
	(193)	661	23	59	1,731	2,186	2,930	35%	51%
	(154)	730	103	104	1,747	2,186	2,930	32%	49%
	4	10	10	10	10	10	10	1%	-4%
	(158)	720	93	94	1,737	2,176	2,920	32%	54%
	(0.84)	2.83	0.37	0.31	4.16	4.51	6.38	18%	33%
	(0.84)	2.75	0.36	0.30	4.04	4.38	6.26	18%	32%
	187	255	255	309	417	482	458	12%	16%
	199	263	259	313	433	499	470	12%	16%
	6,096	6,860	13,184	16,225	27,162	30,025	30,273	35%	34%
	760	760	649	662	677	692	709	-1%	N/M
	1,656	1,289	5,940	6,900	7,903	6,339	5,248	32%	25%
	313	634	2,149	2,627	4,370	5,089	5,405	54%	60%
	2,521	3,277	3,259	4,653	11,056	13,674	14,862	35%	35%
	253	257	252	314	472	484	443	11%	15%

MD&A

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

OVERVIEW OF 2005 RESULTS AND OUTLOOK

2005 was the best year in our history. We continued to execute our strategy to increase value per share. As a result, we delivered record amounts for certain key measures of our financial and operating performance in 2005:

- Net earnings for the year climbed 34% to $2.9 billion
- Earnings per share climbed more than 40% to $6.26 per diluted share
- Net cash provided by operating activities reached $5.6 billion
- Estimated proved reserves at December 31, 2005 were 2.1 billion Boe
- Estimated proved reserves increased 439 million Boe through drilling, extensions and performance revisions
- Capital expenditures for oil and gas exploration and development activities were $3.9 billion
- Combined realized price for oil, gas and NGLs increased 32% to $39.59
- Marketing and midstream margin rose 25% to $450 million

We produced 226 million Boe in 2005, representing a 10% decrease compared to 2004. Excluding the effects of production lost due to the sale of non-core properties in the first half of 2005 and production suspended due to hurricanes in the last half of 2005, our year-over-year production increased 1%. In addition, with the significant increase in commodity prices and the weakened U.S. dollar compared to the Canadian dollar, operating costs also increased. Per unit lease operating expenses increased 17% to $5.95 per Boe.

In 2005, we utilized cash flow from operations and the proceeds from the sale of non-core properties to fund our $4.1 billion in capital expenditures, repay $1.3 billion in debt and repurchase $2.3 billion of our common stock. In August 2005, we announced a plan to repurchase up to 50 million additional shares of our common stock by the end of 2007. As of February 28, 2006, we had repurchased 4.4 million shares under this program.

We have laid the foundation for continued growth in future years, at competitive unit-costs, that we expect will create additional value for our investors. In 2006, we expect to deliver reserve additions of 410 to 440 million Boe with related capital in the range of $4.6 to $4.8 billion. We expect production to remain relatively flat from 2005 to 2006 for our retained properties. However, we expect an 8% increase in 2007 production over 2006, reflecting the significant reserve additions in 2004 and 2005, and those expected in 2006.

RESULTS OF OPERATIONS

Revenues

Changes in oil, gas and NGL production, prices and revenues from 2003 to 2005 are shown in the following tables. (Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.)

	TOTAL				
	YEAR ENDED DECEMBER 31,				
	2005	2005 vs 2004 (2)	2004	2004 vs 2003 (2)	2003
PRODUCTION					
Oil (MMBbls)	64	-18%	78	+26%	62
Gas (Bcf)	827	-7%	891	+3%	863
NGLs (MMBbls)	24	-1%	24	+10%	22
Oil, gas and NGLs (MMBoe) (1)	226	-10%	251	+10%	228
AVERAGE PRICES					
Oil (per Bbl)	$ 38.44	+36%	28.18	+10%	25.63
Gas (per Mcf)	$ 6.99	+32%	5.32	+18%	4.51
NGLs (per Bbl)	$ 28.96	+26%	23.04	+24%	18.65
Oil, gas and NGLs (per Boe) (1)	$ 39.59	+32%	29.88	+15%	25.88
REVENUES ($ in millions)					
Oil	$ 2,478	+13%	2,202	+39%	1,588
Gas	5,784	+22%	4,732	+21%	3,897
NGLs	687	+24%	554	+36%	407
Oil, gas and NGLs	$ 8,949	+20%	7,488	+27%	5,892

DOMESTIC						
YEAR ENDED DECEMBER 31,						
		2005	2005 vs 2004 (2)	2004	2004 vs 2003 (2)	2003
PRODUCTION						
Oil (MMBbls)		25	-19%	31	+2%	31
Gas (Bcf)		555	-8%	602	+2%	589
NGLs (MMBbls)		18	-4%	19	+13%	17
Oil, gas and NGLs (MMBoe) (1)		136	-10%	151	+3%	146
AVERAGE PRICES						
Oil (per Bbl)	$	41.64	+35%	30.84	+12%	27.64
Gas (per Mcf)	$	7.08	+30%	5.43	+21%	4.50
NGLs (per Bbl)	$	26.68	+24%	21.47	+24%	17.31
Oil, gas and NGLs (per Boe) (1)	$	40.21	+31%	30.80	+18%	26.02
REVENUES ($ in millions)						
Oil	$	1,062	+9%	976	+13%	861
Gas		3,929	+20%	3,261	+23%	2,652
NGLs		484	+19%	405	+40%	289
Oil, gas and NGLs	$	5,475	+18%	4,642	+22%	3,802

CANADA						
YEAR ENDED DECEMBER 31,						
		2005	2005 vs 2004 (2)	2004	2004 vs 2003 (2)	2003
PRODUCTION						
Oil (MMBbls)		13	-5%	14	+3%	14
Gas (Bcf)		261	-6%	279	+4%	267
NGLs (MMBbls)		6	+8%	5	-1%	5
Oil, gas and NGLs (MMBoe) (1)		62	-5%	65	+4%	63
AVERAGE PRICES						
Oil (per Bbl)	$	26.88	+24%	21.60	-8%	23.54
Gas (per Mcf)	$	6.95	+35%	5.15	+13%	4.57
NGLs (per Bbl)	$	37.19	+27%	29.23	+27%	23.08
Oil, gas and NGLs (per Boe) (1)	$	38.17	+33%	28.80	+10%	26.25
REVENUES ($ in millions)						
Oil	$	353	+18%	299	-6%	318
Gas		1,814	+26%	1,437	+18%	1,222
NGLs		196	+38%	143	+25%	114
Oil, gas and NGLs	$	2,363	+26%	1,879	+14%	1,654

INTERNATIONAL						
YEAR ENDED DECEMBER 31,						
		2005	2005 vs 2004 (2)	2004	2004 vs 2003 (2)	2003
PRODUCTION						
Oil (MMBbls)		26	-21%	33	+88%	17
Gas (Bcf)		11	+6%	10	+52%	7
NGLs (MMBbls)		—	N/M	—	N/M	—
Oil, gas and NGLs (MMBoe) (1)		28	-19%	35	+86%	19
AVERAGE PRICES						
Oil (per Bbl)	$	41.16	+45%	28.40	+20%	23.64
Gas (per Mcf)	$	3.76	+13%	3.33	-4%	3.47
NGLs (per Bbl)	$	22.81	+8%	21.12	-2%	21.45
Oil, gas and NGLs (per Boe) (1)	$	39.76	+42%	27.92	+19%	23.45
REVENUES ($ in millions)						
Oil	$	1,063	+15%	927	+126%	409
Gas		41	+20%	34	+46%	23
NGLs		7	+12%	6	+68%	4
Oil, gas and NGLs	$	1,111	+15%	967	+122%	436

(1) Gas converted to oil at the ratio of 6Mcf:1Bbl. Natural gas liquids converted to oil at the ratio of 1Bbl:1Bbl.
(2) All percentage changes included in this table are based on actual figures and not the rounded figures included in this table.
N/M Not a meaningful number.

The average prices shown in the preceding tables include the effect of our oil and gas price hedging activities. Following is a comparison of our average prices with and without the effect of hedges for each of the last three years.

		WITH HEDGES			WITHOUT HEDGES		
		2005	2004	2003	2005	2004	2003
Oil (per Bbl)	$	38.44	28.18	25.63	48.49	35.99	27.67
Gas (per Mcf)	$	6.99	5.32	4.51	7.14	5.39	4.79
NGLs (per Bbl)	$	28.96	23.04	18.65	28.96	23.04	18.65
Oil, gas and NGLs (per Boe)	$	39.59	29.88	25.88	42.98	32.60	27.48

Oil Revenues

2005 vs. 2004 Oil revenues increased $276 million in 2005. Oil revenues increased $661 million due to a $10.26 increase in the average realized price of oil. A decrease in 2005 production of 14 million barrels caused oil revenues to decrease by $385 million. Production lost from the 2005 property divestitures accounted for seven million barrels of the decrease. We also suspended certain domestic oil production in 2005 and 2004 due to the effects of Hurricanes Katrina, Rita, Dennis and Ivan. The year over year impact accounted for an additional one million barrels of suspended production in 2005 than in 2004. The remainder of the decrease is due to certain international properties in which our ownership interest decreased after we recovered our costs under the applicable production sharing contracts.

2004 vs. 2003 Oil revenues increased $614 million in 2004. An increase in 2004 production of 16 million barrels caused oil revenues to increase by $415 million. The April 2003 Ocean merger accounted for 14 million barrels of increased production. The remaining increase is primarily related to new production from China partially offset by natural production declines and the effects of Hurricane Ivan on domestic properties in 2004. Oil revenues increased $199 million due to a $2.55 increase in the average realized price of oil.

Gas Revenues

2005 vs. 2004 Gas revenues increased $1.1 billion in 2005. A $1.67 per Mcf increase in the average realized gas price caused revenues to increase by $1.4 billion. A decrease in 2005 production of 64 Bcf caused gas revenues to decrease by $337 million. Production associated with the 2005 property divestitures caused a decrease of 89 Bcf. We also suspended certain domestic gas production in 2005 and 2004 due to the effects of Hurricanes Katrina, Rita, Dennis and Ivan. The year over year impact accounted for an additional 12 Bcf of suspended production in 2005 than in 2004. These decreases were more than offset by new drilling and development and increased performance in U.S. offshore and onshore properties.

2004 vs. 2003 Gas revenues increased $835 million in 2004. An $0.81 per Mcf increase in the average realized gas price caused revenues to increase by $714 million. An increase in 2004 production of 28 Bcf caused gas revenues to increase by $121 million. The April 2003 Ocean merger accounted for 43 Bcf of increased production. This was offset by a production decrease in domestic properties as a result of natural declines and the effects of Hurricane Ivan in 2004.

NGL Revenues

2005 vs. 2004 NGL revenues increased $133 million in 2005. A $5.92 per barrel increase in average NGL prices caused revenues to increase by $141 million. A slight decrease in 2005 production due to 2005 property divestitures and suspended production in 2005 due to Hurricanes Katrina, Rita and Dennis caused revenues to decrease by $8 million.

2004 vs. 2003 NGL revenues increased $147 million in 2004. A $4.39 per barrel increase in average NGL prices caused revenues to increase by $106 million. An increase in 2004 production of 2 million barrels caused revenues to increase $41 million. The April 2003 Ocean merger accounted for 0.6 million barrels of increased production. The remaining production increase was primarily related to new drilling and development in the Barnett Shale properties.

Marketing and Midstream Revenues

2005 vs. 2004 Marketing and midstream revenues increased $91 million in 2005. Of this increase, approximately $442 million was the result of higher overall market prices for natural gas and NGLs. This was partially offset by $338 million in lower revenues resulting primarily from the sale of certain assets in 2004 and 2005. Additionally, revenues decreased $13 million primarily due to lower third-party natural gas and NGL throughput volumes.

2004 vs. 2003 Marketing and midstream revenues increased $241 million in 2004. Of this increase, approximately $218 million was the result of higher overall market prices for natural gas and NGLs. Additionally, revenues increased $103 million due to higher third-party natural gas and NGL throughput volumes. This was partially offset by $80 million in lower revenues resulting primarily from the sale of certain assets in 2004.

Oil, Gas and NGL Production and Operating Expenses

The details of the changes in oil, gas and NGL production and operating expenses between 2003 and 2005 are shown in the table below.

		YEAR ENDED DECEMBER 31,				
		2005	2005 vs 2004 (1)	2004	2004 vs 2003 (1)	2003
EXPENSES ($ in millions):						
Production and operating expenses:						
Lease operating expenses	$	1,345	+5%	1,280	+19%	1,078
Production taxes		335	+31%	255	+25%	204
Total production and operating expenses	$	1,680	+9%	1,535	+19%	1,282
EXPENSES PER BOE:						
Production and operating expenses:						
Lease operating expenses	$	5.95	+17%	5.11	+8%	4.73
Production taxes		1.48	+45%	1.02	+13%	0.90
Total production and operating expenses	$	7.43	+21%	6.13	+9%	5.63

(1) All percentage changes included in this table are based on actual figures and not the rounded figures included in this table.

2005 vs. 2004 Lease operating expenses increased $65 million in 2005. The increase in lease operating expense was largely caused by higher commodity prices. With the increase in oil, gas and NGL prices, more well workovers and repairs and maintenance costs were performed to either maintain or improve production volumes. Other costs, including ad valorem taxes, power and fuel costs increased primarily as a result of higher commodity prices. Additionally, changes in the Canadian-to-U.S. dollar exchange rate resulted in a $30 million increase in costs. Partially offsetting these increases was a decrease of $144 million in lease operating expenses related to properties that were sold in 2005.

The increases described above were also the primary factors causing lease operating expenses per Boe to increase. Although we divested properties that had higher per-unit operating costs, the cost escalation largely related to higher commodity prices and the weaker U.S. dollar compared to the Canadian dollar had a greater effect on our per unit costs than the property divestitures.

Production taxes increased $80 million in 2005. The majority of our production taxes are assessed on our onshore domestic properties. In the U.S., most of the production taxes are based on a fixed percentage of revenues. Therefore, the 18% increase in domestic oil, gas and NGL revenues was the primary cause of the production tax increase. In addition, production taxes related to our international production increased $26 million due to higher export tax rates in Russia as well as higher revenue in China and Russia.

2004 vs. 2003 Lease operating expenses increased $202 million in 2004. The April 2003 Ocean merger accounted for $84 million of the increase. Lease operating expenses on our historical properties increased $88 million, due to an increase in well workover expenses, ad valorem taxes and power, fuel, casualty insurance and repairs and maintenance costs. Additionally, changes in the Canadian-to-U.S. dollar exchange rate resulted in a $30 million increase in costs.

The increase in lease operating expenses per Boe is primarily related to increased well workover expenses, ad valorem taxes and power, fuel and repairs and maintenance costs, as well as the changes in the Canadian-to-U.S. dollar exchange rate.

Production taxes increased $51 million in 2004. The 22% increase in domestic oil, gas and NGL revenues was the primary cause of the production tax increase.

Depreciation, Depletion and Amortization of Oil and Gas Properties ("DD&A")

DD&A of oil and gas properties is calculated by multiplying the percentage of total proved reserve volumes produced during the year by the "depletable base." The depletable base represents the net capitalized investment plus future development costs in those reserves. Generally, if reserve volumes are revised up or down, then the DD&A rate per unit of production will change inversely. However, if the depletable base changes, then the DD&A rate moves in the same direction. The per unit DD&A rate is not affected by production volumes. Absolute or total DD&A, as opposed to the rate per unit of production, generally moves in the same direction as production volumes. Oil and gas property DD&A is calculated separately on a country-by-country basis.

2005 vs. 2004 Oil and gas property related DD&A decreased $110 million in 2005. DD&A decreased $210 million due to a 10% decrease in the combined oil, gas and NGL production in 2005. This decrease was partially offset by an increase in the consolidated DD&A rate from $8.54 per BOE in 2004 to $8.99 per BOE in 2005 which caused oil and gas property related DD&A to increase by $100 million. In 2005, finding and development costs for reserve discoveries and extensions were lower than previous years but were higher than the 2004 DD&A rate of $8.54. This caused the 2005 rate to increase $0.49. With the higher commodity prices, current development costs and estimates of future development costs increased in 2005 compared to 2004. In addition, changes in the Canadian-to-U.S. dollar exchange rate caused the rate to increase $0.17. These increases were partially offset by a $0.21 decrease in the rate as a result of our 2005 property divestitures.

2004 vs. 2003 Oil and gas property related DD&A increased $473 million in 2004. An increase in the consolidated DD&A rate from $7.33 per BOE in 2003 to $8.54 per BOE in 2004 caused oil and gas property related DD&A to increase by $305 million. The increase in the DD&A rate is primarily related to the April 2003 Ocean merger, negative reserve revisions in Canada and certain international countries subject to production sharing contracts and changes in the Canadian-to-U.S. dollar exchange rate. A 10% increase in 2004 oil, gas and NGL production caused DD&A to increase $168 million.

Marketing and Midstream Operating Costs and Expenses

2005 vs. 2004 Marketing and midstream operating costs and expenses increased $3 million in 2005. Of this increase, approximately $306 million was the result of an increase in prices paid for natural gas and NGLs. This was partially offset by $297 million in lower costs and expenses resulting primarily from the sale of certain assets in 2004 and 2005. Additionally, operating costs and expenses decreased $6 million primarily due to lower third-party natural gas and NGL throughput volumes.

2004 vs. 2003 Marketing and midstream operating costs and expenses increased $165 million in 2004. Of this increase, approximately $133 million was the result of an increase in prices paid for natural gas and NGLs. Additionally, operating costs and expenses increased $106 million due to higher third-party natural gas and NGL throughput volumes. This was partially offset by $74 million in lower costs and expenses resulting primarily from the sale of certain assets in 2004.

General and Administrative Expenses ("G&A")

Our net G&A consists of three primary components. The largest of these components is the gross amount of expenses incurred for personnel costs, office expenses, professional fees and other G&A items. The gross amount of these expenses is partially reduced by two offsetting components. One is the amount of G&A capitalized pursuant to the full cost method of accounting related to exploration and development activities. The other is the amount of G&A reimbursed by working interest owners of properties for which we serve as the operator. These reimbursements are received during both the drilling and operational stages of a property's life. The gross amount of G&A incurred, less the amounts capitalized and reimbursed, is recorded as net G&A in the consolidated statements of operations. Net G&A includes expenses related to oil, gas and NGL exploration and production activities, as well as marketing and midstream activities. See the following table for a summary of G&A expenses by component.

	YEAR ENDED DECEMBER 31,				
	2005	2005 vs 2004	2004	2004 vs 2003	2003
			($ IN MILLIONS)		
Gross G&A	$ 584	+6%	549	+5%	524
Capitalized G&A	(189)	+10%	(172)	+22%	(140)
Reimbursed G&A	(104)	+4%	(100)	+29%	(77)
Net G&A	$ 291	+5%	277	-10%	307

2005 vs. 2004 Gross G&A increased $35 million. Higher employee compensation and benefits costs caused gross G&A to increase $38 million. Of this increase, $17 million related to higher restricted stock compensation primarily due to our December 2005 and 2004 grants. In addition, changes in the Canadian-to-U.S. dollar exchange rate caused an $9 million increase in costs. These increases were offset by an $8 million decrease in rent expense resulting primarily from the abandonment of certain Canadian office space in 2004.

The $17 million increase in capitalized G&A resulted primarily from the higher salaries and benefits related to oil and gas exploration and development capital projects. In addition, changes in the Canadian-to-U.S. dollar exchange rate caused capitalized G&A to increase $3 million.

2004 vs. 2003 Gross G&A increased $25 million. The April 2003 Ocean merger increased gross expenses $27 million primarily due to the inclusion of an additional four months of Ocean activities in 2004 compared to 2003. Also, higher compensation and benefit costs, increased charitable contributions and the abandonment of certain Canadian office space increased gross G&A $26 million, $12 million and $5 million, respectively. During 2004, we also incurred $6 million of incremental professional fees related to additional activities performed to comply with the requirements of Section 404 of The Sarbanes-Oxley Act of 2002. Finally, changes in the Canadian-to-U.S. dollar exchange rate resulted in an $8 million increase in costs. These increases were partially offset by the synergies obtained from the Ocean merger.

The increase in both capitalized G&A of $32 million and reimbursed G&A of $23 million was primarily related to the increased activity subsequent to the April 2003 Ocean merger.

Reduction of Carrying Value of Oil and Gas Properties

During 2005 and 2003, we reduced the carrying value of our oil and gas properties due to full cost ceiling limitations and unsuccessful exploratory activities. A detailed description of how full cost ceiling limitations are determined is included in the Critical Accounting Policies and Estimates section of this report. A summary of these reductions and additional discussion is provided below.

	YEAR ENDED DECEMBER 31,			
	2005		2003	
	GROSS	NET OF TAXES	GROSS	NET OF TAXES
	(IN MILLIONS)			
CEILING TEST REDUCTIONS:				
Egypt	$ —	—	45	26
Indonesia	—	—	4	1
Russia	—	—	19	9
UNSUCCESSFUL EXPLORATORY REDUCTIONS:				
Angola	170	119	—	—
Brazil	42	42	11	7
Ghana	—	—	26	26
Other	—	—	6	5
Total	$ 212	161	111	74

2005 Reductions Our interests in Angola were acquired through the Ocean Energy acquisition. Our drilling program has been unsuccessful in Angola, resulting in no proven reserves for the country. After drilling three unsuccessful wells in the fourth quarter of 2005, we determined that all of the Angolan capitalized costs should be impaired. Devon has a commitment to drill one additional well in Angola by the end of August 2006.

Prior to the fourth quarter of 2005, we were capitalizing the costs of previous unsuccessful efforts in Brazil pending the determination of whether proved reserves would be recorded in Brazil. We have been successful in our drilling efforts on block BM-C-8 in Brazil, and are currently developing our Polvo project on this block. The ultimate value of the Polvo project is expected to be in excess of the sum of its related costs, plus the costs of the previous unrelated unsuccessful efforts in Brazil which were capitalized. However, the Polvo proved reserves will be recorded over a period of time. It is expected that a small initial portion of the proved reserves ultimately expected at Polvo will be recorded in 2006. Based on preliminary estimates developed in the fourth quarter of 2005, the value of this initial partial booking of proved reserves will not be sufficient to offset the sum of the related proportionate Polvo costs plus the costs of the previous unrelated unsuccessful efforts. Therefore, we determined that the prior unsuccessful costs unrelated to the Polvo project should be impaired. These costs totaled approximately $42 million. There is no tax benefit related to the Brazilian impairment.

2003 Reductions The Egyptian reduction was primarily due to poor results of a development well that was unsuccessful in the primary objective. Partially as a result of this well, we revised Egyptian proved reserves downward. The Russian reduction was primarily the result of additional capital costs incurred as well as an increase in operating costs. The Indonesian reduction was primarily related to an increase in operating costs and a reduction in proved reserves.

Additionally, during 2003, we elected to discontinue certain exploratory activities in Ghana, certain properties in Brazil and other smaller concessions. After meeting the drilling and capital commitments on these properties, we determined that these properties did not meet our internal criteria to justify further investment. Accordingly, we recorded a charge associated with the impairment of these properties.

Interest Expense

The following schedule includes the components of interest expense between 2003 and 2005.

	2005	2004	2003
	(IN MILLIONS)		
Interest based on debt outstanding	$ 507	513	531
Accretion of debt discount, net	4	2	3
Facility and agency fees	2	2	1
Amortization of capitalized loan costs	7	22	12
Capitalized interest	(70)	(70)	(50)
Early retirement premiums	76	—	—
Other	7	6	5
Total interest expense	$ 533	475	502

2005 vs. 2004 The average debt balance decreased from $8.2 billion in 2004 to $7.4 billion in 2005 due to debt repayments during 2004 and 2005. This decrease in debt outstanding caused interest expense to decrease $53 million. This decrease in interest expense was partially offset by a $47 million increase due to higher floating rates in 2005. The average interest rate on outstanding debt increased from 6.3% in 2004 to 6.8% in 2005.

Other items included in interest expense that are not related to the debt balance outstanding were $64 million higher in 2005. Of this increase, $51 million related to the early retirement premium for the redemption of the $400 million 6.75% notes and $25 million related to the loss on the early redemption of the zero coupon convertible senior debentures. In conjunction with the early redemption of the senior debentures, we also expensed $5 million in remaining unamortized issuance costs. This was partially offset by $16 million of unamortized debt issuance costs that were expensed in the second quarter of 2004 upon the early repayment of the outstanding balance under our $3 billion term loan credit facility.

2004 vs. 2003 The average debt balance outstanding decreased from $8.6 billion in 2003 to $8.2 billion in 2004 causing interest expense to decrease $22 million. The decrease in average debt outstanding was due to debt repayments during 2004. The average interest rate on outstanding debt increased from 6.2% in 2003 to 6.3% in 2004. The higher rate in 2004 caused interest expense to increase $4 million.

Other items included in interest expense that are not related to the debt balance outstanding were $9 million lower in 2004. Of this decrease, $20 million related to the capitalization of interest. The increase in interest capitalized was primarily related to additional unproved properties acquired from the April 2003 Ocean Energy merger and the nature of the properties acquired. The Ocean properties included significant deepwater Gulf and international exploratory properties and major development projects. The effect of the $20 million increase in capitalized interest was partially offset by the $16 million of debt issuance costs that were expensed in 2004 as a result of the early repayment of the outstanding balance under our $3 billion term loan credit facility.

Effects of Changes in Foreign Currency Exchange Rates

Our Canadian subsidiary, which has designated the Canadian dollar as its functional currency, had $400 million 6.75% senior notes outstanding which were denominated in U.S. dollars. Changes in the exchange rate between the U.S. dollar and the Canadian dollar while the notes were outstanding increased or decreased the expected amount of Canadian dollars eventually required to repay the notes. In addition, our Canadian subsidiary has cash and other working capital amounts denominated in U.S. dollars which also fluctuate in value with changes in the exchange rate. Such changes in the Canadian dollar equivalent balance of the debt and working capital balances are required to be included in determining net earnings for the period in which the exchange rate changes.

The changes in the Canadian-to-U.S. dollar exchange rate from $0.8308 at December 31, 2004 to $0.8503 at the redemption date of the Canadian senior notes resulted in a gain of $9 million in 2005. Also in 2005, our Canadian subsidiary purchased U.S. dollars related to our repatriation of $535 million of earnings from our Canadian operations to the U.S. As a result of a decrease in the Canadian-to-U.S. dollar exchange rate while these U.S. dollars were held, we recognized a $7 million loss in 2005. The increase in the Canadian-to-U.S. dollar exchange rate from $0.7738 at December 31, 2003 to $0.8308 at December 31, 2004 resulted in a $22 million gain. The increase in the Canadian-to-U.S. dollar exchange rate from $0.6331 at December 31, 2002 to $0.7738 at December 31, 2003 resulted in a $69 million gain.

Change in Fair Value of Derivative Financial Instruments

The details of the changes in fair value of derivative financial instruments between 2003 and 2005 are shown in the table below.

	2005	2004	2003
		(IN MILLIONS)	
Change in fair value of the option embedded in debentures exchangeable into shares of Chevron Corporation common stock	$ 54	58	(3)
Ineffectiveness of commodity hedges	5	5	1
Non-qualifying commodity hedges	39	—	—
Other	(4)	(1)	1
Total	$ 94	62	(1)

The change in fair value of the option embedded in debentures exchangeable into shares of Chevron Corporation common stock decreased $4 million and increased $61 million in 2005 and 2004, respectively. The value of this option is driven primarily by the price of Chevron Corporation's common stock. Generally, as the price of Chevron Corporation's common stock increases, we recognize a larger loss on the option.

In 2005, we recognized a $39 million loss on certain oil derivative financial instruments that no longer qualified for hedge accounting because the hedged production exceeded actual and projected production under these contracts. The lower than expected production was caused primarily by hurricanes that affected offshore production in the Gulf of Mexico.

Other Income, Net

The following schedule includes the components of other income between 2003 and 2005.

	2005	2004	2003
		(IN MILLIONS)	
Interest and dividend income	$ 95	45	33
Gain on sales of non-oil and gas property and equipment	150	33	(3)
Loss on derivative financial instruments	(48)	—	—
Other	(1)	25	7
Total	$ 196	103	37

2005 vs. 2004 Other income increased $93 million in 2005. Other income increased $117 million due to gains resulting from sales of certain non-oil and gas properties in 2005. Interest and dividend income increased $50 million in 2005 primarily due to an increase in cash and short-term investment balances and higher interest rates. The 2005 loss on derivative financial instruments resulted primarily from a $55 million loss on certain commodity hedges that no longer qualified for hedge accounting and were settled prior to the end of their original term. These hedges related to U.S. and Canadian oil production from properties sold as part of our 2005 property divestiture program. This loss was partially offset by a $7 million gain related to interest rate swaps that were settled prior to the end of their original term in conjunction with the early redemption of the $400 million 6.75% senior notes in 2005.

2004 vs. 2003 Other income increased $66 million in 2004. Other income increased $36 million due to gains resulting from sales of certain non-oil and gas properties in 2004. Interest and dividend income increased $12 million in 2004 due to an increase in cash and short-term investment balances.

Income Taxes

2005 vs. 2004 Our 2005 effective financial tax rate was 36% compared to 34% in 2004. Both rates approximated the 35% statutory federal tax rate. Income taxes were reduced by $14 million and $36 million in 2005 and 2004, respectively, related to Canadian statutory rate reductions. The 2005 rate also included $28 million of additional tax related to our repatriation of $545 million, substantially all of which was Canadian earnings from our Canadian subsidiary, to the U.S.

2004 vs. 2003 Our 2004 effective financial tax rate attributable to continuing operations was 34% compared to 23% in 2003. Both years' rates were affected by the incremental effect of state income taxes offset by the tax benefits of certain foreign deductions. In addition, both the 2004 and 2003 rates included benefits from Canadian statutory rate reductions of $36 million and $218 million, respectively. Excluding the effect of the 2003 Canadian rate reduction, the 2003 effective tax rate would have been 33%.

Cumulative Effect of Change in Accounting Principle

Effective January 1, 2003, we adopted Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations*, and recorded a cumulative-effect-type adjustment for an increase to net earnings of $16 million net of deferred taxes of $10 million.

In September 2004, the SEC issued Staff Accounting Bulletin No. 106 ("SAB No. 106") to provide guidance regarding the interaction of SFAS No. 143 with the full cost method of accounting for oil and gas properties. Specifically, SAB No. 106 clarifies the manner in which the full cost ceiling test and DD&A should be calculated in accordance with the provisions of SFAS No. 143. We adopted SAB No. 106 in the fourth quarter of 2004. However, this adoption did not materially impact our full cost ceiling test calculation or DD&A for 2004.

CAPITAL RESOURCES, USES AND LIQUIDITY

The following discussion of capital resources, uses and liquidity should be read in conjunction with the consolidated financial statements included in this report.

Sources and Uses of Cash

At December 31, 2005, our unrestricted cash and cash equivalents and short-term investments totaled $2.3 billion. During 2005, 2004 and 2003, such balances increased $167 million, $846 million and $981 million, respectively. The following table summarizes the changes in our cash and cash equivalents from 2003 to 2005. Additional discussion of the key elements contributing to these changes follows the table.

		2005	2004	2003
			(IN MILLIONS)	
Cash provided by (used in):				
Operating activities	$	5,612	4,816	3,768
Investing activities		(1,652)	(3,634)	(2,773)
Financing activities		(3,543)	(1,001)	(414)
Effect of exchange rate changes		37	39	59
Net increase in cash and cash equivalents	$	454	220	640
Cash and cash equivalents at end of year	$	1,606	1,152	932
Short-term investments at end of year	$	680	967	341

Cash Flows from Operating Activities Net cash provided by operating activities ("operating cash flow") is our primary source of capital and liquidity. Operating cash flow is largely affected by our net earnings, excluding large non-cash expenses such as depreciation, depletion and amortization and deferred income tax expense. As a result, our operating cash flow increased in 2005 and 2004 compared to the previous years due to increases in net earnings, as discussed in the "Results of Operations" section of this report.

Cash Flows from Investing Activities *Capital Expenditures.* The increases in operating cash flow enabled us to invest larger amounts in capital projects. As a result, our capital expenditures increased 32% to $4.1 billion in 2005. The majority of this increase related to our expenditures for the acquisition, drilling or development of oil and gas properties, which totaled $3.9 billion in 2005. Increased drilling activities in the Barnett Shale, the approximately $200 million acquisition of Iron River acreage in Canada and the $74 million purchase of the Serpentina FPSO in offshore Equatorial Guinea were large contributors to the increase. Significant cost escalation and the weaker U.S. dollar also caused our expenditures to increase from 2004 to 2005.

Capital expenditures also increased 20% to $3.1 billion in 2004. Our April 2003 merger with Ocean Energy was the primary cause of this increase because 2003 only included eight months of capital activity related to the Ocean Energy properties acquired.

Proceeds from Sales of Property and Equipment. In 2005, we generated $2.2 billion in proceeds from sales. This consisted primarily of $2.0 billion in pre-tax proceeds, net of all purchase price adjustments, related to the sale of non-core oil and gas properties. In addition, we sold non-core midstream assets for $0.2 billion in pre-tax proceeds. Net of related income taxes, these proceeds were $1.8 billion for oil and gas properties and $0.1 billion for midstream assets.

Proceeds from the sale of property and equipment were $95 million and $179 million in 2004 and 2003, respectively. These amounts consisted primarily of proceeds related to the sale of non-core midstream assets.

Changes in Short-Term Investments. To maximize our income on available cash balances, we invest in highly liquid, short-term investments. The purchase and sale of these short-term investments will cause cash and cash equivalents to decrease and increase, respectively. Short-term investment balances decreased $287 million in 2005, increased $626 million in 2004 and increased $341 million in 2003.

Cash Flows from Financing Activities *Net Debt Repayments.* Our net debt retirements were $1.3 billion, $1.0 billion and $0.5 billion in 2005, 2004 and 2003, respectively. The 2005 amount includes $0.8 billion related to the retirement of the zero coupon convertible debentures and the $400 million 6.75% notes due March 2011 before their scheduled maturity dates. The 2004 amount includes $635 million for the payment of the outstanding balance under our $3 billion term loan credit facility. The 2003 amount includes payments on certain debt instruments assumed in the April 2003 Ocean Energy merger.

Stock Repurchases. We are utilizing operating cash flow and proceeds from the sale of non-core oil and gas properties to repurchase our common stock. In August 2005, we completed the stock repurchase program announced September 27, 2004. Under this program, we repurchased 44.6 million shares at a total cost of $2.1 billion in 2005, and 5.0 million shares at a total cost of $189 million in 2004. Subsequent to the completion of the program announced in 2004, we announced on August 3, 2005 a new program. Under this new program, we may repurchase up to 50 million shares by the end of 2007. In 2005, we purchased 2.2 million shares at a total cost of $134 million under this new repurchase program.

Dividends. Our common stock dividends were $136 million, $97 million and $39 million in 2005, 2004 and 2003, respectively. We also paid $10 million of preferred stock dividends in 2005, 2004 and 2003. The 2005 increase in common stock dividends was primarily related to a 50% increase in the dividend rate in the first quarter of 2005, partially offset by a decrease in outstanding shares due to share repurchases. The 2004 increase in common stock dividends resulted from a 100% increase in the dividend rate in the first quarter of 2004 and an increase in outstanding shares due to the April 2003 Ocean Energy merger.

Issuance of Common Stock. Proceeds from the issuance of our common stock were $124 million, $268 million and $155 million in 2005, 2004 and 2003, respectively. These proceeds were derived primarily from the exercise of employee stock options.

Liquidity

Historically, our primary source of capital and liquidity has been operating cash flow. Additionally, we maintain a revolving line of credit and a commercial paper program which can be accessed as needed to supplement operating cash flow. Other available sources of capital and liquidity include the issuance of equity securities and long-term debt. We expect the combination of these sources of capital will be more than adequate to fund future capital expenditures, common stock repurchases, and other contractual commitments as discussed later in this section.

Operating Cash Flow Our operating cash flow has increased nearly 50% since 2003, reaching a total of $5.6 billion in 2005. Our operating cash flow is sensitive to many variables, the most volatile of which is pricing of the oil, natural gas and NGLs produced. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict. We expect operating cash flow to continue to be our primary source of liquidity.

Credit Lines Another source of liquidity is our $1.5 billion five-year, syndicated, unsecured revolving line of credit (the "Senior Credit Facility"). The Senior Credit Facility includes (i) a five-year revolving Canadian subfacility in a maximum amount of U.S. $500 million and (ii) a $1 billion sublimit for the issuance of letters of credit, including letters of credit under the Canadian subfacility. Amounts borrowed under the Senior Credit Facility may, at our election, bear interest at various fixed rate options for periods of up to twelve months. Such rates are generally less than the prime rate. However, we may elect to borrow at the prime rate. As of December 31, 2005, there were no borrowings under the Senior Credit Facility. The available capacity under the Senior Credit Facility as of December 31, 2005, net of $310 million of outstanding letters of credit, was approximately $1.2 billion.

The Senior Credit Facility matures on April 8, 2010, and all amounts outstanding will be due and payable at that time unless the maturity is extended. Prior to each April 8 anniversary date, we have the option to extend the maturity of the Senior Credit Facility for one year, subject to the approval of the lenders. We are working to obtain lender approval to extend the current maturity date of April 8, 2010 to April 8, 2011. If successful, this maturity date extension will be effective April 7, 2006, provided we have not experienced a "material adverse effect," as defined in the Senior Credit Facility agreement, at that date.

The Senior Credit Facility contains only one material financial covenant. This covenant requires our ratio of total funded debt to total capitalization to be less than 65%. The credit agreement contains definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in our consolidated financial statements. As defined in the agreement, total funded debt excludes the debentures that are exchangeable into shares of Chevron Corporation common stock. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling impairments or goodwill impairments. As of December 31, 2005, our ratio as calculated pursuant to this covenant was 27%.

Our access to funds from the Senior Credit Facility is not restricted under any "material adverse effect" clauses. It is not uncommon for credit agreements to include such clauses. These clauses can remove the obligation of the banks to fund the credit line if any condition or event would reasonably be expected to have a material and adverse effect on the borrower's financial condition, operations, properties or business considered as a whole, the borrower's ability to make timely debt payments, or the enforceability of material terms of the credit agreement. While our Senior Credit Facility includes covenants that require us to report a condition or event having a material adverse effect, the obligation of the banks to fund the Senior Credit Facility is not conditioned on the absence of a material adverse effect.

We also have access to short-term credit under our commercial paper program. Total borrowings under the commercial paper program may not exceed $725 million. Also, any borrowings under the commercial paper program reduce available capacity under the Senior Credit Facility on a dollar-for-dollar basis. Commercial paper debt generally has a maturity of between seven and 90 days, although it can have a maturity of up to 365 days. We had no commercial paper debt outstanding at December 31, 2005.

Debt Ratings We receive debt ratings from the major ratings agencies in the United States. In determining our debt ratings, the agencies consider a number of items including, but not limited to, debt levels, planned asset sales, near-term and long-term production growth opportunities and capital allocation challenges. Liquidity, asset quality, cost structure, reserve mix, and commodity pricing levels are also considered by the rating agencies. Our current debt ratings are BBB with a positive outlook by Standard & Poor's, Baa2 with a positive outlook by Moody's and BBB with a stable outlook by Fitch.

There are no "rating triggers" in any of our contractual obligations that would accelerate scheduled maturities should our debt rating fall below a specified level. Our cost of borrowing under our Senior Credit Facility is predicated on our corporate debt rating. Therefore, even though a ratings downgrade would not accelerate scheduled maturities, it would adversely impact the interest rate on any borrowings under our Senior Credit Facility. Under the terms of the Senior Credit Facility, a one-notch downgrade would increase the fully-drawn borrowing costs for the Senior Credit Facility from LIBOR plus 70 basis points to a new rate of LIBOR plus 87.5 basis points. A ratings downgrade could also adversely impact our ability to economically access future debt markets. As of December 31, 2005, we were not aware of any potential ratings downgrades being contemplated by the rating agencies.

Capital Expenditures In February 2006, we announced our 2006 capital expenditures budget. Our 2006 capital expenditures are expected to range from $5.0 billion to $5.2 billion. This represents the largest planned use of our 2006 operating cash flow, and is 20% to 30% higher than the 2005 capital expenditures. To a certain degree, the ultimate timing of these capital expenditures is within our control. Therefore, if oil and natural gas prices fluctuate from current estimates, we could choose to defer a portion of these planned 2006 capital expenditures until later periods or accelerate capital expenditures planned for periods beyond 2006 to achieve the desired balance between sources and uses of liquidity. Based upon current oil and natural gas price expectations for 2006, we anticipate that our capital resources will be more than adequate to fund 2006 capital expenditures.

Common Stock Repurchase Program During 2006 and 2007, we may repurchase up to 47.8 million additional shares in conjunction with our stock repurchase program announced in August 2005. We anticipate the shares would be repurchased with operating cash flow. The stock repurchase program may be discontinued at any time.

Contractual Obligations A summary of our contractual obligations as of December 31, 2005, is provided in the following table.

		PAYMENTS DUE BY YEAR						
		2006	2007	2008	2009	2010	AFTER 2010	TOTAL
					(IN MILLIONS)			
Long-term debt (1)	$	673	400	762	177	—	4,625	6,637
Interest expense (2)		453	422	401	363	345	4,195	6,179
Drilling and facility obligations (3)		666	261	180	118	93	—	1,318
Asset retirement obligations (4)		50	38	50	50	66	414	668
Firm transportation agreements (5)		102	89	66	52	38	131	478
Lease obligations (6)		53	51	46	42	34	203	429
Other		24	20	—	—	—	—	44
Total	$	2,021	1,281	1,505	802	576	9,568	15,753

(1) Long-term debt amounts represent scheduled maturities of our debt obligations at December 31, 2005, excluding $18 million of fair value adjustments included in the carrying value of debt. In addition, $387 million of letters of credit that have been issued by commercial banks on our behalf are excluded from the table. The majority of these letters of credit, if funded, would become borrowings under our revolving credit facility. Most of these letters of credit have been granted by financial institutions to support our international and Canadian drilling commitments.

(2) Interest expense amounts represent the scheduled fixed-rate and variable-rate cash payments related to our long-term debt. Interest on our variable-rate debt was estimated based upon expected future rates at December 31, 2005.

(3) Drilling and facility obligations represent contractual agreements with third party service providers to procure drilling rigs and other drilling related services for developmental and exploratory drilling.

(4) Asset retirement obligations represent estimated discounted costs for future dismantlement, abandonment and rehabilitation costs. These costs are recorded as liabilities on our December 31, 2005 balance sheet.

(5) Firm transportation agreements represent "ship or pay" arrangements whereby we have committed to ship certain volumes of oil, gas and NGLs for a fixed transportation fee. We have entered into these agreements to aid the movement of our gas production to market. We expect to have sufficient production to utilize the majority of these transportation services.

(6) Lease obligations consist of operating leases for office and equipment, an offshore platform spar and an FPSO. Office and equipment leases represent non-cancelable leases for office space and equipment used in our daily operations.

We have an offshore platform spar that is being used in the development of the Nansen field in the Gulf of Mexico. This spar is subject to a 20-year lease and contains various options whereby we may purchase the lessors' interests in the spars. We have guaranteed that the spar will have a residual value at the end of the term equal to at least 10% of the fair value of the spar at the inception of the lease. The total guaranteed value is $14 million in 2022. However, such amount may be reduced under the terms of the lease agreements. In 2005, we sold our interests in the Boomvang field in the Gulf of Mexico, which has a spar lease with terms similar to those of the Nansen lease. As a result of the sale, we are subleasing the Boomvang Spar. The table above does not include any amounts related to the Boomvang spar lease. However, if the sublessee defaults on its obligation, we would be required to continue making the lease payments and any guaranteed payment required at the end of the term.

We have an FPSO that is being used in the Panyu project offshore China. This FPSO lease term expires in September 2009.

Pension Funding and Estimates *Funded Status.* As compared to the "projected benefit obligation," our qualified and nonqualified defined benefit plans were underfunded by $133 million and $132 million at December 31, 2005, and 2004, respectively. A detailed reconciliation of the 2005 changes to our underfunded status is included in Note 11 to the accompanying consolidated financial statements. Of the $133 million underfunded status at the end of 2005, $126 million is attributable to various nonqualified defined benefit plans which have no plan assets. However, we have established certain trusts to fund the benefit obligations of such nonqualified plans. As of December 31, 2005, these trusts had investments with a fair value of $59 million. The value of these trusts is included in noncurrent other assets in our accompanying consolidated balance sheets.

As compared to the "accumulated benefit obligation," our qualified defined benefit plans were overfunded by $37 million at December 31, 2005. The accumulated benefit obligation differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. Our current intentions are to provide sufficient funding in future years to ensure the accumulated benefit obligation remains fully funded. The actual amount of contributions required during this period will depend on investment returns from the plan assets. Required contributions also depend upon changes in actuarial assumptions made during the same period, particularly the discount rate used to calculate the present value of the accumulated benefit obligation. For 2006, we expect our contributions to the plan to be less than $10 million.

Pension Estimate Assumptions. Our pension expense is recognized on an accrual basis over employees' approximate service periods and is generally calculated independent of funding decisions or requirements. We recognized expense for our defined benefit pension plans of $26 million, $26 million and $35 million in 2005, 2004 and 2003, respectively. We estimate that our pension expense will approximate $31 million in 2006.

The calculation of pension expense and pension liability requires the use of a number of assumptions. Changes in these assumptions can result in different expense and liability amounts, and future actual experience can differ from the assumptions. We believe that the two most critical assumptions affecting pension expense and liabilities are the expected long-term rate of return on plan assets and the assumed discount rate.

We assumed that our plan assets would generate a long-term weighted average rate of return of 8.40% and 8.34% at December 31, 2005 and 2004, respectively. We developed these expected long-term rate of return assumptions by evaluating input from external consultants and economists as well as long-term inflation assumptions. The expected long-term rate of return on plan assets is based on a target allocation of investment types in such assets. The target investment allocation for our plan assets is 50% U.S. large cap equity securities; 15% U.S. small cap equity securities, equally allocated between growth and value; 15% international equity securities, equally allocated between growth and value; and 20% debt securities. We expect our long-term asset allocation on average to approximate the targeted allocation. We regularly review our actual asset allocation and periodically rebalance the investments to the targeted allocation when considered appropriate.

Pension expense increases as the expected rate of return on plan assets decreases. A decrease in our long-term rate of return assumption of 100 basis points (from 8.40% to 7.40%) would increase the expected 2006 pension expense by $5 million.

We discounted our future pension obligations using a weighted average rate of 5.72% at December 31, 2005, compared to 5.74% at December 31, 2004. The discount rate is determined at the end of each year based on the rate at which obligations could be effectively settled. This rate is based on high-quality bond yields, after allowing for call and default risk. We consider high quality corporate bond yield indices, such as Moody's Aa, when selecting the discount rate.

The pension liability and future pension expense both increase as the discount rate is reduced. Lowering the discount rate by 25 basis points (from 5.72% to 5.47%) would increase our pension liability at December 31, 2005, by $23 million, and increase estimated 2006 pension expense by $3 million.

At December 31, 2005, we had unrecognized actuarial losses of $195 million which will be recognized as a component of pension expense in future years. These losses are primarily due to reductions in the discount rate since 2001. We estimate that approximately $12 million and $11 million of the unrecognized actuarial losses will be included in pension expense in 2006 and 2007, respectively. The $12 million estimated to be recognized in 2006 is a component of the total estimated 2006 pension expense of $31 million referred to earlier in this section.

Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in our defined benefit pension plans will impact future pension expense and liabilities. We cannot predict with certainty what these factors will be in the future.

On November 10, 2005, the Financial Accounting Standards Board ("FASB") announced that it expects to make significant changes in the disclosure and measurement rules for pension benefits. These expected changes will be made in two stages. The first stage of rule changes are expected to be issued in 2006. These rule changes are expected to require companies to recognize a pension asset or liability equal to the difference between the projected benefit obligation and the fair value of the plan assets. As a result, unrecognized actuarial losses and other unrecognized costs that are used to calculate the pension asset or liability under current rules will be recognized immediately as an adjustment to stockholders' equity. Had these rule changes been effective December 31, 2005, our stockholders' equity would have decreased less than 1%. The second stage of this project is expected to take several years before rule changes are presented.

CONTINGENCIES AND LEGAL MATTERS

For a detailed discussion of contingencies and legal matters, see note 12 of the accompanying consolidated financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from these estimates, and changes in these estimates are recorded when known.

The critical accounting policies used by management in the preparation of our consolidated financial statements are those that are important both to the presentation of our financial condition and results of operations and require significant judgments by management with regard to estimates used. Our critical accounting policies and significant judgments and estimates related to those policies are described below. We have reviewed these critical accounting policies with the Audit Committee of the Board of Directors.

Full Cost Ceiling Calculations

Policy Description We follow the full cost method of accounting for our oil and gas properties. The full cost method subjects companies to quarterly calculations of a "ceiling," or limitation on the amount of properties that can be capitalized on the balance sheet. The ceiling limitation is the discounted estimated after-tax future net revenues from proved oil and gas properties, excluding future cash outflows associated with settling asset retirement obligations included in the net book value of oil and gas properties, plus the cost of properties not subject to amortization. If our net book value of oil and gas properties, less related deferred income taxes, is in excess of the calculated ceiling, the excess must be written off as an expense, except as discussed in the following paragraph. The ceiling limitation is imposed separately for each country in which we have oil and gas properties.

If, subsequent to the end of the quarter but prior to the applicable financial statements being published, prices increase to levels such that the ceiling would exceed the costs to be recovered, a writedown otherwise indicated at the end of the quarter is not required to be recorded. A writedown indicated at the end of a quarter is also not required if the value of additional reserves proved up on properties after the end of the quarter but prior to the publishing of the financial statements would result in the ceiling exceeding the costs to be recovered, as long as the properties were owned at the end of the quarter. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

Judgments and Assumptions The discounted present value of future net revenues for our proved oil, natural gas and NGL reserves is a major component of the ceiling calculation, and represents the component that requires the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. The process of estimating oil, natural gas and NGL reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data. Certain of our reserve estimates are prepared or audited by outside petroleum consultants, while other reserve estimates are prepared by our engineers. See Note 15 of the accompanying consolidated financial statements.

The passage of time provides more qualitative information regarding estimates of reserves, and revisions are made to prior estimates to reflect updated information. In the past five years, annual revisions to our reserve estimates, which have been both increases and decreases in individual years, have averaged approximately 1% of the previous year's estimate. However, there can be no assurance that more significant revisions will not be necessary in the future. If future significant revisions are necessary that reduce previously estimated reserve quantities, it could result in a full cost property writedown. In addition to the impact of the estimates of proved reserves on the calculation of the ceiling, estimates of proved reserves are also a significant component of the calculation of DD&A.

While the quantities of proved reserves require substantial judgment, the associated prices of oil, natural gas and NGL reserves, and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that a 10% discount factor be used and that prices and costs in effect as of the last day of the period are held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs. Rather, they are based on such prices and costs in effect as of the end of each quarter when the ceiling calculation is performed. In calculating the ceiling, we adjust the end-of-period price by the effect of cash flow hedges in place. This adjustment requires little judgment as the end-of-period price is adjusted using the contract prices for our cash flow hedges. We had no such hedges outstanding at December 31, 2005.

Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely, and requires a 10% discount factor, the resulting value is not indicative of the true fair value of the reserves. Oil and natural gas prices have historically been volatile. On any particular day at the end of a quarter, prices can be either substantially higher or lower than our long-term price forecast that is a barometer for true fair value. Therefore, oil and gas property writedowns that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Derivative Financial Instruments

Policy Description Historically, we have used oil and gas derivative financial instruments to manage our exposure to oil and gas price volatility. We have also used interest rate swaps to manage our exposures to interest rate volatility. The interest rate swaps mitigate either the effects on interest expense for variable-rate debt instruments, or the debt fair values for fixed-rate debt. We are not involved in any speculative trading activities of derivatives. All derivatives requiring balance sheet recognition are recognized on the balance sheet at their fair value. At December 31, 2005, the only derivative financial instruments outstanding consisted of interest rate swaps.

Prior to December 31, 2005, a substantial portion of our derivatives consisted of contracts that hedged the price of future oil and natural gas production. At inception, these derivative contracts were cash flow hedges that qualified for hedge accounting treatment. Therefore, while fair values of such hedging instruments are estimated as of the end of each reporting period, the changes in the fair values attributable to the effective portion of these hedging instruments are not included in our consolidated results of operations. Instead, the changes in fair value of the effective portion of these hedging instruments, net of tax, are recorded directly to stockholders' equity until the hedged oil or natural gas quantities are produced. The ineffective portion of these hedging instruments is included in our consolidated results of operations.

To qualify for hedge accounting treatment, we designate our cash flow hedge instruments as such on the date the derivative contract is entered into or the date of a business combination which includes cash flow hedge instruments. Additionally, we document all relationships between hedging instruments and hedged items, as well as our risk-management objective and strategy for undertaking various hedge transactions. We also assess, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. If we fail to meet the requirements for using hedge accounting treatment, changes in fair value of these hedging instruments would not be recorded directly to equity but in the consolidated results of operations.

Judgments and Assumptions The estimates of the fair values of our commodity derivative contracts require substantial judgment. For these contracts, we obtain forward price and volatility data for all major oil and gas trading points in North America from independent third parties. These forward prices are compared to the price parameters contained in the hedge agreements. The resulting estimated future cash inflows or outflows over the lives of the hedge contracts are discounted using LIBOR and money market futures rates for the first year and money market futures and swap rates thereafter. In addition, we estimate the option value of price floors and price caps using an option pricing model. These pricing and discounting variables are sensitive to the period of the contract and market volatility as well as changes in forward prices, regional price differentials and interest rates. Fair values of our other derivative contracts require less judgment to estimate and are primarily based on quotes from independent third parties such as counterparties or brokers.

Quarterly changes in estimates of fair value have only a minimal impact on our liquidity, capital resources or results of operations, as long as the derivative contracts qualify for treatment as a hedge. However, settlements of derivative contracts do have an impact on our liquidity and results of operations. Generally, if actual market prices are higher than the price of the derivative contracts, our net earnings and cash flow from operations will be lower relative to the results that would have occurred absent these instruments. The opposite is also true. Additional information regarding the effects that changes in market prices will have on our derivative financial instruments, net earnings and cash flow from operations is included in the "Quantitative and Qualitative Disclosures about Market Risk" section of this report.

Business Combinations

Policy Description We have grown substantially during recent years through acquisitions of other oil and natural gas companies. Most of these acquisitions have been accounted for using the purchase method of accounting, and recent accounting pronouncements require that all future acquisitions will be accounted for using the purchase method.

Under the purchase method, the acquiring company adds to its balance sheet the estimated fair values of the acquired company's assets and liabilities. Any excess of the purchase price over the fair values of the tangible and intangible net assets acquired is recorded as goodwill. Goodwill is assessed for impairment at least annually.

Judgments and Assumptions There are various assumptions we make in determining the fair values of an acquired company's assets and liabilities. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of the oil and gas properties acquired. To determine the fair values of these properties, we prepare estimates of oil, natural gas and NGL reserves. These estimates are based on work performed by our engineers and that of outside consultants. The judgments associated with these estimated reserves are described earlier in this section in connection with the full cost ceiling calculation.

However, there are factors involved in estimating the fair values of acquired oil, natural gas and NGL properties that require more judgment than that involved in the full cost ceiling calculation. As stated above, the full cost ceiling calculation applies end-of-period price and cost information to the reserves to arrive at the ceiling amount. By contrast, the fair value of reserves acquired in a business combination must be based on our estimates of future oil, natural gas and NGL prices. Our estimates of future prices are based on our own analysis of pricing trends. These estimates are based on current data obtained with regard to regional and worldwide supply and demand dynamics such as economic growth forecasts. They are also based on industry data regarding natural gas storage availability, drilling rig activity, changes in delivery capacity, trends in regional pricing differentials and other fundamental analysis. Forecasts of future prices from independent third parties are noted when we make our pricing estimates.

We estimate future prices to apply to the estimated reserve quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues are then discounted using a rate determined appropriate at the time of the business combination based upon our cost of capital.

We also apply these same general principles to estimate the fair value of unproved properties acquired in a business combination. These unproved properties generally represent the value of probable and possible reserves. Because of their very nature, probable and possible reserve estimates are more imprecise than those of proved reserves. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net revenues of probable and possible reserves are reduced by what we consider to be an appropriate risk-weighting factor in each particular instance. It is common for the discounted future net revenues of probable and possible reserves to be reduced by factors ranging from 30% to 80% to arrive at what we consider to be the appropriate fair values.

Generally, in our business combinations, the determination of the fair values of oil and gas properties requires much more judgment than the fair values of other assets and liabilities. The acquired companies commonly have long-term debt that we assume in the acquisition, and this debt must be recorded at the estimated fair value as if we had issued such debt. However, significant judgment on our behalf is usually not required in these situations due to the existence of comparable market values of debt issued by peer companies.

Except for the 2002 Mitchell merger, our mergers and acquisitions have involved other entities whose operations were predominantly in the area of exploration, development and production activities related to oil and gas properties. However, in addition to exploration, development and production activities, Mitchell's business also included substantial marketing and midstream activities. Therefore, a portion of the Mitchell purchase price was allocated to the fair value of Mitchell's marketing and midstream facilities and equipment. This consisted primarily of natural gas processing plants and natural gas pipeline systems.

The Mitchell midstream assets primarily served gas producing properties that we also acquired from Mitchell. Therefore, certain of the assumptions regarding future operations of the gas producing properties were also integral to the value of the midstream assets. For example, future quantities of natural gas estimated to be processed by natural gas processing plants were based on the same estimates used to value the proved and unproved gas producing properties. Future expected prices for marketing and midstream product sales were also based on price cases consistent with those used to value the oil and gas producing assets acquired from Mitchell. Based on historical costs and known trends and commitments, we also estimated future operating and capital costs of the marketing and midstream assets to arrive at estimated future cash flows. These cash flows were discounted at rates consistent with those used to discount future net cash flows from oil and gas producing assets to arrive at our estimated fair value of the marketing and midstream facilities and equipment.

In addition to the valuation methods described above, we perform other quantitative analyses to support the indicated value in any business combination. These analyses include information related to comparable companies, comparable transactions and premiums paid.

In a comparable companies analysis, we review the public stock market trading multiples for selected publicly traded independent exploration and production companies with comparable financial and operating characteristics. Such characteristics are market capitalization, location of proved reserves and the characterization of those reserves that we deem to be similar to those of the party to the proposed business combination. We compare these comparable company multiples to the proposed business combination company multiples for reasonableness.

In a comparable transactions analysis, we review certain acquisition multiples for selected independent exploration and production company transactions and oil and gas asset packages announced recently. We compare these comparable transaction multiples to the proposed business combination transaction multiples for reasonableness.

In a premiums paid analysis, we use a sample of selected independent exploration and production company transactions in addition to selected transactions of all publicly traded companies announced recently, to review the premiums paid to the price of the target one day, one week and one month prior to the announcement of the transaction. We use this information to determine the mean and median premiums paid and compare them to the proposed business combination premium for reasonableness.

While these estimates of fair value for the various assets acquired and liabilities assumed have no effect on our liquidity or capital resources, they can have an effect on the future results of operations. Generally, the higher the fair value assigned to both the oil and gas properties and non-oil and gas properties, the lower future net earnings will be as a result of higher future depreciation, depletion and amortization expense. Also, a higher fair value assigned to the oil and gas properties, based on higher future estimates of oil and gas prices, will increase the likelihood of a full cost ceiling writedown in the event that subsequent oil and gas prices drop below our price forecast that was used to originally determine fair value. A full cost ceiling writedown would have no effect on our liquidity or capital resources in that period because it is a noncash charge, but it would adversely affect results of operations. As discussed in the Capital Resources, Uses and Liquidity section of this report, in calculating our debt-to-capitalization ratio under our credit agreement, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling property impairments or goodwill impairments.

Our estimates of reserve quantities are one of the many estimates that are involved in determining the appropriate fair value of the oil and gas properties acquired in a business combination. As previously disclosed in our discussion of the full cost ceiling calculations, during the past five years, our annual revisions to our reserve estimates have averaged approximately 1%. As discussed in the preceding paragraphs, there are numerous estimates in addition to reserve quantity estimates that are involved in determining the fair value of oil and gas properties acquired in a business combination. The inter-relationship of these estimates makes it impractical to provide additional quantitative analyses of the effects of changes in these estimates.

Valuation of Goodwill

Policy Description Goodwill is tested for impairment at least annually. This requires us to estimate the fair values of our own assets and liabilities in a manner similar to the process described above for a business combination. Therefore, considerable judgment similar to that described above in connection with estimating the fair value of an acquired company in a business combination is also required to assess goodwill for impairment.

Judgments and Assumptions Generally, the higher the fair value assigned to both the oil and gas properties and non-oil and gas properties, the lower goodwill would be. A lower goodwill value decreases the likelihood of an impairment charge. However, unfavorable changes in reserves or in our price forecast would increase the likelihood of a goodwill impairment charge. A goodwill impairment charge would have no effect on liquidity or capital resources. However, it would adversely affect our results of operations in that period.

Due to the inter-relationship of the various estimates involved in assessing goodwill for impairment, it is impractical to provide quantitative analyses of the effects of potential changes in these estimates, other than to note the historical average changes in our reserve estimates previously set forth.

RECENTLY ISSUED ACCOUNTING STANDARDS NOT YET ADOPTED

In December 2004, the FASB issued SFAS No. 123(R), “Share-Based Payment,” (“SFAS No. 123(R)”) which is a revision of SFAS No. 123 and supersedes APB Opinion No. 25 regarding stock-based employee compensation plans. APB Opinion No. 25 requires recognition of compensation expense only if the current market price of the underlying stock exceeded the stock option exercise price on the date of grant. Additionally, SFAS No. 123 established fair value-based accounting for stock-based employee compensation plans but allowed pro forma disclosure as an alternative to financial statement recognition. SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, to be valued at fair value on the date of grant, and to be expensed over the applicable vesting period. Also, pro forma disclosure of the income statement effects of share-based payments is no longer an alternative. We will adopt the provisions of SFAS No. 123(R) in the first quarter of 2006 using the modified prospective method. Under this method, we will recognize compensation expense for all stock-based awards granted or modified on or after January 1, 2006, as well as any previously granted awards that are not fully vested as of January 1, 2006. Compensation expense will be measured based on the fair value of the awards previously calculated in developing the pro forma disclosures in accordance with the provisions of SFAS No. 123. Based on our current estimates of the amount of 2006 stock option grants and the various assumptions used to estimate the fair value of these stock option grants, we expect stock option expense, net of related capitalization in accordance with the full cost method of accounting for oil and gas properties, will be approximately $35 million. No retroactive or cumulative effect adjustments will be recorded upon adoption.

2006 ESTIMATES

The forward-looking statements provided in this discussion are based on our examination of historical operating trends, the information which was used to prepare the December 31, 2005 reserve reports and other data in our possession or available from third parties. These forward-looking statements were prepared assuming demand, curtailment, producibility and general market conditions for our oil, natural gas and NGLs during 2006 will be substantially similar to those of 2005, unless otherwise noted. Please refer to “Risk Factors to Foward-Looking Estimates” beginning on page 99 for a discussion of relevant risk factors. Amounts related to Canadian operations have been converted to U.S. dollars using a projected average 2006 exchange rate of $0.87 U.S. dollar to $1.00 Canadian dollar.

Oil, Gas and NGL Production and Prices

Set forth in the following paragraphs are individual estimates of oil, gas and NGL production for 2006. On a combined basis, we estimate our 2006 oil, gas and NGL production will total approximately 217 MMBoe. Of this total, approximately 95% is estimated to be produced from reserves classified as "proved" at December 31, 2005.

Oil Production Oil production in 2006 is expected to total approximately 58 MMBbls. Of this total, approximately 99% is estimated to be produced from reserves classified as "proved" at December 31, 2005. The expected production by area is as follows:

	MMBBLS
United States Onshore	11
United States Offshore	9
Canada	14
International	24

Oil Prices We have not fixed the price we will receive on any of our 2006 oil production. Our 2006 average prices for each of our areas are expected to differ from the NYMEX price as set forth in the following table. The NYMEX price is the monthly average of settled prices on each trading day for benchmark West Texas Intermediate crude oil delivered at Cushing, Oklahoma.

	EXPECTED RANGE OF OIL PRICES AS A % OF NYMEX PRICE
United States Onshore	86% to 94%
United States Offshore	86% to 94%
Canada	65% to 75%
International	80% to 88%

Gas Production Gas production in 2006 is expected to total approximately 820 Bcf. Of this total, approximately 94% is estimated to be produced from reserves classified as "proved" at December 31, 2005. The expected production by area is as follows:

	BCF
United States Onshore	492
United States Offshore	75
Canada	243
International	10

Gas Prices – Fixed The price for approximately 2% of our estimated 2006 natural gas production has been fixed via various fixed-price physical delivery contracts. The following table includes information on this fixed-price production by area. Where necessary, the prices have been adjusted for certain transportation costs that are netted against the prices recorded by us, and the prices have also been adjusted for the expected Btu content of the gas hedged.

	MCF/DAY	PRICE/MCF	MONTHS OF PRODUCTION
Canada	38,578	$ 3.33	Jan – Dec
International	12,000	$ 2.15	Jan – Dec

Gas Prices – Floating For the natural gas production for which prices have not been fixed, our 2006 average prices for each of our areas are expected to differ from the NYMEX price as set forth in the following table. The NYMEX price is determined to be the first-of-month South Louisiana Henry Hub price index as published monthly in Inside FERC.

	EXPECTED RANGE OF GAS PRICES AS A % OF NYMEX PRICE
United States Onshore	74% to 84%
United States Offshore	92% to 102%
Canada	80% to 90%
International	50% to 70%

NGL Production We expect our 2006 production of NGLs to total approximately 22 MMBbls. Of this total, 97% is estimated to be produced from reserves classified as "proved" at December 31, 2005. The expected production by area is as follows:

	MMBBLS
United States Onshore	17
United States Offshore	1
Canada	4

Marketing and Midstream Revenues and Expenses

Marketing and midstream revenues and expenses are derived primarily from our natural gas processing plants and natural gas transport pipelines. These revenues and expenses vary in response to several factors. The factors include, but are not limited to, changes in production from wells connected to the pipelines and related processing plants, changes in the absolute and relative prices of natural gas and NGLs, provisions of the contract agreements and the amount of repair and workover activity required to maintain anticipated processing levels.

These factors, coupled with uncertainty of future natural gas and NGL prices, increase the uncertainty inherent in estimating future marketing and midstream revenues and expenses. Given these uncertainties, we estimate that 2006 marketing and midstream revenues will be between $1.74 billion and $2.20 billion, and marketing and midstream expenses will be between $1.38 billion and $1.80 billion.

Production and Operating Expenses

Our production and operating expenses include lease operating expenses, transportation costs and production taxes. These expenses vary in response to several factors. Among the most significant of these factors are additions to or deletions from the property base, changes in the general price level of services and materials that are used in the operation of the properties, the amount of repair and workover activity required and changes in production tax rates. Oil, natural gas and NGL prices also have an effect on lease operating expenses and impact the economic feasibility of planned workover projects.

Given these uncertainties, we estimate that 2006 lease operating expenses (including transportation costs) will be between $1.43 billion and $1.50 billion and production taxes will be between 3.25% and 3.75% of consolidated oil, natural gas and NGL revenues.

DD&A

The 2006 oil and gas property DD&A rate will depend on various factors. Most notable among such factors are the amount of proved reserves that will be added from drilling or acquisition efforts in 2006 compared to the costs incurred for such efforts, and the revisions to our year-end 2005 reserve estimates that, based on prior experience, are likely to be made during 2006.

Given these uncertainties, we expect the oil and gas property related DD&A rate will be between $9.30 per Boe and $9.50 per Boe. Based on these DD&A rates and the production estimates set forth earlier, oil and gas property related DD&A expense for 2006 is expected to be between $2.02 billion and $2.06 billion.

Additionally, we expect depreciation and amortization expense related to non-oil and gas property fixed assets to total between $170 million and $180 million.

Accretion of Asset Retirement Obligation

The 2006 accretion of asset retirement obligation is expected to be between $48 million and $53 million.

G&A

Our G&A includes employee compensation and benefits costs and the costs of many different goods and services used in support of our business. G&A varies with the level of our operating activities and the related staffing and professional services requirements. In addition, employee compensation and benefits costs vary due to various market factors that affect the level and type of compensation and benefits offered to employees. Also, goods and services are subject to general price level increases or decreases. Therefore, significant variances in any of these factors from current expectations could cause actual G&A to vary materially from the estimate.

Given these limitations, consolidated G&A in 2006 is expected to be between $360 million and $380 million. This estimate includes $35 million of expenses related to restricted stock compensation costs, net of related capitalization in accordance with the full cost method of accounting for oil and gas properties. This estimate also includes $35 million of expenses related to stock option compensation costs, net of related capitalization.

Reduction of Carrying Value of Oil and Gas Properties

We follow the full cost method of accounting for our oil and gas properties described in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates." Reductions to the carrying value of our oil and gas properties are largely dependent on the success of drilling results and oil and natural gas prices at the end of our quarterly reporting periods. Due to the uncertain nature of future drilling efforts and oil and natural gas prices, we are not able to predict whether we will incur such reductions in 2006.

Interest Expense

Future interest rates and debt outstanding have a significant effect on our interest expense. We can only marginally influence the prices we will receive in 2006 from sales of oil, natural gas and NGLs and the resulting cash flow. These factors increase the margin of error inherent in estimating future interest expense. Other factors which affect interest expense, such as the amount and timing of capital expenditures, are within our control.

Based on the information related to interest expense set forth below and assuming no material changes in our expected level of indebtedness or prevailing interest rates, we expect our 2006 interest expense (net of amounts capitalized) will be between $385 million and $395 million. Details of this estimate are discussed in the following paragraphs.

The interest expense in 2006 related to our fixed-rate debt, including net accretion of related discounts, will be approximately $410 million. This fixed-rate debt removes the uncertainty of future interest rates from some, but not all, of our long-term debt. Our floating rate debt is discussed in the following paragraphs.

We have various debt instruments which have been converted to floating rate debt through the use of interest rate swaps. Our floating rate debt is as follows:

DEBT INSTRUMENT	NOTIONAL AMOUNT (IN MILLIONS)	FLOATING RATE
2.75% notes due in August 2006	$ 500	LIBOR less 26.8 basis points
6.55% senior notes due in August 2006	$ 172 (1)	Banker's Acceptance plus 340 basis points
4.375% senior notes due in October 2007	$ 400	LIBOR plus 40 basis points

(1) Converted from $200 million Canadian dollars at a Canadian-to-U.S. dollar exchange rate of $0.8577 at December 31, 2005.

Based on future LIBOR rates as of January 31, 2006, interest expense on our floating rate debt, including net amortization of premiums, is expected to total between $35 million and $45 million in 2006.

Our interest expense totals include payments of facility and agency fees, amortization of debt issuance costs, the effect of interest rate swaps not accounted for as hedges, and other miscellaneous items not related to the debt balances outstanding. We expect between $5 million and $15 million of such items to be included in 2006 interest expense. Also, we expect to capitalize between $65 million and $75 million of interest during 2006.

Effects of Changes in Foreign Currency Rates

Foreign currency gains or losses are not expected to be material in 2006.

Other Revenues

Our other revenues in 2006 are expected to be between $155 million and $175 million.

We maintain a comprehensive insurance program that includes coverage for physical damage to our offshore facilities caused by hurricanes. Our insurance program also includes substantial business interruption coverage which we expect to utilize to recover costs associated with the suspended production related to hurricanes that struck the Gulf of Mexico in the third quarter of 2005. Under the terms of the insurance program, we are entitled to be reimbursed for the portion of production suspended longer than forty-five days, subject to upper limits to oil and natural gas prices. Also, the terms of the insurance include a standard, per-event deductible of $1 million for offshore losses as well as a $15 million aggregate annual deductible. Based on current estimates of physical damage and the anticipated length of time we will have production suspended, we expect our policy settlements will exceed repair costs and deductible amounts. As a result, 2006 and 2007 other revenues are expected to include more than $150 million for anticipated insurance proceeds in excess of repair costs. This estimate is dependent upon several variables, including the actual amount of time that production is suspended, the actual prices in effect while production is suspended and the timing of collections of insurance proceeds. Based on current estimates of the timing of collections of insurance proceeds, we expect 2006 other revenues will include $50 million to $70 million for anticipated insurance proceeds, with the balance to be recorded in 2007. Significant variances in any of these factors from current estimates could cause actual 2006 other revenues to vary materially from the estimate.

Income Taxes

Our financial income tax rate in 2006 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2006 will be significantly affected by the proportional share of consolidated pre-tax earnings generated by U.S., Canadian and International operations due to the different tax rates of each country. There are certain tax deductions and credits that will have a fixed impact on 2006 income tax expense regardless of the level of pre-tax earnings that are produced.

Given the uncertainty of pre-tax earnings, we expect our consolidated financial income tax rate in 2006 will be between 25% and 45%. The current income tax rate is expected to be between 20% and 30%. The deferred income tax rate is expected to be between 5% and 15%. Significant changes in estimated capital expenditures, production levels of oil, gas and NGLs, the prices of such products, marketing and midstream revenues, or any of the various expense items could materially alter the effect of the aforementioned tax deductions and credits on the 2006 financial income tax rates.

Year 2006 Potential Capital Sources, Uses and Liquidity

Capital Expenditures Though we have completed several major property acquisitions in recent years, these transactions are opportunity driven. Thus, we do not budget, nor can we reasonably predict, the timing or size of such possible acquisitions, if any.

Our capital expenditures budget is based on an expected range of future oil, natural gas and NGL prices as well as the expected costs of the capital additions. Should actual prices received differ materially from our price expectations for future production, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2006 capital expenditures. In addition, if the actual material or labor costs of the budgeted items vary significantly from the anticipated amounts, actual capital expenditures could vary materially from our estimates.

Given the limitations discussed above, the following table shows expected drilling, development and facilities expenditures by geographic area. Production capital related to proved reserves relates to reserves classified as proved as of year-end 2005. Other production capital includes development drilling that does not offset currently productive units and for which there is not a certainty of continued production from a known productive formation. Exploration capital includes exploratory drilling to find and produce oil or gas in previously untested fault blocks or new reservoirs.

	UNITED STATES ONSHORE	UNITED STATES OFFSHORE	CANADA	INTERNATIONAL	TOTAL
			(IN MILLIONS)		
Production capital related to proved reserves	$ 370-$ 390	$ 85-$ 95	$ 530-$ 550	$220-$230	$1,205-$1,265
Other production capital	$1,380-$1,430	$120-$130	$ 570-$ 590	$ 20-$ 25	$2,090-$2,175
Exploration capital	$ 260-$ 270	$250-$270	$ 200-$ 210	$270-$280	$ 980-$1,030
Total	$2,010-$2,090	$455-$495	$1,300-$1,350	$510-$535	$4,275-$4,470

In addition to the above expenditures for drilling, development and facilities, we expect to spend between $255 million to $275 million on marketing and midstream assets, which include our oil pipelines, gas processing plants, CO_2 removal facilities and gas transport pipelines. We also expect to capitalize between $230 million and $240 million of G&A expenses in accordance with the full cost method of accounting and to capitalize between $65 million and $75 million of interest. We also expect to pay between $35 million and $45 million for plugging and abandonment charges and to spend between $130 million and $140 million for other non-oil and gas property fixed assets.

Other Cash Uses We expect to continue the policy of paying a quarterly common stock dividend. With the current $0.1125 per share quarterly dividend rate and 443 million shares of common stock outstanding as of December 31, 2005, dividends are expected to approximate $200 million. Also, we have $150 million of 6.49% cumulative preferred stock upon which we will pay $10 million of dividends in 2006.

On August 3, 2005, we announced our intention to repurchase up to 50 million shares of our common stock. This stock repurchase program is planned to extend through 2007. During this period, shares may be purchased from time to time depending upon market conditions. We plan to repurchase shares in the open market and in privately negotiated transactions. As of February 28, 2006, we had repurchased 4.4 million shares under the program for $267 million.

Capital Resources and Liquidity Our estimated 2006 cash uses, including drilling and development activities and repurchase of common stock, are expected to be funded primarily through a combination of working capital (which totaled $1.3 billion at the end of 2005) and operating cash flow. The remainder, if any, could be funded with borrowings from our credit facility. We expect our combined capital resources to be more than adequate to fund anticipated capital expenditures and other cash uses for 2006 without the use of the available credit facility.

If significant acquisitions or other unplanned capital requirements arise during the year, we could utilize our existing credit facilities and/or seek to establish and utilize other sources of financing.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil, gas and NGL prices, interest rates and foreign currency exchange rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil, gas and NGL production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. and Canadian natural gas and NGL production. Pricing for oil, gas and NGL production has been volatile and unpredictable for several years.

Currently, we are largely accepting the volatility risk that oil and natural gas prices present. None of our future oil and natural gas production is subject to price swaps or collars. In addition, none of our estimated 2006 oil production, and only 2% of our estimated 2006 natural gas production, is subject to fixed-price physical delivery contracts as summarized in the table below.

	MCF/DAY	PRICE/MCF	MONTHS OF PRODUCTION
Canada	38,578	$ 3.33	Jan – Dec
International	12,000	$ 2.15	Jan – Dec

In addition, we have fixed-price physical delivery contracts for the years 2007 through 2011 covering Canadian natural gas production ranging from seven Bcf to 14 Bcf per year. We also have fixed-price physical delivery contracts covering International gas production of four Bcf in 2007 and three Bcf in 2008.

Interest Rate Risk

At December 31, 2005, we had debt outstanding of $6.6 billion. Of this amount, $5.5 billion, or 84%, bears interest at fixed rates averaging 7.4%.

The remaining $1.1 billion of debt outstanding bears interest at floating rates. Included in the floating-rate debt is fixed-rate debt which has been converted to floating-rate debt through interest rate swaps. Following is a table summarizing the fixed-to-floating interest rate swaps with the related debt instrument and notional amounts.

DEBT INSTRUMENT	NOTIONAL AMOUNT (IN MILLIONS)	FLOATING RATE
2.75% notes due in 2006	$ 500	LIBOR less 26.8 basis points
6.55% senior notes due 2006	$ 172 (1)	Banker's Acceptance plus 340 basis points
4.375% senior notes due in 2007	$ 400	LIBOR plus 40 basis points

(1) Converted from $200 million Canadian dollars at a Canadian-to-U.S. dollar exchange rate of $0.8577 at December 31, 2005.

We use a sensitivity analysis technique to evaluate the hypothetical effect that changes in interest rates may have on the fair value of our interest rate swap instruments. At December 31, 2005, a 10% increase in the underlying interest rates would have decreased the fair value of our interest rate swaps by $8 million.

The above sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments.

Foreign Currency Risk

Our net assets, net earnings and cash flows from our Canadian subsidiaries are based on the U.S. dollar equivalent of such amounts measured in the Canadian dollar functional currency. Assets and liabilities of the Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period. A 10% unfavorable change in the Canadian-to-U.S. dollar exchange rate would not materially impact our December 31, 2005 balance sheet.

The Board of Directors and Stockholders
Devon Energy Corporation:

We have audited the accompanying consolidated balance sheets of Devon Energy Corporation and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss) and cash flows for each of the years in the three-year period ended December 31, 2005. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits 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 includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Devon Energy Corporation and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

As described in Note 1 to the consolidated financial statements, as of January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, *Asset Retirement Obligations.*

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Devon Energy Corporation's internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2006 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Oklahoma City, Oklahoma
February 28, 2006

Management's Annual Report on Internal Control Over Financial Reporting

Devon's management is responsible for establishing and maintaining adequate internal control over financial reporting for Devon, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Under the supervision and with the participation of Devon's management, including our principal executive and principal financial officers, Devon conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). Based on this evaluation under the COSO Framework which was completed on February 10, 2006, management concluded that its internal control over financial reporting was effective as of December 31, 2005.

Management's assessment of the effectiveness of Devon's internal control over financial reporting as of December 31, 2005 has been audited by KPMG LLP, an independent registered public accounting firm who audited Devon's consolidated financial statements as of and for the year ended December 31, 2005, as stated in their report which is included herein.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Devon Energy Corporation:

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting that Devon Energy Corporation maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Devon Energy Corporation'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 an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit 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. Our audit included 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 considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

In our opinion, management's assessment that Devon Energy Corporation maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, Devon Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Devon Energy Corporation and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss) and cash flows for each of the years in the three-year period ended December 31, 2005, and our report dated February 28, 2006 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Oklahoma City, Oklahoma
February 28, 2006

Consolidated Balance Sheets

DECEMBER 31, (IN MILLIONS, EXCEPT SHARE DATA)		2005	2004
ASSETS			
Current assets:			
Cash and cash equivalents	$	1,606	1,152
Short-term investments		680	967
Accounts receivable		1,601	1,320
Deferred income taxes		158	289
Other current assets		161	144
Total current assets		4,206	3,872
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($2,747 and $3,187 excluded from amortization in 2005 and 2004, respectively)		34,246	32,114
Less accumulated depreciation, depletion and amortization		15,114	12,768
		19,132	19,346
Investment in Chevron Corporation common stock, at fair value		805	745
Goodwill		5,705	5,637
Other assets		425	425
Total assets	$	30,273	30,025
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable:			
Trade	$	947	715
Revenues and royalties due to others		666	487
Income taxes payable		293	223
Current portion of long-term debt		662	933
Accrued interest payable		127	139
Fair value of derivative financial instruments		18	399
Current portion of asset retirement obligation		50	46
Accrued expenses and other current liabilities		171	158
Total current liabilities		2,934	3,100
Debentures exchangeable into shares of Chevron Corporation common stock		709	692
Other long-term debt		5,248	6,339
Fair value of derivative financial instruments		125	72
Asset retirement obligation, long-term		618	693
Other liabilities		372	366
Deferred income taxes		5,405	5,089
Stockholders' equity:			
Preferred stock of $1.00 par value. Authorized 4,500,000 shares; issued 1,500,000 ($150 million aggregate liquidation value)		1	1
Common stock of $0.10 par value. Authorized 800,000,000 shares; issued 443,451,000 in 2005 and 483,909,000 in 2004		44	48
Additional paid-in capital		7,066	9,087
Retained earnings		6,477	3,693
Accumulated other comprehensive income		1,414	930
Deferred compensation and other		(138)	(85)
Treasury stock, at cost: 37,000 shares in 2005		(2)	—
Total stockholders' equity		14,862	13,674
Commitments and contingencies (Note 12)			
Total liabilities and stockholders' equity	$	30,273	30,025

See accompanying notes to consolidated financial statements.

Consolidated Statements of Operations

DEVON ENERGY CORPORATION AND SUBSIDIARIES

YEAR ENDED DECEMBER 31, (IN MILLIONS, EXCEPT PER SHARE AMOUNTS)		2005	2004	2003
REVENUES:				
Oil sales	$	2,478	2,202	1,588
Gas sales		5,784	4,732	3,897
NGL sales		687	554	407
Marketing and midstream revenues		1,792	1,701	1,460
Total revenues		10,741	9,189	7,352
EXPENSES AND OTHER INCOME, NET:				
Lease operating expenses		1,345	1,280	1,078
Production taxes		335	255	204
Marketing and midstream operating costs and expenses		1,342	1,339	1,174
Depreciation, depletion and amortization of oil and gas properties		2,031	2,141	1,668
Depreciation and amortization of non-oil and gas properties		160	149	125
Accretion of asset retirement obligation		44	44	36
General and administrative expenses		291	277	307
Expenses related to mergers		—	—	7
Interest expense		533	475	502
Effects of changes in foreign currency exchange rates		(2)	(23)	(69)
Change in fair value of derivative financial instruments		94	62	(1)
Reduction of carrying value of oil and gas properties		212	—	111
Other income, net		(196)	(103)	(35)
Total expenses and other income, net		6,189	5,896	5,107
Earnings before income tax expense and cumulative change in accounting principle		4,552	3,293	2,245
INCOME TAX EXPENSE:				
Current		1,238	752	193
Deferred		384	355	321
Total income tax expense		1,622	1,107	514
Earnings before cumulative effect of change in accounting principle		2,930	2,186	1,731
Cumulative change in accounting principle, net of tax		—	—	16
Net earnings		2,930	2,186	1,747
Preferred stock dividends		10	10	10
Net earnings applicable to common stockholders	$	2,920	2,176	1,737
BASIC NET EARNINGS PER SHARE:				
Earnings before cumulative effect of change in accounting principle	$	6.38	4.51	4.12
Cumulative effect of change in accounting principle, net of tax		—	—	0.04
Net earnings	$	6.38	4.51	4.16
DILUTED NET EARNINGS PER SHARE:				
Earnings before cumulative effect of change in accounting principle	$	6.26	4.38	4.00
Cumulative effect of change in accounting principle, net of tax		—	—	0.04
Net earnings	$	6.26	4.38	4.04
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic		458	482	417
Diluted		470	499	433

See accompanying notes to consolidated financial statements.

Consolidated Statements of Stockholders' Equity and Comprehensive Income (Loss)

(IN MILLIONS)		PREFERRED STOCK	COMMON STOCK	ADDITIONAL PAID-IN CAPITAL	RETAINED EARNINGS (ACCUMULATED DEFICIT)	ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	DEFERRED COMPENSATION AND OTHER	TREASURY STOCK	TOTAL STOCKHOLDERS' EQUITY
BALANCE AS OF DECEMBER 31, 2002	$	1	31	5,163	(84)	(267)	(3)	(188)	4,653
Comprehensive income:									
Net earnings		—	—	—	1,747	—	—	—	1,747
Other comprehensive income (loss), net of tax:									
Foreign currency translation adjustments		—	—	—	—	766	—	—	766
Reclassification adjustment for derivative losses reclassified into oil and gas sales		—	—	—	—	198	—	—	198
Change in fair value of derivative financial instruments		—	—	—	—	(236)	—	—	(236)
Minimum pension liability adjustment		—	—	—	—	19	—	—	19
Unrealized gain on marketable securities		—	—	—	—	89	—	—	89
Other comprehensive income									836
Comprehensive income									2,583
Stock issued		—	15	3,816	—	—	—	2	3,833
Tax benefit related to employee stock options		—	—	31	—	—	—	—	31
Dividends on common stock		—	—	—	(39)	—	—	—	(39)
Dividends on preferred stock		—	—	—	(10)	—	—	—	(10)
Grant of restricted stock awards, net of cancellations		—	—	34	—	—	(34)	—	—
Amortization of restricted stock awards		—	—	—	—	—	2	—	2
Other		—	1	(1)	—	—	3	—	3
BALANCE AS OF DECEMBER 31, 2003		1	47	9,043	1,614	569	(32)	(186)	11,056
Comprehensive income:									
Net earnings		—	—	—	2,186	—	—	—	2,186
Other comprehensive income (loss), net of tax:									
Foreign currency translation adjustments		—	—	—	—	388	—	—	388
Reclassification adjustment for derivative losses reclassified into oil and gas sales		—	—	—	—	410	—	—	410
Change in fair value of derivative financial instruments		—	—	—	—	(561)	—	—	(561)
Minimum pension liability adjustment		—	—	—	—	39	—	—	39
Unrealized gain on marketable securities		—	—	—	—	85	—	—	85
Other comprehensive income									361
Comprehensive income									2,547
Stock issued		—	1	264	—	—	—	(21)	244
Stock repurchased and retired		—	—	(189)	—	—	—	—	(189)
Conversion of preferred stock of a subsidiary		—	—	—	—	—	—	56	56
Tax benefit related to employee stock options		—	—	54	—	—	—	—	54
Dividends on common stock		—	—	—	(97)	—	—	—	(97)
Dividends on preferred stock		—	—	—	(10)	—	—	—	(10)
Grant of restricted stock awards, net of cancellations		—	—	66	—	—	(66)	—	—
Amortization of restricted stock awards		—	—	—	—	—	11	—	11
Retirement of treasury stock		—	—	(151)	—	—	—	151	—
Other		—	—	—	—	—	2	—	2
BALANCE AS OF DECEMBER 31, 2004		1	48	9,087	3,693	930	(85)	—	13,674
Comprehensive income:									
Net earnings		—	—	—	2,930	—	—	—	2,930
Other comprehensive income (loss), net of tax:									
Foreign currency translation adjustments		—	—	—	—	162	—	—	162
Reclassification adjustment for derivative losses reclassified into oil and gas sales		—	—	—	—	444	—	—	444
Change in fair value of derivative financial instruments		—	—	—	—	(155)	—	—	(155)
Minimum pension liability adjustment		—	—	—	—	(5)	—	—	(5)
Unrealized gain on marketable securities		—	—	—	—	38	—	—	38
Other comprehensive income									484
Comprehensive income									3,414
Stock issued		—	1	125	—	—	—	—	126
Stock repurchased and retired		—	(5)	(2,270)	—	—	—	(2)	(2,277)
Tax benefit related to employee stock options		—	—	44	—	—	—	—	44
Dividends on common stock		—	—	—	(136)	—	—	—	(136)
Dividends on preferred stock		—	—	—	(10)	—	—	—	(10)
Grant of restricted stock awards, net of cancellations		—	—	80	—	—	(80)	—	—
Amortization of restricted stock awards		—	—	—	—	—	27	—	27
Balance as of December 31, 2005	$	1	44	7,066	6,477	1,414	(138)	(2)	14,862

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

YEAR ENDED DECEMBER 31, (IN MILLIONS)	2005	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net earnings	$ 2,930	2,186	1,731
Adjustments to reconcile net earnings to net cash provided by operating activities:			
Depreciation, depletion and amortization	2,191	2,290	1,793
Accretion of asset retirement obligation	44	44	36
Amortization of (premiums) discounts on long-term debt, net	—	(5)	4
Effects of changes in foreign currency exchange rates	(2)	(23)	(69)
Non-cash change in fair value of derivative financial instruments	55	62	(1)
Deferred income tax expense	384	355	321
Net (gain) loss on sale of assets	(150)	(34)	7
Reduction of carrying value of oil and gas properties	212	—	111
Other	31	31	(48)
Changes in assets and liabilities, net of effects of acquisitions of businesses:			
(Increase) decrease in:			
Accounts receivable	(270)	(345)	(164)
Other current assets	(16)	(20)	(34)
Long-term other assets	52	(91)	—
Increase (decrease) in:			
Accounts payable	262	190	42
Income taxes payable	69	208	62
Accrued interest and expenses	(41)	(79)	(2)
Long-term debt, including current maturities	(67)	16	15
Long-term other liabilities	(72)	31	(36)
Net cash provided by operating activities	5,612	4,816	3,768
CASH FLOWS FROM INVESTING ACTIVITIES:			
Proceeds from sale of property and equipment	2,151	95	179
Capital expenditures, including acquisitions of businesses	(4,090)	(3,103)	(2,587)
Purchases of short-term investments	(4,020)	(3,215)	(702)
Sales of short-term investments	4,307	2,589	361
Other	—	—	(24)
Net cash used in investing activities	(1,652)	(3,634)	(2,773)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings of long-term debt, net of issuance costs	—	—	597
Principal payments on long-term debt	(1,258)	(973)	(1,118)
Issuance of common stock, net of issuance costs	124	268	155
Repurchase of common stock	(2,263)	(189)	—
Dividends paid on common stock	(136)	(97)	(39)
Dividends paid on preferred stock	(10)	(10)	(10)
Increase in long-term other liabilities	—	—	1
Net cash used in financing activities	(3,543)	(1,001)	(414)
Effect of exchange rate changes on cash	37	39	59
Net increase in cash and cash equivalents	454	220	640
Cash and cash equivalents at beginning of year	1,152	932	292
Cash and cash equivalents at end of year	$ 1,606	1,152	932

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Accounting policies used by Devon Energy Corporation and subsidiaries ("Devon") reflect industry practices and conform to accounting principles generally accepted in the United States of America. The more significant of such policies are briefly discussed below.

Nature of Business and Principles of Consolidation

Devon is engaged primarily in oil and gas exploration, development and production, and the acquisition of properties. Such activities domestically are concentrated in four geographic areas:

- the Permian Basin within Texas and New Mexico;
- the Rocky Mountains area of the United States stretching from the Canadian Border into Northern New Mexico;
- the Mid-Continent area of the central and southern United States; and
- the Gulf Coast, which includes properties located primarily in the onshore South Texas and South Louisiana areas and offshore in the Gulf of Mexico.

Devon's Canadian activities are located primarily in the Western Canadian Sedimentary Basin. Devon's international activities — outside of North America — are located primarily in Azerbaijan, Brazil, China, Egypt, Russia, and areas in West Africa, including Equatorial Guinea, Gabon and Cote d'Ivoire.

Devon also has marketing and midstream operations which are responsible for marketing natural gas, crude oil and NGLs, and constructing and operating pipelines, storage and treating facilities and gas processing plants. These services are performed for Devon as well as for unrelated third parties.

The accounts of Devon's wholly owned subsidiaries are included in the accompanying consolidated financial statements. All significant intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from these estimates, and changes in these estimates are recorded when known. Significant items subject to such estimates and assumptions include estimates of proved reserves and related present value estimates of future net revenue, the carrying value of oil and gas properties, goodwill impairment assessment, asset retirement obligations, income taxes, valuation of derivative instruments, obligations related to employee benefits and legal and environmental risks and exposures.

Property and Equipment

Devon follows the full cost method of accounting for its oil and gas properties. Accordingly, all costs incidental to the acquisition, exploration and development of oil and gas properties, including costs of undeveloped leasehold, dry holes and leasehold equipment, are capitalized. Internal costs incurred that are directly identified with acquisition, exploration and development activities undertaken by Devon for its own account, and which are not related to production, general corporate overhead or similar activities, are also capitalized. Interest costs incurred and attributable to unproved oil and gas properties under current evaluation and major development projects of oil and gas properties are also capitalized.

Unproved properties are excluded from amortized capitalized costs until it is determined whether or not proved reserves can be assigned to such properties. Devon assesses its unproved properties for impairment quarterly. Significant unproved properties are assessed individually. Costs of insignificant unproved properties are transferred to amortizable costs over average holding periods ranging from three years for onshore properties to seven years for offshore properties.

Net capitalized costs are limited to the estimated future net revenues, discounted at 10% per annum, from proved oil, natural gas and NGL reserves plus the cost of properties not subject to amortization. Estimated future net revenues exclude future cash outflows associated with settling asset retirement obligations included in the net book value of oil and gas properties. Such limitations are imposed separately on a country-by-country basis and are tested quarterly. Capitalized costs are depleted by an equivalent unit-of-production method, converting gas to oil at the ratio of six thousand cubic feet of natural gas to one barrel of oil. Depletion is calculated using the capitalized costs, including estimated asset retirement costs, plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, net of estimated salvage values. No gain or loss is recognized upon disposal of oil and gas properties unless such disposal significantly alters the relationship between capitalized costs and proved reserves in a particular country. All costs related to production activities, including workover costs incurred solely to maintain or increase levels of production from an existing completion interval, are charged to expense as incurred.

Depreciation of midstream pipelines are provided on a units-of-production basis. Depreciation and amortization of other property and equipment, including corporate and other midstream assets and leasehold improvements, are provided using the straight-line method based on estimated useful lives from three to 39 years.

Effective January 1, 2003, Devon adopted Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143") using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation. SFAS No. 143 requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms, and natural gas processing plants. The obligations included within the scope of SFAS No. 143 are those for which a company faces a legal obligation. The initial measurement of the asset retirement obligation is to record a separate liability at its fair value with an offsetting asset retirement cost recorded as an increase to the related property and equipment on the consolidated balance sheet. The asset retirement cost is depreciated using a systematic and rational method similar to that used for the associated property and equipment.

Devon had previously estimated costs of dismantlement, removal, site reclamation, and other similar activities in the total costs that were subject to depreciation, depletion, and amortization. However, Devon did not record a separate asset or liability for such amounts. Upon adoption, Devon recorded a cumulative-effect-type adjustment for an increase to net earnings of $16 million net of deferred taxes of $10 million. Additionally, Devon established an asset retirement obligation of $453 million, an increase to property and equipment of $400 million and a decrease in accumulated DD&A of $79 million.

In September 2004, the SEC issued Staff Accounting Bulletin No. 106 ("SAB No. 106") to provide guidance regarding the interaction of SFAS No. 143 with the full cost method of accounting for oil and gas properties. Specifically, SAB No. 106 clarifies the manner in which the full cost ceiling test and depletion of oil and gas properties should be calculated in accordance with the provisions of SFAS No. 143. Devon adopted SAB No. 106 prospectively in the fourth quarter of 2004. However, this adoption has not materially impacted the full cost ceiling test calculation or depletion since adoption.

Short-Term Investments and Other Marketable Securities

Devon reports its short-term investments and other marketable securities at fair value, except for debt securities in which management has the ability and intent to hold until maturity. At December 31, 2005 and 2004, Devon's short-term investments consisted of $680 million and $967 million, respectively, of auction rate securities classified as available for sale. Although Devon's auction rate securities have contractual maturities of more than 10 years, the underlying interest rates on such securities reset at intervals ranging from seven to 90 days. Therefore, these auction rate securities are priced and subsequently trade as short-term investments because of the interest rate reset feature. As a result, Devon has classified its auction rate securities as short-term investments in the accompanying consolidated balance sheet.

Devon's only other significant investment security is its investment in approximately 14.2 million shares of Chevron Corporation ("Chevron") common stock which is reported at fair value. Except for unrealized losses that are determined to be "other than temporary", the tax effected unrealized gain or loss on the investment in Chevron common stock is recognized in other comprehensive income (loss) and reported as a separate component of stockholders' equity.

Goodwill

Goodwill represents the excess of the purchase price of business combinations over the fair value of the net assets acquired and is tested for impairment at least annually. The impairment test requires allocating goodwill and all other assets and liabilities to assigned reporting units. The fair value of each reporting unit is estimated and compared to the net book value of the reporting unit. If the estimated fair value of the reporting unit is less than the net book value, including goodwill, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense. Because quoted market prices are not available for Devon's reporting units, the fair values of the reporting units are estimated based upon several valuation analyses, including comparable companies, comparable transactions and premiums paid. Devon performed annual impairment tests of goodwill in the fourth quarters of 2005, 2004 and 2003. Based on these assessments, no impairment of goodwill was required.

The table below provides a summary of Devon's goodwill, by assigned reporting unit, as of December 31, 2005 and 2004:

	DECEMBER 31, 2005	DECEMBER 31, 2004
	(IN MILLIONS)	
United States	$ 3,056	3,061
Canada	2,581	2,508
International	68	68
Total	$ 5,705	5,637

Revenue Recognition and Gas Balancing

Oil, gas and NGL revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectibility of the revenue is probable. Delivery occurs and title is transferred when production has been delivered to a pipeline or truck or a tanker lifting has occurred. Cash received relating to future production is deferred and recognized when all revenue recognition criteria are met.

Devon follows the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which Devon is entitled based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under produced owner to recoup its entitled share through production. If an imbalance exists at the time the wells' reserves are depleted, settlements are made among the joint interest owners under a variety of arrangements. The liability is priced based on current market prices. No receivables are recorded for those wells where Devon has taken less than its share of production unless all revenue recognition criteria are met.

Marketing and midstream revenues are recorded at the time products are sold or services are provided to third parties at a fixed or determinable price, when delivery or performance has occurred and title has transferred, and if collectibility of the revenue is probable. Revenues and expenses attributable to Devon's gas and NGL purchase and processing contracts are reported on a gross basis since Devon takes title to the products and has risks and rewards of ownership. The gas purchased under these contracts is processed in Devon-owned plants.

Major Purchasers

No purchaser accounted for over 10% of revenues in 2005, 2004 and 2003.

Derivative Instruments

Historically, Devon has entered into oil and gas financial instruments to manage its exposure to oil and gas price volatility. Devon has also entered into interest rate swaps to manage its exposure to interest rate volatility. The interest rate swaps mitigate either the effects of interest rate fluctuations on interest expense for variable-rate debt instruments, or the debt fair values for fixed-rate debt. At December 31, 2005, the only derivative financial instruments outstanding consisted of interest rate swaps.

All derivatives are recognized as fair value of financial instruments on the consolidated balance sheets at their fair value. Prior to December 31, 2005, a substantial portion of Devon's derivatives consisted of contracts that hedged the price of future oil and natural gas production. At inception, these derivative contracts were cash flow hedges that qualified for hedge accounting treatment. Therefore, while fair values of such hedging instruments must be estimated as of the end of each reporting period, the changes in the fair values attributable to the effective portion of these hedging instruments are not included in Devon's consolidated results of operations. Instead, the changes in fair value of the effective portion of these hedging instruments, net of tax, are recorded directly to accumulated other comprehensive income, a component of stockholders' equity, until the hedged oil or natural gas quantities are produced. The ineffective portion of these hedging instruments is included in consolidated results of operations as change in fair value of derivative financial instruments.

To qualify for hedge accounting treatment, Devon designates its cash flow hedge instruments as such on the date the derivative contract is entered into or the date of a business combination which includes cash flow hedge instruments. Additionally, Devon documents all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. Devon also assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. If Devon fails to meet the requirements for using hedge accounting, changes in fair value of these hedging instruments would not be recorded directly to equity but in the consolidated results of operations. During 2004 and 2003, no derivatives ceased to qualify for hedge accounting.

In the third quarter of 2005, certain oil derivatives ceased to qualify for hedge accounting primarily as a result of deferred production caused by hurricanes in the Gulf of Mexico. Because these contracts no longer qualified for hedge accounting, Devon recognized $39 million in losses as change in fair value of derivative financial instruments in the accompanying statement of operations.

In the first half of 2005, Devon recognized a $55 million loss related to certain oil hedges that no longer qualified for hedge accounting due to the property divestiture program. These commodity instruments related to 5,000 barrels per day of U.S. oil production and 3,000 barrels per day of Canadian oil production from properties that were sold as part of Devon's divestiture program. This loss is presented in other income in the statement on operations.

By using derivative instruments to hedge exposures to changes in commodity prices and interest rates, Devon exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are placed with counterparties that Devon believes are minimal credit risks. It is Devon's policy to enter into derivative contracts only with investment grade rated counterparties deemed by management to be competent and competitive market makers.

Market risk is the change in the value of a derivative instrument that results from a change in commodity prices or interest rates. The market risk associated with commodity price and interest rate contracts is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken. The oil and gas reference prices upon which the commodity hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by Devon. Devon does not hold or issue derivative instruments for speculative trading purposes.

During 2005, 2004 and 2003, Devon recorded in its statements of operations losses of $94 million and $62 million and a gain of $1 million, respectively, for the change in the fair value of derivative instruments that do not qualify for hedge accounting treatment, as well as the ineffectiveness of derivatives that do qualify as hedges.

Common Stock

On September 27, 2004, Devon declared a two-for-one stock split, effected in the form of a stock dividend, to stockholders of record on October 29, 2004. Common stock shares and per share amounts prior to 2004 have been restated to reflect this two-for-one stock split.

Stock Options

Devon applies the intrinsic value-based method of accounting prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations, in accounting for its fixed plan stock options. As such, compensation expense is recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price. SFAS No. 123, *Accounting for Stock-Based Compensation*, ("SFAS No. 123") established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation plans. As allowed by SFAS No. 123, Devon has elected to continue to apply the intrinsic value-based method of accounting described above, and has adopted the disclosure requirements of SFAS No. 123.

Had Devon elected the fair value provisions of SFAS No. 123 and recognized compensation expense over the vesting period based on the fair value of the stock options granted as of their grant date, Devon's 2005, 2004 and 2003 pro forma net earnings and pro forma net earnings per share would have differed from the amounts actually reported as shown in the following table.

		YEAR ENDED DECEMBER 31,		
		2005	2004	2003
		(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)		
Net earnings available to common stockholders, as reported	$	2,920	2,176	1,737
Add stock-based employee compensation expense included in reported net earnings, net of related tax expense		18	7	2
Deduct total stock-based employee compensation expense determined under fair value based method for all awards (see note 9), net of related tax expense		(44)	(31)	(23)
Net earnings available to common stockholders, pro forma	$	2,894	2,152	1,716
Net earnings per share available to common stockholders:				
As reported:				
Basic	$	6.38	4.51	4.16
Diluted	$	6.26	4.38	4.04
Pro forma:				
Basic	$	6.32	4.46	4.11
Diluted	$	6.21	4.33	3.99

The weighted average fair values of stock options granted during 2005, 2004 and 2003 were $19.65, $10.32 and $8.14, respectively. The fair value of each option grant was estimated for disclosure purposes on the date of grant using the Black-Scholes Option Pricing Model with the following assumptions for 2005, 2004 and 2003, respectively: risk-free interest rates of 4.4%, 3.2% and 2.8%; dividend yields of 0.6%, 0.5% and 0.4%; expected lives of four, four and four years; and volatility of the price of the underlying common stock of 31.0%, 32.2% and 37.9%.

Income Taxes

Devon accounts for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases, as well as the future tax consequences attributable to the future utilization of existing tax net operating loss and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. At December 31, 2005, undistributed earnings of foreign subsidiaries were determined to be permanently reinvested. Therefore, no U.S. deferred income taxes were provided on such amounts at December 31, 2005.

In October 2004, Congress enacted new tax legislation allowing qualifying corporations to repatriate cash from foreign operations at a reduced income tax rate. In 2005, Devon repatriated $545 million, substantially all of which was from Canadian operations and was taxed at the reduced income tax rate. As a result, Devon recognized approximately $28 million of additional current income tax expense. In addition, this tax legislation creates a new U.S. tax deduction which will be phased in starting in 2005 for companies with domestic production activities, including oil and gas extraction.

General and Administrative Expenses

General and administrative expenses are reported net of amounts reimbursed by working interest owners of the oil and gas properties operated by Devon and net of amounts capitalized pursuant to the full cost method of accounting.

Net Earnings Per Common Share

Basic earnings per share is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflects the potential dilution that could occur if Devon's dilutive outstanding stock options were exercised (calculated using the treasury stock method), if the previously outstanding preferred stock of a subsidiary were converted to common stock and if Devon's previously outstanding zero coupon convertible senior debentures were converted to common stock.

The following table reconciles the net earnings and common shares outstanding used in the calculations of basic and diluted earnings per share for 2005, 2004 and 2003.

	NET EARNINGS APPLICABLE TO COMMON STOCKHOLDERS	WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	NET EARNINGS PER SHARE
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)		
YEAR ENDED DECEMBER 31, 2005:			
Basic earnings per share	$ 2,920	458	$ 6.38
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	8	
Dilutive effect of potential common shares issuable upon conversion of senior convertible debentures (the increase in net earnings is net of income tax expense of $14 million) (1)	24	4	
Diluted earnings per share	$ 2,944	470	$ 6.26
YEAR ENDED DECEMBER 31, 2004:			
Basic earnings per share	$ 2,176	482	$ 4.51
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	8	
Dilutive effect of potential common shares issuable upon conversion of senior convertible debentures (the increase in net earnings is net of income tax expense of $6 million)	10	9	
Diluted earnings per share	$ 2,186	499	$ 4.38
YEAR ENDED DECEMBER 31, 2003:			
Basic earnings per share	$ 1,737	417	$ 4.16
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	6	
Dilutive effect of potential common shares issuable upon conversion of preferred stock of subsidiary acquired in 2003 merger	2	1	
Dilutive effect of potential common shares issuable upon conversion of senior convertible debentures (the increase in net earnings is net of income tax expense of $6 million)	9	9	
Diluted earnings per share	$ 1,748	433	$ 4.04

(1) The senior convertible debentures were retired in June 2005 prior to their stated maturity.

Certain options to purchase shares of Devon's common stock have been excluded from the dilution calculations because the options' exercise price exceeded the average market price of Devon's common stock during the applicable year. The following information relates to these options.

	2005	2004	2003
Options excluded from dilution calculation (in millions)	— (1)	4	10
Range of exercise prices	$ 56.09 - $68.64	$ 33.00 - $44.83	$ 24.96 - $44.83
Weighted average exercise price	$ 66.01	$ 38.22	$ 28.05

(1) Actual amount of options excluded from the 2005 dilution calculation are 154,000 shares.

The excluded options for 2005 expire between July 28, 2010 and December 11, 2013.

Foreign Currency Translation Adjustments

Devon's Canadian subsidiaries use the Canadian dollar as their functional currency. Therefore, the assets and liabilities of Devon's Canadian subsidiaries are translated into U.S. dollars based on the current exchange rate in effect at the balance sheet dates, while income and expenses are translated at average rates for the periods presented. Translation adjustments have no effect on net income and are included in accumulated other comprehensive income in stockholders' equity. Devon's International subsidiaries use the U.S. dollar as their functional currency.

Statements of Cash Flows

For purposes of the consolidated statements of cash flows, Devon considers all highly liquid investments with original contractual maturities of three months or less to be cash equivalents.

Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Environmental expenditures are expensed or capitalized in accordance with accounting principles generally accepted in the United States of America. Liabilities for these expenditures are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Reference is made to note 12 for a discussion of amounts recorded for these liabilities.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current year presentation.

Recently Issued Accounting Standards Not Yet Adopted

In December 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123(R), "Share-Based Payment", ("SFAS No. 123(R)") which is a revision of SFAS No. 123 and supersedes APB Opinion No. 25 regarding stock-based employee compensation plans. APB Opinion No. 25 requires recognition of compensation expense only if the current market price of the underlying stock exceeded the stock option exercise price on the date of grant. Additionally, SFAS No. 123 established fair value-based accounting for stock-based employee compensation plans but allowed pro forma disclosure as an alternative to financial statement recognition. SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, to be valued at fair value on the date of grant, and to be expensed over the applicable vesting period. Also, pro forma disclosure of the income statement effects of share-based payments is no longer an alternative. Devon will adopt the provisions of SFAS No. 123(R) in the first quarter of 2006 using the modified prospective method. Under this method, Devon will recognize compensation expense for all stock-based awards granted or modified on or after January 1, 2006, as well as any previously granted awards that are not fully vested as of January 1, 2006. Compensation expense will be measured based on the fair value of the awards previously calculated in developing the pro forma disclosures in accordance with the provisions of SFAS No. 123. Based on our current estimates of the amount of 2006 stock option grants and the various assumptions used to estimate the fair value of these stock option grants, we expect stock option expense, net of related capitalization in accordance with the full cost method of accounting for oil and gas properties, will be approximately $35 million. No retroactive or cumulative effect adjustments will be recorded upon adoption.

2. BUSINESS COMBINATIONS AND PRO FORMA INFORMATION

Ocean Energy, Inc.

On April 25, 2003, Devon completed its merger with Ocean Energy, Inc. ("Ocean"). In the transaction, Devon issued 0.828 shares of its common stock for each outstanding share of Ocean common stock (or a total of approximately 148 million shares). Also, Devon assumed approximately $1.8 billion of debt (current and long-term) from Ocean.

Devon acquired Ocean primarily for the significant production, development projects and exploration prospects in both the deepwater Gulf of Mexico and internationally, and the additional producing assets onshore in the United States and in the shallower shelf regions of the Gulf of Mexico.

The calculation of the purchase price and the allocation to assets and liabilities are shown below.

	(IN MILLIONS, EXCEPT SHARE PRICE)
Calculation and allocation of purchase price:	
Shares of Devon common stock issued to Ocean stockholders	148
Average Devon stock price	$ 24.03
Fair value of common stock issued	$ 3,546
Plus merger costs incurred	114
Plus fair value of Ocean convertible preferred stock assumed by a Devon subsidiary	64
Plus fair value of Ocean employee stock options assumed by Devon	124
Total purchase price	3,848
Plus fair value of liabilities assumed by Devon:	
Current liabilities	650
Long-term debt	1,436
Deferred revenue	97
Asset retirement obligation, long-term	121
Other noncurrent liabilities	89
Deferred income taxes	954
Total purchase price plus liabilities assumed	$ 7,195
Fair value of assets acquired by Devon:	
Current assets	$ 256
Proved oil and gas properties	4,262
Unproved oil and gas properties	1,060
Other property and equipment	85
Other noncurrent assets	39
Goodwill (none deductible for income taxes)	1,493
Total fair value of assets acquired	$ 7,195

Pro Forma Information

Set forth in the following table is certain unaudited pro forma financial information for the year ended December 31, 2003. The information has been prepared assuming the Ocean merger was consummated on January 1, 2003. All pro forma information is based on estimates and assumptions deemed appropriate by Devon. The pro forma information is presented for illustrative purposes only. If the transactions had occurred in the past, Devon's operating results might have been different from those presented in the following table. The pro forma information should not be relied upon as an indication of the operating results that Devon would have achieved if the transactions had occurred on January 1, 2003. The pro forma information also should not be used as an indication of future results.

	PRO FORMA INFORMATION YEAR ENDED DECEMBER 31, 2003
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS AND PRODUCTION VOLUMES) (UNAUDITED)
REVENUES:	
Oil sales	$ 1,840
Gas sales	4,155
NGL sales	416
Marketing and midstream revenues	1,461
Total revenues	7,872
EXPENSES AND OTHER INCOME, NET:	
Lease operating expenses	1,167
Production taxes	219
Marketing and midstream operating costs and expenses	1,174
Depreciation, depletion and amortization of oil and gas properties	1,859
Depreciation and amortization of non-oil and gas properties	125
Accretion of asset retirement obligation	38
General and administrative expenses	340
Interest expense	515
Effects of changes in foreign currency exchange rates	(69)
Change in fair value of derivative financial instruments	(1)
Reduction of carrying value of oil and gas properties	111
Other income, net	(37)
Total expenses and other income, net	5,441
Earnings before income taxes and cumulative effect of change in accounting principle	2,431
INCOME TAX EXPENSE:	
Current	219
Deferred	372
Total income tax expense	591
Earnings before cumulative effect of change in accounting principle	1,840
Cumulative effect of change in accounting principle, net of tax	29
Net earnings	1,869
Preferred stock dividends	10
Net earnings applicable to common stockholders	$ 1,859
BASIC EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING:	
Earnings before cumulative effect of change in accounting principle	$ 3.95
Cumulative effect of change in accounting principle, net of tax	0.06
Net earnings	$ 4.01
DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING:	
Earnings before cumulative effect of change in accounting principle	$ 3.83
Cumulative effect of change in accounting principle, net of tax	0.06
Net earnings	$ 3.89
Weighted average common shares outstanding — basic	463
Weighted average common shares outstanding — diluted	481
PRODUCTION VOLUMES:	
Oil (MMBbls)	72
Gas (Bcf)	913
NGLs (MMBbls)	23
MMBoe	247

3. COMPREHENSIVE INCOME OR LOSS

Devon's comprehensive income or loss information is included in the accompanying consolidated statements of stockholders' equity and comprehensive income (loss). A summary of accumulated other comprehensive income or loss as of December 31, 2005, 2004 and 2003, and changes during each of the years then ended, is presented in the following table.

		Foreign Currency Translation Adjustments	Change in Fair Value of Derivative Instruments	Minimum Pension Liability Adjustments	Unrealized Gain on Marketable Securities	Total
				(In millions)		
BALANCE AS OF DECEMBER 31, 2002	$	(99)	(97)	(71)	—	(267)
2003 activity		894	(41)	28	141	1,022
Deferred taxes		(128)	3	(9)	(52)	(186)
2003 activity, net of deferred taxes		766	(38)	19	89	836
BALANCE AS OF DECEMBER 31, 2003		667	(135)	(52)	89	569
2004 activity		426	(213)	61	132	406
Deferred taxes		(38)	62	(22)	(47)	(45)
2004 activity, net of deferred taxes		388	(151)	39	85	361
BALANCE AS OF DECEMBER 31, 2004		1,055	(286)	(13)	174	930
2005 activity		181	430	(8)	60	663
Deferred taxes		(19)	(141)	3	(22)	(179)
2005 activity, net of deferred taxes		162	289	(5)	38	484
BALANCE AS OF DECEMBER 31, 2005	$	1,217	3	(18)	212	1,414

4. SUPPLEMENTAL CASH FLOW INFORMATION

Cash payments for interest and income taxes in 2005, 2004 and 2003 are presented below:

		Year Ended December 31,		
		2005	2004	2003
			(In millions)	
Interest paid	$	663	474	508
Income taxes paid	$	1,092	477	123

The 2003 Ocean merger involved non-cash consideration as presented below:

		Ocean Merger
		(In millions)
Value of common stock issued	$	3,546
Convertible preferred stock assumed		64
Employee stock options assumed		124
Liabilities assumed		2,393
Deferred tax liability created		954
Fair value of assets acquired with non-cash consideration	$	7,081

5. ACCOUNTS RECEIVABLE

The components of accounts receivable include the following:

		December 31,	
		2005	2004
		(In millions)	
Oil, gas and NGL revenue	$	1,149	946
Joint interest billings		206	159
Marketing and midstream revenue		173	162
Other		78	60
		1,606	1,327
Allowance for doubtful accounts		(5)	(7)
Net accounts receivable	$	1,601	1,320

6. PROPERTY AND EQUIPMENT AND ASSET RETIREMENT OBLIGATIONS

Property and equipment included the following:

	December 31, 2005	December 31, 2004
	(In millions)	
Oil and gas properties:		
Subject to amortization	$ 29,631	27,257
Not subject to amortization	2,747	3,187
Accumulated depreciation, depletion and amortization	(14,598)	(12,410)
Net oil and gas properties	17,780	18,034
Other property and equipment	1,868	1,670
Accumulated depreciation and amortization	(516)	(358)
Net other property and equipment	1,352	1,312
Property and equipment, net of accumulated depreciation, depletion and amortization	$ 19,132	19,346

The costs not subject to amortization relate to unproved properties which are excluded from amortized capital costs until it is determined whether or not proved reserves can be assigned to such properties. The excluded properties are assessed for impairment quarterly. Subject to industry conditions, evaluation of most of these properties, and the inclusion of their costs in the amortized capital costs is expected to be completed within five years.

The following is a summary of Devon's oil and gas properties not subject to amortization as of December 31, 2005:

	Costs incurred in 2005	2004	2003	Prior to 2003	Total
			(In millions)		
Acquisition costs	$ 334	134	467	950	1,885
Exploration costs	330	172	120	30	652
Development costs	19	—	44	—	63
Capitalized interest	60	54	32	1	147
Total oil and gas properties costs not subject to amortization	$ 743	360	663	981	2,747

At December 31, 2005, Devon's investment in countries where proved reserves have not been established was $232 million. This amount included $116 million in Nigeria, $113 million in Brazil and $3 million in Ghana.

In September 2004, Devon announced its plans to divest certain non-core oil and gas properties in the offshore Gulf of Mexico and onshore in the United States and Canada. During 2005, Devon closed all such property divestitures and received $2.0 billion of gross proceeds, net of all purchase price adjustments. After-tax, the proceeds are approximately $1.8 billion. Certain information regarding these sales is included in the following table.

	United States	Canada	Total
		($ in millions)	
Gross proceeds	$ 966	1,029	1,995
After-tax proceeds	$ 786	1,027	1,813
Asset retirement obligations assumed by purchasers	$ 160	39	199
Reserves sold (MMBoe)	89	87	176

Under full cost accounting rules, a gain or loss on the sale or other disposition of oil and gas properties is not recognized unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. Because the divestitures that closed in 2005 did not significantly alter such relationship, Devon did not recognize a gain or loss on these divestitures. Therefore, the proceeds from these transactions were recognized as an adjustment of capitalized costs in the respective cost centers.

As described in Note 1, effective January 1, 2003, Devon adopted SFAS No. 143 and began recording asset retirement obligations for estimated property and equipment dismantlement, abandonment and restoration costs when a legal obligation is incurred. In accordance with SFAS No. 143, oil and gas properties subject to amortization and other property and equipment listed above include asset retirement costs associated with these asset retirement obligations. Following is a reconciliation of the asset retirement obligation for the years ended December 31, 2005 and 2004.

	YEAR ENDED DECEMBER 31, 2005	2004
	(IN MILLIONS)	
Asset retirement obligation as of beginning of year	$ 739	671
Liabilities incurred	119	51
Liabilities settled	(42)	(42)
Liabilities assumed by others	(199)	(4)
Accretion expense on discounted obligation	44	44
Foreign currency translation adjustment	7	19
Asset retirement obligation as of end of year	668	739
Less current portion	50	46
Asset retirement obligation, long-term	$ 618	693

7. LONG-TERM DEBT AND RELATED EXPENSES

A summary of Devon's long-term debt is as follows:

	DECEMBER 31, 2005	2004
	(IN MILLIONS)	
Debentures exchangeable into shares of Chevron Corporation common stock:		
4.90% due August 15, 2008	$ 444	444
4.95% due August 15, 2008	316	316
Discount on exchangeable debentures	(51)	(68)
Zero coupon convertible senior debentures exchangeable into shares of Devon common stock, due June 27, 2020 (retired in 2005)	—	419
Other debentures and notes:		
7.625% due July 1, 2005	—	125
7.25% due July 18, 2005 ($175 million Canadian)	—	145
10.25% due November 1, 2005	—	236
2.75% due August 1, 2006	500	500
6.55% due August 2, 2006 ($200 million Canadian)	172	166
4.375% due October 1, 2007	400	400
10.125% due November 15, 2009	177	177
6.75% due March 15, 2011 (retired in 2005)	—	400
6.875% due September 30, 2011	1,750	1,750
7.25% due October 1, 2011	350	350
8.25% due July 1, 2018	125	125
7.50% due September 15, 2027	150	150
7.875% due September 30, 2031	1,250	1,250
7.95% due April 15, 2032	1,000	1,000
Other	3	3
Fair value adjustment on debt related to interest rate swaps	(18)	9
Net premium on other debentures and notes	51	67
	6,619	7,964
Less amount classified as current	662	933
Long-term debt	$ 5,957	7,031

Maturities of long-term debt as of December 31, 2005, excluding the $18 million fair value adjustment, are as follows (in millions):

2006	$ 673
2007	400
2008	762
2009	177
2010	—
2011 and thereafter	4,625
Total	$ 6,637

Credit Facilities with Banks

Devon has a $1.5 billion five-year, syndicated, unsecured revolving line of credit (the "Senior Credit Facility"). The Senior Credit Facility includes (i) a five-year revolving Canadian subfacility in a maximum amount of U.S. $500 million and (ii) a $1 billion sublimit for the issuance of letters of credit, including letters of credit under the Canadian subfacility.

The Senior Credit Facility matures on April 8, 2010, and all amounts outstanding will be due and payable at that time unless the maturity is extended. Prior to each April 8 anniversary date, Devon has the option to extend the maturity of the Senior Credit Facility for one year, subject to the approval of the lenders. Devon is working to obtain lender approval to extend the current maturity date of April 8, 2010 to April 8, 2011. If successful, this maturity date extension will be effective on April 7, 2006, provided Devon has not experienced a "material adverse effect," as defined in the Senior Credit Facility agreement, at that date.

Amounts borrowed under the Senior Credit Facility may, at the election of Devon, bear interest at various fixed rate options for periods of up to twelve months. Such rates are generally less than the prime rate. Devon may also elect to borrow at the prime rate. The Senior Credit Facility currently provides for an annual facility fee of $1.9 million that is payable quarterly in arrears.

The agreement governing the Senior Credit Facility contains certain covenants and restrictions, including a maximum allowed debt-to-capitalization ratio of 65% as defined in the agreement. At December 31, 2005, Devon was in compliance with such covenants and restrictions. Devon's debt-to-capitalization ratio at December 31, 2005, as calculated pursuant to the terms of the agreement, was 27.0%.

As of December 31, 2005, there were no borrowings under the Senior Credit Facility. The available capacity under the Senior Credit Facility as of December 31, 2005, net of $310 million of outstanding letters of credit, was approximately $1.2 billion.

Commercial Paper

Devon also has a commercial paper program under which it may borrow up to $725 million. Borrowings under the commercial paper program reduce available capacity under the Senior Credit Facility on a dollar-for-dollar basis. The commercial paper borrowings may have terms of up to 365 days and bear interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, London Interbank Offered Rate (LIBOR), or the money market rate as found on the commercial paper market. As of December 31, 2005 and 2004, Devon had no commercial paper debt outstanding.

Exchangeable Debentures

The exchangeable debentures consist of $444 million of 4.90% debentures and $316 million of 4.95% debentures. The exchangeable debentures were issued on August 3, 1998 and mature August 15, 2008. The exchangeable debentures were callable beginning August 15, 2000, initially at 104.0% of principal and at prices declining to 100.5% of principal on or after August 15, 2007. At December 31, 2005, the call price was 101.5% of principal. The exchangeable debentures are exchangeable at the option of the holders at any time prior to maturity, unless previously redeemed, for shares of Chevron common stock. In lieu of delivering Chevron common stock to an exchanging debenture holder, Devon may, at its option, pay to such holder an amount of cash equal to the market value of the Chevron common stock. At maturity, holders who have not exercised their exchange rights will receive an amount in cash equal to the principal amount of the debentures.

As of December 31, 2005, Devon beneficially owned approximately 14.2 million shares of Chevron common stock. These shares have been deposited with an exchange agent for possible exchange for the exchangeable debentures. Each $1,000 principal amount of the exchangeable debentures is exchangeable into 18.6566 shares of Chevron common stock, an exchange rate equivalent to $53.60 per share of Chevron stock.

The exchangeable debentures were assumed as part of the PennzEnergy merger. The fair values of the exchangeable debentures were determined as of August 17, 1999, based on market quotations. In accordance with derivative accounting standards, the total fair value of the debentures has been allocated between the interest-bearing debt and the option to exchange Chevron common stock that is embedded in the debentures. Accordingly, a discount was recorded on the debentures and is being accreted using the effective interest method which raised the effective interest rate on the debentures to 7.76%.

Zero Coupon Convertible Debentures

In June 2005, Devon redeemed the zero coupon convertible debentures prior to their scheduled maturity of June 27, 2020. Devon's obligation to settle the conversions and redeem the debentures totaled $452 million and was satisfied with cash on hand. The total cash payments to settle the conversions and redeem the debentures exceeded the accreted value of the debentures by $25 million. This $25 million, as well as $5 million of unamortized issuance costs, are included in interest expense in the accompanying 2005 statements of operations. The after-tax effect of these expenses was $19 million.

Other Debentures and Notes

Following are descriptions of the various other debentures and notes outstanding at December 31, 2005, as listed in the table presented at the beginning of this note.

Ocean Debt In connection with the Ocean merger, Devon assumed $1.8 billion of debt. The table below summarizes the debt assumed which remains outstanding, the fair value of the debt at April 25, 2003, and the effective interest rate of the debt assumed after determining the fair values of the respective notes using April 25, 2003, market interest rates. The premiums are being amortized using the effective interest method. All of the notes are general unsecured obligations of Devon.

DEBT ASSUMED	FAIR VALUE OF DEBT ASSUMED (IN MILLIONS)	EFFECTIVE RATE OF DEBT ASSUMED
4.375% due October 2007 (principal of $400 million)	$ 410	3.8%
7.250% due October 2011 (principal of $350 million)	$ 406	4.9%
8.250% due July 2018 (principal of $125 million)	$ 147	5.5%
7.500% due September 2027 (principal of $150 million)	$ 169	6.5%

Anderson Debt In connection with the Anderson acquisition, Devon assumed $702 million of senior notes. The table below summarizes the debt assumed which remains outstanding, the fair value of the debt at October 15, 2001, and the effective interest rate of the debt assumed after determining the fair values of the respective notes using October 15, 2001, market interest rates. The premium is being amortized using the effective interest method. The senior notes are general unsecured obligations of Devon.

DEBT ASSUMED	FAIR VALUE OF DEBT ASSUMED (IN MILLIONS)	EFFECTIVE RATE OF DEBT ASSUMED
6.55% senior notes due 2006 (principal of $200 million Canadian)	$ 129	6.5%

2.75% Notes due August 1, 2006 On August 4, 2003, Devon issued these notes which are unsecured and unsubordinated obligations of Devon. The proceeds from the issuance of these debt securities, net of discounts and issuance costs, of $498 million were used to repay amounts outstanding under Devon's $3 billion term loan credit facility.

10.125% Debentures due November 15, 2009 These debentures were assumed as part of the PennzEnergy acquisition. The fair value of the debentures was determined using August 17, 1999, market interest rates. As a result, premiums were recorded on these debentures which lowered their effective interest rate to 8.9%. The premium is being amortized using the effective interest method.

6.875% Notes due September 30, 2011 and 7.875% Debentures due September 30, 2031 On October 3, 2001, Devon, through Devon Financing Corporation, U.L.C. ("Devon Financing"), sold these notes and debentures which are unsecured and unsubordinated obligations of Devon Financing. Devon has fully and unconditionally guaranteed on an unsecured and unsubordinated basis the obligations of Devon Financing under the debt securities. The proceeds from the issuance of these debt securities were used to fund a portion of the Anderson acquisition. The $3 billion of debt securities were structured in a manner that results in an expected weighted average after-tax borrowing rate of approximately 1.65%.

7.95% Notes due April 15, 2032 On March 25, 2002, Devon sold these notes which are unsecured and unsubordinated obligations of Devon. The net proceeds received, after discounts and issuance costs, were $986 million and were partially used to pay down $820 million on Devon's $3 billion term loan credit facility. The remaining $166 million of net proceeds was used in June 2002 to partially fund the early extinguishment of $175 million of 8.75% senior subordinated notes due June 15, 2007.

$400 million 6.75% Senior Notes due March 15, 2011 On September 12, 2005, Devon redeemed the $400 million 6.75% notes due 2011, using cash on hand. Devon incurred a $51 million premium in conjunction with the early retirement. The $51 million premium is included in interest expense in the accompanying 2005 statement of operations. The after-tax effect of the $51 million premium was $34 million.

Interest Expense

Following are the components of interest expense for the years 2005, 2004 and 2003:

	Year Ended December 31,		
	2005	2004	2003
	(In millions)		
Interest based on debt outstanding	$ 507	513	531
Accretion of debt discount, net	4	2	3
Facility and agency fees	2	2	1
Amortization of capitalized loan costs	7	22	12
Capitalized interest	(70)	(70)	(50)
Early retirement premiums	76	—	—
Other	7	6	5
Total interest expense	$ 533	475	502

Effects of Changes in Foreign Currency Exchange Rates

Devon had $400 million of 6.75% fixed-rate senior notes payable by one of its Canadian subsidiaries. However, the notes were denominated in U.S. dollars. Changes in the exchange rate between the U.S. dollar and the Canadian dollar from the dates the notes were assumed as part of an acquisition to the date of repayment increased or decreased the expected amount of Canadian dollars eventually required to repay the notes. Such changes in the Canadian dollar equivalent of the debt and certain cash and other working capital amounts of Devon's Canadian subsidiary which are also denominated in U.S. dollars are required to be included in determining net earnings for the period in which the exchange rate changed. Devon redeemed these notes on September 12, 2005, and, as a result of changes in the rate of conversion of Canadian dollars to U.S. dollars, $9 million, $22 million, and $69 million was recorded as a reduction of expense in 2005, 2004 and 2003, respectively.

8. INCOME TAXES

At December 31, 2005, Devon had the following net operating loss carryforwards which are available to reduce future taxable income in the jurisdiction where the net operating loss was incurred. These carryforwards will result in a future tax reduction based upon the future tax rate applicable to the taxable income that is ultimately offset by the net operating loss carryforward.

Jurisdiction	Years of Expiration	Carryforward Amounts
		(In millions)
U.S. federal	2022	$ 50
Various U.S. states	2006 - 2022	$ 71
Canada	2008 - 2015	$ 356
Azerbaijan	Indefinite	$ 87

Additionally, at December 31, 2005, Devon had $18 million of U.S. minimum tax credit carryforwards which have no expiration and are available to reduce future income taxes. The net operating loss and minimum tax credit carryforward amounts have been recognized for financial purposes to reduce the net deferred tax liability at December 31, 2005.

The earnings before income taxes and the components of income tax expense (benefit) for the years 2005, 2004 and 2003 were as follows:

		YEAR ENDED DECEMBER 31,		
		2005	2004	2003
			(IN MILLIONS)	
Earnings before income taxes:				
U.S	$	3,254	2,264	1,603
Canada		899	598	603
International		399	431	39
Total	$	4,552	3,293	2,245
Current income tax expense (benefit):				
U.S. federal	$	864	473	125
Various states		26	10	6
Canada		106	49	(9)
International		242	220	71
Total current tax expense		1,238	752	193
Deferred income tax expense (benefit):				
U.S. federal		213	219	360
Various states		(18)	21	17
Canada		217	149	(16)
International		(28)	(34)	(40)
Total deferred tax expense		384	355	321
Total income tax expense	$	1,622	1,107	514

Total income tax expense differed from the amounts computed by applying the U.S. federal income tax rate to earnings before income taxes and cumulative effect of change in accounting principle as a result of the following:

		YEAR ENDED DECEMBER 31,		
		2005	2004	2003
			(IN MILLIONS)	
Expected income tax expense based on U.S. statutory tax rate of 35%	$	1,593	1,153	786
Dividends received deduction		(6)	(5)	(5)
Repatriation of Canadian earnings		28	—	—
United States manufacturing deduction		(25)	—	—
State income taxes		6	20	15
Taxation on foreign operations		30	(30)	(78)
Effect of Canadian tax rate reductions		(14)	(36)	(218)
Other		10	5	14
Total income tax expense	$	1,622	1,107	514

During 2005, Devon repatriated $545 million, substantially all of which was Canadian earnings from its Canadian subsidiary, to the U.S. which resulted in a $28 million tax effect.

In October 2004, Congress enacted new tax legislation that creates a new U.S. tax deduction which will be phased in starting in 2005 for companies with domestic production activities, including oil and gas extraction. This deduction provided a $25 million tax benefit in 2005.

During 2005, 2004 and 2003, total income tax expense was reduced by the effects of Canadian statutory rate reductions. As presented in the table above, these rate reductions resulted in $14 million, $36 million and $218 million benefits in 2005, 2004 and 2003, respectively, related to the lower tax rates being applied to deferred tax liabilities outstanding as of the beginning of the year.

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities at December 31, 2005 and 2004 are presented below:

	December 31, 2005	December 31, 2004
	(In millions)	
Deferred tax assets:		
Net operating loss carryforwards	$ 148	336
Minimum tax credit carryforwards	18	29
Fair value of derivative financial instruments	52	157
Asset retirement obligations	271	252
Pension benefit obligation	49	52
Other	102	130
Total deferred tax assets	640	956
Deferred tax liabilities:		
Property and equipment, principally due to nontaxable business combinations, differences in depreciation, and the expensing of intangible drilling costs for tax purposes	(5,437)	(5,366)
Chevron Corporation common stock	(247)	(231)
Long-term debt	(168)	(149)
Other	(35)	(10)
Total deferred tax liabilities	(5,887)	(5,756)
Net deferred tax liability	$ (5,247)	(4,800)

As shown in the above table, Devon has recognized $640 million of deferred tax assets as of December 31, 2005. Such amount includes $148 million from various carryforwards available to offset future income taxes. The carryforwards include federal net operating loss carryforwards which do not expire until 2022, state net operating loss carryforwards which expire primarily between 2006 and 2022, Canadian net operating loss carryforwards which expire primarily between 2008 and 2015, and Azerbaijani net operating loss carryforwards and U.S. minimum tax credit carryforwards which have no expiration. The tax benefits of carryforwards are recorded as an asset to the extent that management assesses the utilization of such carryforwards to be "more likely than not." When the future utilization of some portion of the carryforwards is determined not to be "more likely than not," a valuation allowance is provided to reduce the recorded tax benefits from such assets.

Devon expects the tax benefits from the net operating loss carryforwards to be utilized between 2006 and 2009. Such expectation is based upon current estimates of taxable income during this period, considering limitations on the annual utilization of these benefits as set forth by tax regulations. Significant changes in such estimates caused by variables such as future oil and gas prices or capital expenditures could alter the timing of the eventual utilization of such carryforwards. There can be no assurance that Devon will generate any specific level of continuing taxable earnings. However, management believes that Devon's future taxable income will more likely than not be sufficient to utilize substantially all its tax carryforwards prior to their expiration.

9. STOCKHOLDERS' EQUITY

The authorized capital stock of Devon consists of 800 million shares of common stock, par value $0.10 per share, and 4.5 million shares of preferred stock, par value $1.00 per share. The preferred stock may be issued in one or more series, and the terms and rights of such stock will be determined by the Board of Directors.

Effective August 17, 1999, Devon issued 1.5 million shares of 6.49% cumulative preferred stock, Series A, to holders of PennzEnergy 6.49% cumulative preferred stock, Series A. Dividends on the preferred stock are cumulative from the date of original issue and are payable quarterly, in cash, when declared by the Board of Directors. The preferred stock is redeemable at the option of Devon at any time on or after June 2, 2008, in whole or in part, at a redemption price of $100 per share, plus accrued and unpaid dividends to the redemption date.

Devon's Board of Directors has designated a certain number of shares of the preferred stock as Series A Junior Participating Preferred Stock (the "Series A Junior Preferred Stock") in connection with the adoption of the shareholder rights plan described later in this note. On April 25, 2003, the Board increased the designated shares from 2.0 million to 2.9 million. At December 31, 2005, there were no shares of Series A Junior Preferred Stock issued or outstanding. The Series A Junior Preferred Stock is entitled to receive cumulative quarterly dividends per share equal to the greater of $1.00 or 200 times the aggregate per share amount of all dividends (other than stock dividends) declared on common stock since the immediately preceding quarterly dividend payment date or, with respect to the first payment date, since the first issuance of Series A Junior Preferred Stock. Holders of the Series A Junior Preferred Stock are entitled to 200 votes per share (subject to adjustment to prevent dilution) on all matters submitted to a vote of the stockholders. The Series A Junior Preferred Stock is neither redeemable nor convertible. The Series A Junior Preferred Stock ranks prior to the common stock but junior to all other classes of Preferred Stock.

The following is a summary of the changes in Devon's common shares outstanding for 2005, 2004 and 2003:

	2005	2004	2003
		(IN MILLIONS)	
Shares outstanding, beginning of year	484	472	314
Exercise of stock options	5	13	10
Shares repurchased and retired	(47)	(5)	—
Grant of restricted stock	1	2	1
Conversion of subsidiary's preferred stock	—	2	—
Issuance of common stock	—	—	147
Shares outstanding, end of year	443	484	472

On September 27, 2004, Devon announced a stock repurchase program to repurchase up to 50 million shares of its common stock. During 2004, Devon repurchased 5 million shares at a total cost of $189 million, or $37.78 per share. This program was completed in 2005, during which Devon repurchased 44.6 million shares at a total cost of $2.1 billion, or $47.69 per share. The total cost of this program was $2.3 billion, or $46.69 per share.

On August 3, 2005, Devon announced another program to repurchase up to 50 million shares of its common stock. This second stock repurchase program is planned to extend through 2007. Shares may be purchased from time to time depending upon market conditions. Devon plans to repurchase shares in the open market and in privately negotiated transactions. This stock repurchase program may be discontinued at any time. During 2005, Devon repurchased 2.2 million shares at a cost of $134 million, or $60.16 per share, under this program.

At December 31, 2003, a subsidiary of Devon created in the Ocean merger had 38,000 shares of convertible preferred stock outstanding. In January 2004, these shares of convertible preferred stock were canceled and converted to 2,197,160 shares of Devon common stock pursuant to an automatic conversion feature of the preferred stock. The automatic conversion feature was triggered when the closing price of Devon common stock equaled or exceeded the forced conversion price of $26.20 for 20 consecutive trading days.

Equity Compensation Plans

On June 8, 2005, Devon's stockholders adopted the 2005 Long-Term Incentive Plan which expires on June 8, 2013. This plan authorizes the compensation committee, which consists of non-management members of Devon's Board of Directors, to grant nonqualified and incentive stock options, restricted stock awards, restricted stock units, performance units and performance bonuses to selected employees. The plan also authorizes the grant of nonqualified stock options and restricted stock awards to directors. A total of 32 million shares of Devon common stock have been reserved for issuance pursuant to the plan. To calculate shares issued under the plan, options granted represent one share and other awards represent 2.2 shares.

The exercise price of stock options granted under the plans may not be less than the estimated fair market value of the stock at the date of grant. Options granted under the plans are exercisable during a period established for each grant, which period may not exceed eight years from the date of grant. In addition, the grantee must pay the exercise price in cash or in common stock, or a combination thereof, at the time that the option is exercised. Restricted stock awards granted under the plans are subject to pro rata vesting over at least a three-year period. During this vesting period, the fair value of the restricted stock awards granted is recognized pro rata as general and administrative expenses.

Devon also has stock option plans that were adopted in 2003, 1997 and 1993 under which stock options and restricted stock awards were issued to key management and professional employees. Options granted under these plans remain exercisable by the employees owning such options, but no new options or restricted stock awards will be granted under these plans. Devon also has stock options outstanding that were assumed as part of the acquisitions of Ocean, Mitchell Energy & Development Corp., Santa Fe Snyder and PennzEnergy.

A summary of stock options related to each of these equity compensation plans as of December 31, 2005 is presented below:

PLAN	OPTIONS OUTSTANDING (IN THOUSANDS)
2005 Plan	2,640
2003 Plan	5,244
1997 Plan	5,937
1993 Plan	88
Ocean Energy	1,559
Mitchell Energy	240
Santa Fe Snyder	69
PennzEnergy	955
Totals	16,732

A summary of the status of Devon's stock option plans as of December 31, 2003, 2004 and 2005, and changes during each of the years then ended, is presented below.

	OPTIONS OUTSTANDING		OPTIONS EXERCISABLE	
	NUMBER OUTSTANDING (IN THOUSANDS)	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER EXERCISABLE (IN THOUSANDS)	WEIGHTED AVERAGE EXERCISE PRICE
BALANCE AT DECEMBER 31, 2002	22,461	$ 20.50	13,983	$ 20.03
Options granted	3,008	$ 26.38		
Options assumed in the Ocean merger	15,852	$ 19.84		
Options exercised	(9,732)	$ 16.75		
Options forfeited	(899)	$ 26.10		
BALANCE AT DECEMBER 31, 2003	30,690	$ 21.76	22,920	$ 21.30
Options granted	3,176	$ 37.76		
Options exercised	(13,479)	$ 19.84		
Options forfeited	(612)	$ 24.96		
BALANCE AT DECEMBER 31, 2004	19,775	$ 25.54	13,027	$ 23.27
Options granted	2,705	$ 65.63		
Options exercised	(5,446)	$ 23.02		
Options forfeited	(302)	$ 31.34		
BALANCE AT DECEMBER 31, 2005	16,732	$ 32.74	10,915	$ 25.04

The following table summarizes information about Devon's stock options which were outstanding, and those which were exercisable, as of December 31, 2005.

	OPTIONS OUTSTANDING			OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICES	NUMBER OUTSTANDING (IN THOUSANDS)	WEIGHTED AVERAGE REMAINING LIFE	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER EXERCISABLE (IN THOUSANDS)	WEIGHTED AVERAGE EXERCISE PRICE
$ 5.14 - $23.04	3,597	4.28 Years	$ 17.58	3,597	$ 17.58
$23.05 - $26.25	4,153	5.33 Years	$ 23.83	3,631	$ 23.94
$26.43 - $37.39	3,436	3.51 Years	$ 28.65	2,443	$ 29.21
$38.45 - $62.54	2,975	4.65 Years	$ 39.14	1,123	$ 38.97
$66.39 - $68.64	2,571	5.65 Years	$ 66.41	121	$ 66.45
	16,732	4.66 Years	$ 32.74	10,915	$ 25.04

A summary of restricted stock awards granted under each of these equity compensation plans as of December 31, 2005 is presented below:

	2005	2004	2003	TOTAL
	(SHARES IN THOUSANDS, $ IN MILLIONS, EXCEPT PER SHARE AMOUNTS)			
2005 Plan				
Shares granted	1,274	—	—	1,274
Aggregate fair value	$ 84	—	—	$ 84
Weighted average fair value per share	$ 65.98	—	—	$ 65.98
2003 Plan				
Shares granted	30	1,735	1,306	3,071
Aggregate fair value	$ 1	$ 66	$ 34	$ 101
Weighted average fair value per share	$ 45.95	$ 38.24	$ 26.41	$ 33.29
Total				
Shares granted	1,304	1,735	1,306	4,345
Aggregate fair value	$ 85	$ 66	$ 34	$ 185
Weighted average fair value per share	$ 65.51	$ 38.24	$ 26.41	$ 42.87

Shareholder Rights Plan

Under Devon's shareholder rights plan, stockholders have one half of one right for each share of common stock held. The rights become exercisable and separately transferable ten business days after (a) an announcement that a person has acquired, or obtained the right to acquire, 15% or more of the voting shares outstanding, or (b) commencement of a tender or exchange offer that could result in a person owning 15% or more of the voting shares outstanding.

Each right entitles its holder (except a holder who is the acquiring person) to purchase either (a) 1/100 of a share of Series A Preferred Stock for $185.00, subject to adjustment or, (b) Devon common stock with a value equal to twice the exercise price of the right, subject to adjustment to prevent dilution. In the event of certain merger or asset sale transactions with another party or transactions which would increase the equity ownership of a shareholder who then owned 15% or more of Devon, each Devon right will entitle its holder to purchase securities of the merging or acquiring party with a value equal to twice the exercise price of the right.

The rights, which have no voting power, expire on August 17, 2009. The rights may be redeemed by Devon for $0.01 per right until the rights become exercisable.

Dividends

Dividends on Devon's common stock were paid in 2005, 2004 and 2003 at a per share rate of $0.075, $0.05 and $0.025 per quarter, respectively.

10. FINANCIAL INSTRUMENTS

The following table presents the carrying amounts and estimated fair values of Devon's financial instrument assets (liabilities) at December 31, 2005 and 2004.

	2005		2004	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
	(IN MILLIONS)			
Investment in Chevron Corporation common stock	$ 805	805	745	745
Oil and gas price hedge agreements	$ —	—	(395)	(395)
Interest rate swap agreements	$ (22)	(22)	—	—
Embedded option in exchangeable debentures	$ (121)	(121)	(67)	(67)
Long-term debt	$ (6,619)	(7,642)	(7,964)	(9,046)

The following methods and assumptions were used to estimate the fair values of the financial instruments in the above table. The carrying values of cash and cash equivalents, short-term investments, accounts receivable and accounts payable (including income taxes payable and accrued expenses) included in the accompanying consolidated balance sheets approximated fair value at December 31, 2005 and 2004.

Investment in Chevron Corporation common stock — The fair value of this investment is based on a quoted market price.

Oil and Gas Price Hedge Agreements — The fair values of the oil and gas price hedges were based on either (a) an internal discounted cash flow calculation, (b) quotes obtained from the counterparty to the hedge agreement or (c) quotes provided by brokers.

Interest Rate Swap Agreements — The fair values of the interest rate swaps are based on internal discounted cash flow calculations, using market quotes of future interest rates, or quotes obtained from counterparties.

Embedded Option in Exchangeable Debentures — The fair value of the embedded option is based on a quote obtained from a broker.

Long-term Debt — The fair values of the fixed-rate long-term debt are based on quotes obtained from brokers or by discounting the principal and interest payments at rates available for debt of similar terms and maturity. The fair values of the floating-rate long-term debt are estimated to approximate the carrying amounts due to the fact that the interest rates paid on such debt are generally set for periods of three months or less.

Interest Rate Swaps

Devon has also entered into fixed-to-floating interest rate swaps. Following is a table summarizing the fixed-to-floating interest rate swaps with the related debt instrument and notional amounts.

DEBT INSTRUMENT	NOTIONAL AMOUNT (IN MILLIONS)	FLOATING RATE
2.75% notes due in 2006	$ 500	LIBOR less 26.8 basis points
6.55% senior notes due 2006	$ 172 (1)	Banker's Acceptance plus 340 basis points
4.375% senior notes due in 2007	$ 400	LIBOR plus 40 basis points

(1) Converted from $200 million Canadian dollars at a Canadian-to-U.S. dollar exchange rate of $0.8577 at December 31, 2005.

11. RETIREMENT PLANS

Devon has various non-contributory defined benefit pension plans, including qualified plans ("Qualified Plans") and nonqualified plans ("Supplemental Plans"). The Qualified Plans provide retirement benefits for U.S. and Canadian employees meeting certain age and service requirements. Benefits for the Qualified Plans are based on the employee's years of service and compensation and are funded from assets held in the plans' trusts.

Devon has a funding policy regarding the Qualified Plans such that it will contribute the amount of funds necessary so that the Qualified Plans' assets will be approximately equal to the related accumulated benefit obligation. As of December 31, 2005 and 2004, the fair value of the Qualified Plans' assets were $533 million and $456 million, respectively, which was $37 million and $11 million more, respectively, than the related accumulated benefit obligation. The actual amount of contributions required during future periods will depend on investment returns from the plan assets during the same period as well as changes in long-term interest rates.

The Supplemental Plans provide retirement benefits for certain employees whose benefits under the Qualified Plans are limited by income tax regulations. The Supplemental Plans' benefits are based on the employee's years of service and compensation. For certain Supplemental Plans, Devon has established trusts to fund these plans' benefit obligations. The total values of these trusts were $59 million and $60 million at December 31, 2005 and 2004, respectively, and are included in non-current other assets in the consolidated balance sheets. For the remaining Supplemental Plans for which trusts have not been established, benefits are funded from Devon's available cash and cash equivalents.

Devon also has defined benefit postretirement plans ("Postretirement Plans") which provide benefits for substantially all employees. The Postretirement Plans provide medical and, in some cases, life insurance benefits and are, depending on the type of plan, either contributory or non-contributory. Benefit obligations for the Postretirement Plans are estimated based on future cost-sharing changes that are consistent with Devon's expressed intent to increase, where possible, contributions from future retirees. Devon's funding policy for the Postretirement Plans is to fund the benefits as they become payable with available cash and cash equivalents.

Benefit Obligations

In 2005, Devon accelerated the date for actuarial measurement of its pension and postretirement benefit plans' obligations from December 31 to November 30. Devon believes the one-month acceleration of the measurement date is a preferred change as it allows adequate time for Devon management to evaluate and report the actuarial pension and postretirement measurements, while facilitating the timely preparation of year-end financial statements. The effect of the change on the obligation and assets of the pension and postretirement benefit plans did not have a material cumulative effect on the net periodic benefit cost or benefit obligation. Accordingly, all amounts reported in the tables below for the year ended December 31, 2005, are based on a measurement date of November 30, 2005, and amounts reported for the year ended December 31, 2004, are based upon a measurement date of December 31, 2004.

The following table presents the plans' benefit obligations and the weighted-average actuarial assumptions used to calculate such obligations at December 31, 2005 and 2004. The benefit obligation for pension plans represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated benefit obligation. The accumulated benefit obligation differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated benefit obligation for pension plans at December 31, 2005 and 2004 was $607 million and $542 million, respectively.

	PENSION BENEFITS		OTHER POSTRETIREMENT BENEFITS	
	2005	2004	2005	2004
	(IN MILLIONS)			
CHANGE IN BENEFIT OBLIGATION:				
Benefit obligation at beginning of year	$ 588	512	50	70
Service cost	18	15	1	1
Interest cost	34	32	3	3
Participant contributions	—	—	2	1
Amendments	1	1	—	(7)
Special termination benefits	—	1	—	—
Foreign exchange rate changes	1	2	—	—
Actuarial loss (gain)	50	52	6	(10)
Benefits paid	(26)	(27)	(8)	(8)
Benefit obligation at end of year	$ 666	588	54	50
ACTUARIAL ASSUMPTIONS:				
Discount rate	5.72%	5.74%	5.75%	5.75%
Rate of compensation increase	4.50%	4.50%	N/A	N/A

Future pension and postretirement obligations are discounted at the end of each year based on the rate at which obligations could be effectively settled, considering the timing of estimated benefit payments. This rate is based on high-quality bond yields, after allowing for call and default risk. High quality corporate bond yield indices, such as Moody's Aa, are considered when selecting the discount rate.

For measurement purposes, a 10% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2006. The rate was assumed to decrease one percent annually to 5% in the year 2011 and remain at that level thereafter. A one-percentage-point increase in assumed health care cost trend rates would increase the December 31, 2005 postretirement benefit obligation by $2 million, while a one-percentage-point decrease in the same rate would decrease the postretirement benefit obligation by $1 million.

Plan Assets

The following table presents the plans' assets at December 31, 2005 and 2004.

	PENSION BENEFITS		OTHER POSTRETIREMENT BENEFITS	
	2005	2004	2005	2004
	(IN MILLIONS)			
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at beginning of year	$ 456	375	—	—
Actual return on plan assets	37	40	—	—
Employer contributions	65	70	6	7
Participant contributions	—	—	2	1
Transfer to defined contribution plan	—	(3)	—	—
Benefits paid	(26)	(27)	(8)	(8)
Foreign exchange rate changes	1	1	—	—
Fair value of plan assets at end of year	$ 533	456	—	—

The plan assets for pension benefits in the table above excludes the assets held in trusts for the Supplemental Plans. However, employer contributions for pension benefits in the table above include $5 million in 2005 and $6 million in 2004 which were transferred from the trusts established for the Supplemental Plans.

Devon's overall investment objective for its retirement plans' assets is to achieve long-term growth of invested capital to ensure payments of retirement benefits obligations can be funded when required. To assist in achieving this objective, Devon has established certain investment strategies, including target allocation percentages and permitted and prohibited investments, designed to mitigate risks inherent with investing. At December 31, 2005, the target investment allocation for Devon's plan assets is 50% U.S. large cap equity securities; 15% U.S. small cap equity securities, equally allocated between growth and value; 15% international equity securities, equally allocated between growth and value; and 20% debt securities. Derivatives or other speculative investments considered high-risk are generally prohibited.

The asset allocation for Devon's retirement plans at December 31, 2005 and 2004, and the target allocation for 2006, by asset category, follows:

	TARGET ALLOCATION	PERCENTAGE OF PLAN ASSETS AT YEAR END	
	2006	2005	2004
Equity securities	80%	83%	82%
Debt securities	20%	16%	17%
Other	—	1%	1%
Total	100%	100%	100%

Funded Status

The following table presents the funded status of the plans and the net amounts recognized in the consolidated balance sheets at December 31, 2005 and 2004.

	PENSION BENEFITS		OTHER POSTRETIREMENT BENEFITS	
	2005	2004	2005	2004
	(IN MILLIONS)			
NET AMOUNTS RECOGNIZED IN CONSOLIDATED BALANCE SHEETS:				
Fair value of plan assets	$ 533	456	—	—
Benefit obligations	666	588	54	50
Funded status	(133)	(132)	(54)	(50)
Unrecognized net actuarial loss	195	155	7	1
Unrecognized prior service cost (benefit)	6	5	(8)	(9)
Net amounts recognized	$ 68	28	(55)	(58)
COMPONENTS OF NET AMOUNTS RECOGNIZED IN THE CONSOLIDATED BALANCE SHEETS:				
Prepaid cost	$ 144	98	—	—
Accrued benefit cost	(109)	(96)	(55)	(58)
Intangible asset	3	4	—	—
Accumulated other comprehensive income	30	22	—	—
Net amount recognized	$ 68	28	(55)	(58)

During 2005, the pre-tax change in the minimum pension liability increased (decreased) other comprehensive income by $(8) million, $61 million and $28 million, respectively.

Certain of Devon's pension and postretirement plans have a projected benefit obligation in excess of plan assets at December 31, 2005 and 2004. The aggregate benefit obligation and fair value of plan assets for these plans is included below.

	DECEMBER 31, 2005	2004
	(IN MILLIONS)	
Projected benefit obligation	$ 707	626
Fair value of plan assets	$ 518	441

Certain of Devon's pension plans have an accumulated benefit obligation in excess of plan assets at December 31, 2005 and 2004. The aggregate accumulated benefit obligation and fair value of plan assets for these plans is included below.

	DECEMBER 31, 2005	2004
	(IN MILLIONS)	
Accumulated benefit obligation	$ 111	98
Fair value of plan assets	$ —	—

The plan assets included in the tables above exclude the Supplemental Plan trusts which had a total value of $59 million and $60 million at December 31, 2005 and 2004, respectively.

Net Periodic Cost

The following table presents the plans' net periodic benefit cost and the weighted-average actuarial assumptions used to calculate such cost for the years ended December 31, 2005, 2004 and 2003.

	PENSION BENEFITS 2005	2004	2003	OTHER POSTRETIREMENT BENEFITS 2005	2004	2003
	(IN MILLIONS)					
COMPONENTS OF NET PERIODIC BENEFIT COST:						
Service cost	$ 18	15	12	1	1	1
Interest cost	35	32	31	3	4	4
Expected return on plan assets	(36)	(30)	(22)	—	—	—
Curtailment loss	—	—	1	—	—	—
Termination benefits	—	1	—	—	—	—
Amortization of prior service cost	1	1	1	(1)	(1)	—
Recognized net actuarial loss	8	7	12	—	—	—
Net periodic benefit cost	$ 26	26	35	3	4	5
ACTUARIAL ASSUMPTIONS:						
Discount rate	5.98%	6.23%	6.53%	6.00%	6.25%	6.75%
Expected return on plan assets	8.40%	8.34%	8.25%	N/A	N/A	N/A
Rate of compensation increase	4.50%	4.88%	4.88%	N/A	N/A	N/A

The expected rate of return on plan assets was determined by evaluating input from external consultants and economists as well as long-term inflation assumptions. Devon expects the long-term asset allocation to approximate the targeted allocation. Therefore, the expected long-term rate of return on plan assets is based on the target allocation of investment types in such assets.

Assumed health care cost trend rates have a significant effect on the amounts reported for the other postretirement benefit plans. A one-percentage-point change in the assumed health care cost trend rates would affect the total service and interest cost by less than $1 million.

In December 2003, the *Medicare Prescription Drug, Improvement and Modernization Act of 2003* ("the Act") was signed into law. The Act introduces a prescription drug benefit under Medicare ("Medicare Part D") as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. In May 2004 the Financial Accounting Standards Board ("FASB") issued FASB Staff Position No. 106-2, *"Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"* ("FSP 106-2"). If the benefit provided is at least actuarially equivalent to Medicare Part D, FSP 106-2 requires companies to account for the effect of the subsidy on benefits attributable to past service as an actuarial experience gain that reduces the accumulated postretirement benefit obligation and for benefits attributable to current service as a reduction of the service cost included in net periodic benefit cost. FSP 106-2 is effective for the first interim period beginning after June 15, 2004. Because benefits provided to certain participants in the Postretirement Plans will be at least actuarially equivalent to Medicare Part D, Devon would be entitled to some subsidy. As a result, Devon reduced the accumulated postretirement benefit obligation at July 1, 2004, by $4 million and the net periodic postretirement benefit cost by $0.2 million for the year ended December 31, 2004. However, Devon made a decision during 2005 to not apply for the subsidy. Therefore, the amounts reported for 2005 do not reflect the impact of any potential subsidy.

Expected Cash Flows

Information about the expected cash flows for the pension and other postretirement benefit plans follows:

	PENSION BENEFITS	OTHER POSTRETIREMENT BENEFITS
	(IN MILLIONS)	
Employer contributions — 2006	$ 7	5
Benefit payments:		
2006	$ 29	5
2007	$ 30	5
2008	$ 32	5
2009	$ 33	5
2010	$ 35	5
2011 - 2015	$ 213	23

Expected employer contributions included in the table above include amounts related to Devon's Qualified Plans, Supplemental Plans and Postretirement Plans. Of the benefits expected to be paid in 2006, $7 million is expected to be funded from the trusts established for the Supplemental Plans and $5 million is expected to be funded from Devon's available cash and cash equivalents. Expected employer contributions and benefit payments for other postretirement benefits are presented net of employee contributions.

Other Benefit Plans

Devon has incurred certain postemployment benefits to former or inactive employees who are not retirees. These benefits include salary continuance, severance and disability health care and life insurance. The accrued postemployment benefit liability was approximately $5 million at December 31, 2005 and 2004.

Devon has a 401(k) Incentive Savings Plan which covers all domestic employees. At its discretion, Devon may match a certain percentage of the employees' contributions to the plan. The matching percentage is determined annually by the Board of Directors. Devon's matching contributions to the plan were $12 million, $11 million and $10 million for the years ended December 31, 2005, 2004 and 2003, respectively.

Devon has defined contribution pension plans for its Canadian employees. Devon makes a contribution to each employee which is based upon the employee's base compensation and classification. Such contributions are subject to maximum amounts allowed under the Income Tax Act (Canada). Devon also has a savings plan for its Canadian employees. Under the savings plan, Devon contributes a base percentage amount to all employees and the employee may elect to contribute an additional percentage amount (up to a maximum amount) which is matched by additional Devon contributions. During 2005, 2004 and 2003, Devon's combined contributions to the Canadian defined contribution plan and the Canadian savings plan were $10 million, $9 million and $8 million, respectively.

12. COMMITMENTS AND CONTINGENCIES

Devon is party to various legal actions arising in the normal course of business. Matters that are probable of unfavorable outcome to Devon and which can be reasonably estimated are accrued. Such accruals are based on information known about the matters, Devon's estimates of the outcomes of such matters and its experience in contesting, litigating and settling similar matters. None of the actions are believed by management to involve future amounts that would be material to Devon's financial position or results of operations after consideration of recorded accruals although actual amounts could differ materially from management's estimate.

Environmental Matters

Devon is subject to certain laws and regulations relating to environmental remediation activities associated with past operations, such as the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") and similar state statutes. In response to liabilities associated with these activities, accruals have been established when reasonable estimates are possible. Such accruals primarily include estimated costs associated with remediation. Devon has not used discounting in determining its accrued liabilities for environmental remediation, and no material claims for possible recovery from third party insurers or other parties related to environmental costs have been recognized in Devon's consolidated financial statements. Devon adjusts the accruals when new remediation responsibilities are discovered and probable costs become estimable, or when current remediation estimates must be adjusted to reflect new information.

Certain of Devon's subsidiaries acquired in past mergers are involved in matters in which it has been alleged that such subsidiaries are potentially responsible parties ("PRPs") under CERCLA or similar state legislation with respect to various waste disposal areas owned or operated by third parties. As of December 31, 2005, Devon's consolidated balance sheet included $4 million of non-current accrued liabilities, reflected in "Other liabilities," related to these and other environmental remediation liabilities. Devon does not currently believe there is a reasonable possibility of incurring additional material costs in excess of the current accruals recognized for such environmental remediation activities. With respect to the sites in which Devon subsidiaries are PRPs, Devon's conclusion is based in large part on (i) Devon's participation in consent decrees with both other PRPs and the Environmental Protection Agency, which provide for performing the scope of work required for remediation and contain covenants not to sue as protection to the PRPs, (ii) participation in groups as a *de minimis PRP*, and (iii) the availability of other defenses to liability. As a result, Devon's monetary exposure is not expected to be material.

Royalty Matters

Numerous gas producers and related parties, including Devon, have been named in various lawsuits alleging violation of the federal False Claims Act. The suits allege that the producers and related parties used below-market prices, improper deductions, improper measurement techniques and transactions with affiliates which resulted in underpayment of royalties in connection with natural gas and natural gas liquids produced and sold from federal and Indian owned or controlled lands. The principal suit in which Devon is a defendant is United States ex rel. Wright v. Chevron USA, Inc. et al. (the "Wright case"). The suit was originally filed in August 1996 in the United States District Court for the Eastern District of Texas, but was consolidated in October 2000 with the other suits for pre-trial proceedings in the United States District Court for the District of Wyoming. On July 10, 2003, the District of Wyoming remanded the Wright case back to the Eastern District of Texas to resume proceedings. Trial is set for February 2007 if the suit continues to advance. Devon believes that it has acted reasonably, has legitimate and strong defenses to all allegations in the suit, and has paid royalties in good faith. Devon does not currently believe that it is subject to material exposure in association with this lawsuit and no liability has been recorded in connection therewith.

Devon has been a defendant in certain private royalty owner litigation filed in Wyoming regarding deductibility of certain post production costs from royalties payable by Devon. A significant portion of such production is, or will be, transported through facilities owned by Thunder Creek Gas Services, L.L.C., of which Devon owns a 75% interest. During 2005, all of the litigation was resolved for amounts immaterial to Devon.

Equatorial Guinea Investigation

The SEC has been conducting an inquiry into payments made to the government of Equatorial Guinea, and to officials and persons affiliated with officials of the government of Equatorial Guinea. On August 9, 2005, Devon received a subpoena issued by the SEC pursuant to a formal order of investigation. Devon has cooperated fully with the SEC's previous requests for information in this inquiry and plans to continue to work with the SEC in connection with its formal investigation.

Hurricane Contingencies

Devon maintains a comprehensive insurance program that includes coverage for physical damage to its offshore facilities caused by hurricanes. Devon's insurance program also includes substantial business interruption coverage which Devon expects to utilize to recover costs associated with the suspended production related to hurricanes that struck the Gulf of Mexico in the third quarter of 2005. Under the terms of the insurance program, Devon is entitled to be reimbursed for the portion of production suspended longer than forty-five days, subject to upper limits to oil and natural gas prices. Also, the terms of the insurance include a standard, per-event deductible of $1 million for offshore losses as well as a $15 million aggregate annual deductible. Based on current estimates of physical damage and the anticipated length of time Devon will have production suspended, Devon expects its policy settlements will exceed repair costs and deductible amounts. This expectation is based upon several variables, including the actual amount of time that production is suspended, the actual prices in effect while production is suspended and the timing of collections of insurance proceeds. Should Devon's policy settlements exceed repair costs and deductible amounts, the excess will be recognized as other income in the statement of operations.

Other Matters

Devon is involved in other various routine legal proceedings incidental to its business. However, to Devon's knowledge as of the date of this report, there were no other material pending legal proceedings to which Devon is a party or to which any of its property is subject.

Commitments

Devon has certain drilling and facility obligations under contractual agreements with third party service providers to procure drilling rigs and other drilling related services for developmental and exploratory drilling.

Devon has certain firm transportation agreements which represent "ship or pay" arrangements whereby Devon has committed to ship certain volumes of oil, gas and NGLs for a fixed transportation fee. Devon has entered into these agreements to aid the movement of its gas production to market. Devon expects to have sufficient production to utilize the majority of these transportation services.

Devon leases certain office space and equipment under operating lease arrangements. Total rental expense included in general and administrative expenses under operating leases, net of sub-lease income, was $35 million, $49 million and $51 million in 2005, 2004 and 2003, respectively.

Devon assumed two offshore platform spar leases through the 2003 Ocean merger. The spars are being used in the development of the Nansen and Boomvang fields in the Gulf of Mexico. The Boomvang field was divested as part of the 2005 property divestiture program. Therefore, Devon no longer has any obligation under the related Boomvang spar lease. The Nansen operating lease is for a 20-year term and contains various options whereby Devon may purchase the lessors' interests in the spar. Total rental expense included in lease operating expenses under both the Nansen and Boomvang operating leases was $14 million, $17 million and $11 million in 2005, 2004 and 2003, respectively. Devon has guaranteed that the Nansen spar will have a residual value at the end of the operating leases equal to at least 10% of the fair value of the spar at the inception of the lease. The total guaranteed value is $14 million in 2022. However, such amount may be reduced under the terms of the lease agreement. As a result of the sale of the Boomvang field, Devon is subleasing the Boomvang Spar. If the sublessee defaults on its obligation, Devon would be required to continue making the lease payments and any guaranteed payment required at the end of the term.

Devon has a floating, production, storage and offloading facility ("FPSO") that is being used in the Panyu project offshore China and is being leased under operating lease arrangements. This lease expires in September 2009. Devon was also leasing an FPSO that is being used in the Zafiro field offshore Equatorial Guinea. Devon and the other working interest owners purchased this FPSO in the fourth quarter of 2005. Total rental expense included in lease operating expenses under both the China and Equatorial Guinea operating leases was $19 million, $20 million and $6 million in 2005, 2004 and 2003, respectively.

The following is a schedule by year of future minimum payments for drilling and facility obligations, firm transportation agreements and leases that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 2005:

YEAR ENDING DECEMBER 31,	DRILLING AND FACILITY OBLIGATIONS	FIRM TRANSPORTATION AGREEMENTS	OFFICE AND EQUIPMENT LEASES	SPAR LEASES	FPSO LEASES
			(IN MILLIONS)		
2006	$ 666	102	35	11	7
2007	261	89	33	11	7
2008	180	66	28	11	7
2009	118	52	25	11	6
2010	93	38	23	11	—
Thereafter	—	131	53	150	—
Total payments	$ 1,318	478	197	205	27

13. REDUCTION OF CARRYING VALUE OF OIL AND GAS PROPERTIES

Under the full cost method of accounting, the net book value of oil and gas properties, less related deferred income taxes, may not exceed a calculated "ceiling." The ceiling limitation is the discounted estimated after-tax future net revenues from proved oil and gas properties, excluding future cash outflows associated with settling asset retirement obligations included in the net book value of oil and gas properties, plus the cost of properties not subject to amortization. The ceiling is determined separately by country. In calculating future net revenues, prices and costs used are those as of the end of the appropriate quarterly period. These prices are not changed except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including cash flow hedges in place. We had no such hedges outstanding at December 31, 2005.

The net book value, less related deferred tax liabilities, is compared to the ceiling on a quarterly and annual basis. Any excess of the net book value, less related deferred taxes, is written off as an expense. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

Under the purchase method of accounting for business combinations, acquired oil and gas properties are recorded at estimated fair value as of the date of purchase. Devon estimates such fair value using its estimates of future oil, gas and NGL prices. In contrast, the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely. Accordingly, the resulting value from the ceiling calculation is not necessarily indicative of the fair value of the reserves.

During 2005 and 2003, Devon reduced the carrying value of its oil and gas properties due to full cost ceiling limitations, as well as due to unsuccessful exploratory activities. A summary of these reductions and additional discussion is provided below.

		YEAR ENDED DECEMBER 31,			
		2005		2003	
		GROSS	NET OF TAXES	GROSS	NET OF TAXES
		(IN MILLIONS)			
CEILING TEST REDUCTIONS:					
Egypt	$	—	—	45	26
Indonesia		—	—	4	1
Russia		—	—	19	9
UNSUCCESSFUL EXPLORATORY REDUCTIONS:					
Angola		170	119	—	—
Brazil		42	42	11	7
Ghana		—	—	26	26
Other		—	—	6	5
Total	$	212	161	111	74

2005 Reductions

Devon's interests in Angola were acquired through the Ocean Energy acquisition. Devon's drilling program has been unsuccessful in Angola, resulting in no proven reserves for the country. After drilling a series of unsuccessful wells in the fourth quarter of 2005, Devon determined that all of the Angolan capitalized costs should be impaired. Devon has a commitment to drill one well in Angola by the end of August 2006.

Prior to the fourth quarter of 2005, we were capitalizing the costs of previous unsuccessful efforts in Brazil pending the determination of whether proved reserves would be recorded in Brazil. We have been successful in our drilling efforts on block BM-C-8 in Brazil, and are currently developing our Polvo project on this block. The ultimate value of the Polvo project is expected to be in excess of the sum of its related costs, plus the costs of the previous unrelated unsuccessful efforts in Brazil which were capitalized. However, the Polvo proved reserves will be recorded over a period of time. It is expected that a small initial portion of the proved reserves ultimately expected at Polvo will be recorded in 2006. Based on preliminary estimates developed in the fourth quarter of 2005, the value of this initial partial booking of proved reserves will not be sufficient to offset the sum of the related proportionate Polvo costs plus the costs of the previous unrelated unsuccessful efforts. Therefore, we determined that the prior unsuccessful costs unrelated to the Polvo project should be impaired. These costs totaled approximately $42 million. There is no tax benefit related to the Brazilian impairment.

2003 Reductions

The Egyptian reduction was primarily due to poor results of a development well that was unsuccessful in the primary objective. Partially as a result of this well, Devon revised Egyptian proved reserves downward. The Russian reduction was primarily the result of additional capital costs incurred as well as an increase in operating costs. The Indonesian reduction was primarily related to an increase in operating costs and a reduction in proved reserves.

Additionally, during 2003, Devon elected to discontinue certain exploratory activities in Ghana, certain properties in Brazil and other smaller concessions. After meeting the drilling and capital commitments on these properties, Devon determined that these properties did not meet its internal criteria to justify further investment. Accordingly, Devon recorded a charge associated with the impairment of these properties.

14. SEGMENT INFORMATION

Devon manages its business by country. As such, Devon identifies its segments based on geographic areas. Devon has three reportable segments: its operations in the U.S., its operations in Canada, and its international operations outside of North America. Substantially all of these segments' operations involve oil and gas producing activities. Certain information regarding such activities for each segment is included in Note 15.

Following is certain financial information regarding Devon's segments for 2005, 2004 and 2003. The revenues reported are all from external customers.

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
AS OF DECEMBER 31, 2005:				
Current assets	$ 2,042	1,182	982	4,206
Property and equipment, net of accumulated depreciation, depletion and amortization	10,856	5,877	2,399	19,132
Goodwill	3,056	2,581	68	5,705
Other assets	1,213	17	—	1,230
Total assets	$ 17,167	9,657	3,449	30,273
Current liabilities	$ 1,736	925	273	2,934
Long-term debt	2,986	2,971	—	5,957
Asset retirement obligation, long-term	320	261	37	618
Other liabilities	467	12	18	497
Deferred income taxes	2,994	2,008	403	5,405
Stockholders' equity	8,664	3,480	2,718	14,862
Total liabilities and stockholders' equity	$ 17,167	9,657	3,449	30,273
YEAR ENDED DECEMBER 31, 2005:				
Revenues:				
Oil sales	$ 1,062	353	1,063	2,478
Gas sales	3,929	1,814	41	5,784
NGL sales	484	196	7	687
Marketing and midstream revenues	1,780	12	—	1,792
Total revenues	7,255	2,375	1,111	10,741
Expenses and other income, net:				
Lease operating expenses	710	498	137	1,345
Production taxes	273	6	56	335
Marketing and midstream operating costs and expenses	1,336	6	—	1,342
Depreciation, depletion and amortization of oil and gas properties	1,137	570	324	2,031
Depreciation and amortization of non-oil and gas properties	141	14	5	160
Accretion of asset retirement obligation	25	16	3	44
General and administrative expenses	245	59	(13)	291
Interest expense	224	309	—	533
Effects of changes in foreign currency exchange rates	—	(1)	(1)	(2)
Change in fair value of derivative financial instruments	86	8	—	94
Reduction of carrying value of oil and gas properties	—	—	212	212
Other income, net	(176)	(9)	(11)	(196)
Total expenses and other income, net	4,001	1,476	712	6,189
Earnings before income tax expense	3,254	899	399	4,552
Income tax expense (benefit):				
Current	890	106	242	1,238
Deferred	195	217	(28)	384
Total income tax expense	1,085	323	214	1,622
Net earnings	2,169	576	185	2,930
Preferred stock dividends	10	—	—	10
Net earnings applicable to common stockholders	$ 2,159	576	185	2,920
Capital expenditures	$ 2,095	1,657	338	4,090

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
AS OF DECEMBER 31, 2004:				
Current assets	$ 2,196	1,109	567	3,872
Property and equipment, net of accumulated depreciation, depletion and amortization	11,011	5,741	2,594	19,346
Goodwill	3,061	2,508	68	5,637
Other assets	1,123	19	28	1,170
Total assets	$ 17,391	9,377	3,257	30,025
Current liabilities	$ 1,933	800	367	3,100
Long-term debt	3,496	3,535	—	7,031
Asset retirement obligation, long-term	412	250	31	693
Other liabilities	400	21	17	438
Deferred income taxes	2,853	1,805	431	5,089
Stockholders' equity	8,297	2,966	2,411	13,674
Total liabilities and stockholders' equity	$ 17,391	9,377	3,257	30,025
YEAR ENDED DECEMBER 31, 2004:				
Revenues:				
Oil sales	$ 976	299	927	2,202
Gas sales	3,261	1,437	34	4,732
NGL sales	405	143	6	554
Marketing and midstream revenues	1,688	13	—	1,701
Total revenues	6,330	1,892	967	9,189
Expenses and other income, net:				
Lease operating expenses	714	438	128	1,280
Production taxes	220	5	30	255
Marketing and midstream operating costs and expenses	1,333	6	—	1,339
Depreciation, depletion and amortization of oil and gas properties	1,242	522	377	2,141
Depreciation and amortization of non-oil and gas properties	130	14	5	149
Accretion of asset retirement obligation	27	15	2	44
General and administrative expenses	221	56	—	277
Interest expense	197	278	—	475
Effects of changes in foreign currency exchange rates	—	(22)	(1)	(23)
Change in fair value of derivative financial instruments	63	(1)	—	62
Other income, net	(81)	(17)	(5)	(103)
Total expenses and other income, net	4,066	1,294	536	5,896
Earnings before income tax expense	2,264	598	431	3,293
Income tax expense (benefit):				
Current	483	49	220	752
Deferred	240	149	(34)	355
Total income tax expense	723	198	186	1,107
Net earnings	1,541	400	245	2,186
Preferred stock dividends	10	—	—	10
Net earnings applicable to common stockholders	$ 1,531	400	245	2,176
Capital expenditures	$ 1,785	975	343	3,103

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
YEAR ENDED DECEMBER 31, 2003:				
Revenues:				
Oil sales	$ 861	318	409	1,588
Gas sales	2,652	1,222	23	3,897
NGL sales	289	114	4	407
Marketing and midstream revenues	1,443	17	—	1,460
Total revenues	5,245	1,671	436	7,352
Expenses and other income, net:				
Lease operating expenses	617	392	69	1,078
Production taxes	194	3	7	204
Marketing and midstream operating costs and expenses	1,165	9	—	1,174
Depreciation, depletion and amortization of oil and gas properties	1,084	389	195	1,668
Depreciation and amortization of non-oil and gas properties	111	10	4	125
Accretion of asset retirement obligation	22	13	1	36
General and administrative expenses	252	43	12	307
Expenses related to mergers	7	—	—	7
Reduction in carrying value of oil and gas properties	—	—	111	111
Interest expense	211	285	6	502
Effects of changes in foreign currency exchange rates	—	(69)	—	(69)
Change in fair value of derivative financial instruments	(2)	1	—	(1)
Other income, net	(19)	(8)	(8)	(35)
Total expenses and other income, net	3,642	1,068	397	5,107
Earnings before income tax expense (benefit) and cumulative effect of change in accounting principle	1,603	603	39	2,245
Income tax expense (benefit):				
Current	131	(9)	71	193
Deferred	377	(16)	(40)	321
Total income tax expense (benefit)	508	(25)	31	514
Earnings before cumulative effect of change in accounting principle	1,095	628	8	1,731
Cumulative effect of change in accounting principle	11	5	—	16
Net earnings	1,106	633	8	1,747
Preferred stock dividends	10	—	—	10
Net earnings applicable to common stockholders	$ 1,096	633	8	1,737
Capital expenditures	$ 1,579	704	304	2,587

15. SUPPLEMENTAL INFORMATION ON OIL AND GAS OPERATIONS (UNAUDITED)

The following supplemental unaudited information regarding the oil and gas activities of Devon is presented pursuant to the disclosure requirements promulgated by the Securities and Exchange Commission and SFAS No. 69, *Disclosures About Oil and Gas Producing Activities.*

Costs Incurred

The following tables reflect the costs incurred in oil and gas property acquisition, exploration, and development activities:

	TOTAL YEAR ENDED DECEMBER 31,		
	2005	2004	2003
		(IN MILLIONS)	
Property acquisition costs:			
Proved properties	$ 54	38	4,343
Unproved properties — business combinations	—	—	1,063
Unproved properties — other acquisitions	349	141	87
Total unproved properties	349	141	1,150
Exploration costs	931	735	714
Development costs	2,805	1,938	1,864
Costs incurred	$ 4,139	2,852	8,071

	DOMESTIC		
	YEAR ENDED DECEMBER 31,		
	2005	2004	2003
	(IN MILLIONS)		
Property acquisition costs:			
Proved properties	$ 5	27	2,697
Unproved properties — business combinations	—	—	551
Unproved properties — other acquisitions	106	75	48
Total unproved properties	106	75	599
Exploration costs	422	335	343
Development costs	1,597	1,163	1,193
Costs incurred	$ 2,130	1,600	4,832

	CANADA		
	YEAR ENDED DECEMBER 31,		
	2005	2004	2003
	(IN MILLIONS)		
Property acquisition costs:			
Proved properties	$ 49	11	26
Unproved properties — business combinations	—	—	—
Unproved properties — other acquisitions	239	52	39
Total unproved properties	239	52	39
Exploration costs	361	272	214
Development costs	1,020	625	491
Costs incurred	$ 1,669	960	770

	INTERNATIONAL		
	YEAR ENDED DECEMBER 31,		
	2005	2004	2003
	(IN MILLIONS)		
Property acquisition costs:			
Proved properties	$ —	—	1,620
Unproved properties — business combinations	—	—	512
Unproved properties — other acquisitions	4	14	—
Total unproved properties	4	14	512
Exploration costs	148	128	157
Development costs	188	150	180
Costs incurred	$ 340	292	2,469

Pursuant to the full cost method of accounting, Devon capitalizes certain of its general and administrative expenses which are related to property acquisition, exploration and development activities. Such capitalized expenses, which are included in the costs shown in the preceding tables, were $189 million, $172 million and $140 million in the years 2005, 2004 and 2003, respectively. Also, Devon capitalizes interest costs incurred and attributable to unproved oil and gas properties and major development projects of oil and gas properties. Capitalized interest expenses, which are included in the costs shown in the preceding tables, were $70 million, $70 million and $50 million in the years 2005, 2004 and 2003, respectively.

Results of Operations for Oil and Gas Producing Activities

The following tables include revenues and expenses associated directly with Devon's oil and gas producing activities, including general and administrative expenses directly related to such producing activities. They do not include any allocation of Devon's interest costs or general corporate overhead and, therefore, are not necessarily indicative of the contribution to net earnings of Devon's oil and gas operations. Income tax expense has been calculated by applying statutory income tax rates to oil, gas and NGL sales after deducting costs, including depreciation, depletion and amortization and after giving effect to permanent differences.

	TOTAL			
	YEAR ENDED DECEMBER 31,			
		2005	2004	2003
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)			
Oil, gas and NGL sales	$	8,949	7,488	5,892
Production and operating expenses		(1,680)	(1,535)	(1,282)
Depreciation, depletion and amortization		(2,031)	(2,141)	(1,668)
Accretion of asset retirement obligation		(44)	(44)	(36)
General and administrative expenses directly related to oil and gas producing activities		(43)	(38)	(48)
Reduction of carrying value of oil and gas properties		(212)	—	(111)
Income tax expense		(1,806)	(1,288)	(895)
Results of operations for oil and gas producing activities	$	3,133	2,442	1,852
Depreciation, depletion and amortization per equivalent barrel of production	$	8.99	8.54	7.33

	DOMESTIC			
	YEAR ENDED DECEMBER 31,			
		2005	2004	2003
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)			
Oil, gas and NGL sales	$	5,475	4,642	3,802
Production and operating expenses		(983)	(934)	(811)
Depreciation, depletion and amortization		(1,137)	(1,242)	(1,084)
Accretion of asset retirement obligation		(25)	(27)	(22)
General and administrative expenses directly related to oil and gas producing activities		(23)	(22)	(27)
Income tax expense		(1,166)	(827)	(775)
Results of operations for oil and gas producing activities	$	2,141	1,590	1,083
Depreciation, depletion and amortization per equivalent barrel of production	$	8.35	8.23	7.42

	CANADA			
	YEAR ENDED DECEMBER 31,			
		2005	2004	2003
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)			
Oil, gas and NGL sales	$	2,363	1,879	1,654
Production and operating expenses		(504)	(443)	(395)
Depreciation, depletion and amortization		(570)	(522)	(388)
Accretion of asset retirement obligation		(16)	(15)	(13)
General and administrative expenses directly related to oil and gas producing activities		(20)	(16)	(15)
Income tax expense		(426)	(275)	(89)
Results of operations for oil and gas producing activities	$	827	608	754
Depreciation, depletion and amortization per equivalent barrel of production	$	9.20	8.00	6.17

	INTERNATIONAL			
	YEAR ENDED DECEMBER 31,			
		2005	2004	2003
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)			
Oil, gas and NGL sales	$	1,111	967	436
Production and operating expenses		(193)	(158)	(76)
Depreciation, depletion and amortization		(324)	(377)	(196)
Accretion of asset retirement obligation		(3)	(2)	(1)
General and administrative expenses directly related to oil and gas producing activities		—	—	(6)
Reduction of carrying value of oil and gas properties		(212)	—	(111)
Income tax expense		(214)	(186)	(31)
Results of operations for oil and gas producing activities	$	165	244	15
Depreciation, depletion and amortization per equivalent barrel of production	$	11.61	10.88	10.52

Quantities of Oil and Gas Reserves

Set forth below is a summary of the reserves which were evaluated, either by preparation or audit, by independent petroleum consultants for each of the years ended 2005, 2004 and 2003.

	2005		2004		2003	
	PREPARED	AUDITED	PREPARED	AUDITED	PREPARED	AUDITED
Domestic	9%	79%	16%	61%	33%	37%
Canada	46%	26%	22%	—	28%	—
International	98%	—	98%	—	98%	—
Total	31%	54%	28%	35%	42%	21%

"Prepared" reserves are those estimates of quantities of reserves which were prepared by an independent petroleum consultant. "Audited" reserves are those quantities of revenues which were estimated by Devon employees and audited by an independent petroleum consultant. An audit is an examination of a company's proved oil and gas reserves and net cash flow by an independent petroleum consultant that is conducted for the purpose of expressing an opinion as to whether such estimates, in aggregate, are reasonable and have been estimated and presented in conformity with generally accepted petroleum engineering and evaluation principles.

The domestic reserves were evaluated by the independent petroleum consultants of LaRoche Petroleum Consultants, Ltd. and Ryder Scott Company, L.P. in each of the years presented. The Canadian reserves were evaluated by the independent petroleum consultants of AJM Petroleum Consultants in each of the years presented. The International reserves were evaluated by the independent petroleum consultants of Ryder Scott Company, L.P. in each of the years presented.

Set forth below is a summary of the changes in the net quantities of crude oil, natural gas and natural gas liquids reserves for each of the three years ended December 31, 2005.

	TOTAL			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2002	444	5,836	192	1,609
Revisions due to prices	(4)	64	2	8
Revisions other than price	(5)	(73)	(2)	(19)
Extensions and discoveries	29	834	20	188
Purchase of reserves	262	1,650	19	556
Production	(62)	(863)	(22)	(228)
Sale of reserves	(3)	(132)	—	(25)
Proved reserves as of December 31, 2003	661	7,316	209	2,089
Revisions due to prices	(84)	39	1	(76)
Revisions other than price	19	30	21	45
Extensions and discoveries	78	988	25	268
Purchase of reserves	1	14	—	3
Production	(78)	(891)	(24)	(251)
Sale of reserves	(1)	(2)	—	(1)
Proved reserves as of December 31, 2004	596	7,494	232	2,077
Revisions due to prices	(16)	78	4	1
Revisions other than price	22	(3)	16	38
Extensions and discoveries	167	1,220	30	401
Purchase of reserves	2	10	—	4
Production	(64)	(827)	(24)	(226)
Sale of reserves	(58)	(676)	(12)	(183)
Proved reserves as of December 31, 2005	649	7,296	246	2,112
Proved developed reserves as of:				
December 31, 2002	260	4,618	150	1,180
December 31, 2003	408	5,980	179	1,584
December 31, 2004	411	6,219	204	1,652
December 31, 2005	363	6,111	216	1,599

	DOMESTIC			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2002	147	3,552	146	885
Revisions due to prices	3	93	3	21
Revisions other than price	(9)	(36)	(4)	(19)
Extensions and discoveries	12	510	14	111
Purchase of reserves	92	1,474	19	357
Production	(31)	(589)	(17)	(146)
Sale of reserves	(2)	(120)	—	(22)
Proved reserves as of December 31, 2003	212	4,884	161	1,187
Revisions due to prices	5	8	1	8
Revisions other than price	2	62	23	35
Extensions and discoveries	16	578	16	129
Purchase of reserves	—	8	—	1
Production	(31)	(602)	(19)	(151)
Sale of reserves	(1)	(2)	—	(1)
Proved reserves as of December 31, 2004	203	4,936	182	1,208
Revisions due to prices	6	58	3	19
Revisions other than price	2	238	19	61
Extensions and discoveries	16	793	20	169
Purchase of reserves	—	—	—	—
Production	(25)	(555)	(18)	(136)
Sale of reserves	(29)	(306)	(9)	(89)
Proved reserves as of December 31, 2005	173	5,164	197	1,232
Proved developed reserves as of:				
December 31, 2002	135	2,802	117	719
December 31, 2003	171	3,935	136	964
December 31, 2004	168	4,105	161	1,014
December 31, 2005	149	4,343	175	1,049

	CANADA			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2002	149	2,284	46	576
Revisions due to prices	1	(28)	(1)	(5)
Revisions other than price	(5)	(5)	2	(4)
Extensions and discoveries	16	324	6	76
Purchase of reserves	2	1	—	2
Production	(14)	(267)	(5)	(63)
Sale of reserves	(1)	(12)	—	(3)
Proved reserves as of December 31, 2003	148	2,297	48	579
Revisions due to prices	(43)	32	—	(38)
Revisions other than price	5	(46)	(2)	(5)
Extensions and discoveries	50	410	9	127
Purchase of reserves	1	6	—	2
Production	(14)	(279)	(5)	(65)
Sale of reserves	—	—	—	—
Proved reserves as of December 31, 2004	147	2,420	50	600
Revisions due to prices	—	22	1	4
Revisions other than price	2	(242)	(3)	(41)
Extensions and discoveries	144	427	10	225
Purchase of reserves	2	10	—	4
Production	(13)	(261)	(6)	(62)
Sale of reserves	(29)	(370)	(3)	(94)
Proved reserves as of December 31, 2005	253	2,006	49	636
Proved developed reserves as of:				
December 31, 2002	119	1,816	33	455
December 31, 2003	123	1,964	43	493
December 31, 2004	123	2,043	43	507
December 31, 2005	103	1,708	41	429

	INTERNATIONAL			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2002	148	—	—	148
Revisions due to prices	(8)	(1)	—	(8)
Revisions other than price	9	(32)	—	4
Extensions and discoveries	1	—	—	1
Purchase of reserves	168	175	—	197
Production	(17)	(7)	—	(19)
Sale of reserves	—	—	—	—
Proved reserves as of December 31, 2003	301	135	—	323
Revisions due to prices	(46)	(1)	—	(46)
Revisions other than price	12	14	—	15
Extensions and discoveries	12	—	—	12
Purchase of reserves	—	—	—	—
Production	(33)	(10)	—	(35)
Sale of reserves	—	—	—	—
Proved reserves as of December 31, 2004	246	138	—	269
Revisions due to prices	(22)	(2)	—	(22)
Revisions other than price	18	1	—	18
Extensions and discoveries	7	—	—	7
Purchase of reserves	—	—	—	—
Production	(26)	(11)	—	(28)
Sale of reserves	—	—	—	—
Proved reserves as of December 31, 2005	223	126	—	244
Proved developed reserves as of:				
December 31, 2002	6	—	—	6
December 31, 2003	114	81	—	127
December 31, 2004	120	71	—	131
December 31, 2005	111	60	—	121

The preceding International quantities of reserves are attributable to production sharing contracts with various foreign governments.

Standardized Measure of Discounted Future Net Cash Flows

The accompanying tables reflect the standardized measure of discounted future net cash flows relating to Devon's interest in proved reserves:

	TOTAL DECEMBER 31,		
	2005	2004	2003
	(IN MILLIONS)		
Future cash inflows	$ 94,648	67,035	60,562
Future costs:			
Development	(5,852)	(4,250)	(3,693)
Production	(23,840)	(18,395)	(16,232)
Future income tax expense	(22,007)	(14,241)	(12,078)
Future net cash flows	42,949	30,149	28,559
10% discount to reflect timing of cash flows	(19,375)	(14,064)	(12,638)
Standardized measure of discounted future net cash flows	$ 23,574	16,085	15,921

	DOMESTIC DECEMBER 31,		
	2005	2004	2003
	(IN MILLIONS)		
Future cash inflows	$ 55,954	39,214	36,602
Future costs:			
Development	(2,954)	(2,208)	(2,028)
Production	(14,882)	(12,093)	(10,788)
Future income tax expense	(13,061)	(7,989)	(6,848)
Future net cash flows	25,057	16,924	16,938
10% discount to reflect timing of cash flows	(11,781)	(7,550)	(7,435)
Standardized measure of discounted future net cash flows	$ 13,276	9,374	9,503

		CANADA		
		DECEMBER 31,		
		2005	2004	2003
		(IN MILLIONS)		
Future cash inflows	$	26,277	18,483	15,517
Future costs:				
Development		(1,984)	(1,353)	(1,051)
Production		(6,344)	(4,285)	(3,585)
Future income tax expense		(5,986)	(4,200)	(3,316)
Future net cash flows		11,963	8,645	7,565
10% discount to reflect timing of cash flows		(5,332)	(4,764)	(3,442)
Standardized measure of discounted future net cash flows	$	6,631	3,881	4,123

		INTERNATIONAL		
		DECEMBER 31,		
		2005	2004	2003
		(IN MILLIONS)		
Future cash inflows	$	12,417	9,338	8,443
Future costs:				
Development		(914)	(689)	(614)
Production		(2,614)	(2,017)	(1,859)
Future income tax expense		(2,960)	(2,052)	(1,914)
Future net cash flows		5,929	4,580	4,056
10% discount to reflect timing of cash flows		(2,262)	(1,750)	(1,761)
Standardized measure of discounted future net cash flows	$	3,667	2,830	2,295

Future cash inflows are computed by applying year-end prices (averaging $45.50 per barrel of oil, $7.84 per Mcf of gas and $32.46 per barrel of natural gas liquids at December 31, 2005) to the year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements in existence at year-end.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. Of the $5.9 billion of future development costs, $1.3 billion, $0.9 billion and $0.6 billion are estimated to be spent in 2006, 2007 and 2008, respectively.

Future development costs include not only development costs, but also future dismantlement, abandonment and rehabilitation costs. Included as part of the $5.9 billion of future development costs are $1.2 billion of future dismantlement, abandonment and rehabilitation costs.

Future production costs include general and administrative expenses directly related to oil and gas producing activities. Future income tax expenses are computed by applying the appropriate statutory tax rates to the future pre-tax net cash flows relating to proved reserves, net of the tax basis of the properties involved. The future income tax expenses give effect to permanent differences and tax credits, but do not reflect the impact of future operations.

Changes Relating to the Standardized Measure of Discounted Future Net Cash Flows

Principal changes in the standardized measure of discounted future net cash flows attributable to Devon's proved reserves are as follows:

	YEAR ENDED DECEMBER 31, 2005	2004	2003
	(IN MILLIONS)		
Beginning balance	$ 16,085	15,921	10,365
Oil, gas and NGL sales, net of production costs	(7,226)	(5,915)	(4,562)
Net changes in prices and production costs	11,787	2,749	2,645
Extensions, discoveries, and improved recovery, net of future development costs	6,200	3,103	2,218
Purchase of reserves, net of future development costs	68	32	5,763
Development costs incurred during the period which reduced future development costs	768	684	1,022
Revisions of quantity estimates	(788)	(1,132)	(728)
Sales of reserves in place	(2,936)	(13)	(307)
Accretion of discount	2,343	2,265	1,531
Net change in income taxes	(4,692)	(1,782)	(2,305)
Other, primarily changes in timing and foreign exchange rates	1,965	173	279
Ending balance	$ 23,574	16,085	15,921

16. SUPPLEMENTAL QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Following is a summary of the unaudited interim results of operations for the years ended December 31, 2005 and 2004.

2005	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	FULL YEAR
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)				
Oil, gas and NGL sales	$ 1,935	2,079	2,299	2,636	8,949
Total revenues	$ 2,351	2,468	2,704	3,218	10,741
Net earnings	$ 563	653	744	970	2,930
Net earnings per common share:					
Basic	$ 1.17	1.40	1.66	2.18	6.38
Diluted	$ 1.14	1.38	1.63	2.14	6.26

2004	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	FULL YEAR
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)				
Oil, gas and NGL sales	$ 1,821	1,842	1,859	1,966	7,488
Total revenues	$ 2,238	2,219	2,267	2,465	9,189
Net earnings	$ 494	502	517	673	2,186
Net earnings per common share:					
Basic	$ 1.03	1.04	1.06	1.38	4.51
Diluted	$ 1.00	1.01	1.03	1.35	4.38

The fourth quarter of 2005 includes a $212 million reduction of carrying value of oil and gas properties and a $14 million income tax benefit due to a statutory rate reduction in Canada. The after-tax effect of the reduction of carrying value was $161 million, or $0.36 per share. The per share effect of the rate reduction tax benefit was $0.03.

The second and fourth quarters of 2004 include a $28 million and $8 million income tax benefit, respectively, due to statutory rate reductions of Canadian tax rates. The per share effect of these tax benefits were $0.06 and $0.01 in the second and fourth quarters of 2004, respectively.

The United States Securities and Exchange Commission requires public companies such as Devon to reconcile Non-GAAP (GAAP refers to generally accepted accounting principles) financial measures to related GAAP measures.

Devon believes that using net debt, defined as debt less cash, short-term investments, and the market value of Chevron common stock, for the calculation of "net debt to adjusted capitalization" provides a better measure than using debt. Devon believes that because cash and short-term investments can be used to repay indebtedness, netting cash and short-term investments against debt provides a clearer picture of the future demands on cash to repay debt. Included in Devon's indebtedness are debentures exchangeable into 14.2 million shares of Chevron common stock owned outright by Devon. Since the Chevron common stock is held by Devon exclusively to satisfy the related debt obligation, Devon believes deducting the market value of the stock provides a clearer picture of future demands on cash to repay debt. This methodology is also utilized by various lenders, rating agencies and securities analysts as a measure of Devon's indebtedness.

RECONCILIATION TO GAAP INFORMATION

		YEAR ENDED DECEMBER 31,				
		2005	2004	2003	2002	2001
				(IN MILLIONS)		
NET DEBT						
Total debt (GAAP)	$	6,619	7,964	8,918	7,562	6,589
Adjustments:						
Cash and short-term investments		(2,286)	(2,119)	(1,273)	(292)	(183)
Investment in Chevron Corporation common stock, at fair value		(805)	(745)	(613)	(472)	(636)
Net Debt (Non-GAAP)	$	3,528	5,100	7,032	6,798	5,770
TOTAL CAPITALIZATION						
Total debt	$	6,619	7,964	8,918	7,562	6,589
Stockholders' equity		14,862	13,674	11,056	4,653	3,259
Total Capitalization (GAAP)	$	21,481	21,638	19,974	12,215	9,848
ADJUSTED CAPITALIZATION						
Net debt	$	3,528	5,100	7,032	6,798	5,770
Stockholders' equity		14,862	13,674	11,056	4,653	3,259
Adjusted Capitalization (Non-GAAP)	$	18,390	18,774	18,088	11,451	9,029

Drill-bit capital is defined as costs incurred less proved acquisition costs, unproved acquisition costs resulting from business combinations, and the net difference of accrued future asset retirement costs less actual cash retirement expenditures. Drill-bit capital is a non-GAAP measure. Management believes drill-bit capital is relevant because it provides additional insight into costs associated with current year drilling, facilities and unproved acreage acquisitions unrelated to business combinations. It should be noted that the actual costs of reserves added through the company's drilling program will differ, sometimes significantly, from the direct comparison of capital spent and reserves added in any given period due to the timing of capital expenditures and reserve bookings. This methodology is also utilized by certain securities analysts as a measure of Devon's performance.

		YEAR ENDED DECEMBER 31,				
		2005	2004	2003	2002	2001
				(IN MILLIONS)		
DRILL-BIT CAPITAL						
Costs Incurred (GAAP)	$	4,139	2,852	8,071	3,764	5,951
Less:						
Proven acquisition costs		54	38	4,209	1,538	3,055
Unproven acquisition costs resulting from business combinations		—	—	1,063	639	1,460
Accrued asset retirement costs (1)		113	51	182	—	—
Plus: Actual retirement expenditures (1)		41	42	37	—	—
Drill-bit capital (Non-GAAP)	$	4,013	2,805	2,654	1,587	1,436

(1) Effective January 1, 2003, Devon adopted SFAS No. 143. Prior to the adoption of SFAS No. 143, asset retirement costs were included in costs incurred when expenditures for such costs were made. Pursuant to the adoption of SFAS No. 143, such costs are now included in costs incurred when a legal obligation for incurring such costs has occurred.

The forward-looking estimates beginning on page 47 are based on management's examination of historical operating trends, the information which was used to prepare the December 31, 2005, reserve reports and other data in Devon's possession or available from third parties. Devon cautions that its future oil, natural gas and NGL production, revenues and expenses are subject to all of the risks and uncertainties normally incident to the exploration for and development, production and sale of oil, gas and NGLs. These risks include, but are not limited to, price volatility, inflation or lack of availability of goods and services, environmental risks, drilling risks, regulatory changes, the uncertainty inherent in estimating future oil and gas production or reserves, and other risks as outlined below. The production, transportation, processing and marketing of oil, natural gas and NGLs are complex processes which are subject to disruption due to transportation and processing availability, mechanical failure, human error, meteorological events including, but not limited to, hurricanes, and numerous other factors.

Price Volatility

Prices for oil, natural gas and NGLs are determined primarily by prevailing market conditions. Market conditions for these products are influenced by regional and worldwide economic conditions, weather and other local market conditions. These factors are beyond Devon's control and are difficult to predict. In addition to volatility in general, oil, gas and NGL prices may vary considerably due to differences between regional markets, differing quality of oil produced (i.e., sweet crude versus heavy or sour crude), differing Btu contents of gas produced, transportation availability and costs and demand for the various products derived from oil, natural gas and NGLs. Substantially all of Devon's revenues are attributable to sales, processing and transportation of these three commodities. Consequently, Devon's financial results and resources are highly influenced by price volatility.

Oil, Gas, and NGL Production

Estimates for future production of oil, natural gas and NGLs are based on the assumption that market demand and prices for oil, gas and NGLs will continue at levels that allow for profitable production of these products. There can be no assurance of such stability. Most of Devon's Canadian production of oil, natural gas and NGLs is subject to government royalties that fluctuate with prices. Thus, price fluctuations can affect reported production. Also, Devon's international production of oil, natural gas and NGLs is governed by payout agreements with the governments of the countries in which Devon operates. If the payout under these agreements is attained earlier than projected, Devon's net production and proved reserves in such areas could be reduced.

Marketing and Midstream

Estimates for future processing and transport of oil, natural gas and NGLs are based on the assumption that market demand and prices for oil, gas and NGLs will continue at levels that allow for profitable processing and transport of these products. There can be no assurance of such stability. Additionally, Devon cautions that its future marketing and midstream revenues and expenses are subject to all of the risks and uncertainties normally incident to the marketing and midstream business. These risks include, but are not limited to, price volatility, environmental risks, regulatory changes, the uncertainty inherent in estimating future processing volumes and pipeline throughput, cost of goods and services and other risks as outlined herein.

Foreign Exchange

Also, the financial results of Devon's foreign operations are subject to currency exchange rate risks. Unless otherwise noted, all of the dollar amounts are expressed in U.S. dollars. Amounts related to Canadian operations have been converted to U.S. dollars using a projected average 2006 exchange rate of $0.87 U.S. dollar to $1.00 Canadian dollar. The actual 2006 exchange rate may vary materially from this estimate. Such variations could have a material effect on our forward-looking estimates.

Property Acquisitions and Dispositions

Although Devon has completed several major property acquisitions and dispositions in recent years, these transactions are opportunity driven. Thus, the forward-looking estimates provided exclude the financial and operating effects of potential property acquisitions or divestitures during the year 2006.

Geographic Reporting Areas for 2006

The estimates of production, average price differentials compared to industry benchmarks and capital expenditures are provided separately for each of the following geographic areas:

- the United States Onshore;
- the United States Offshore, which encompasses all oil and gas properties in the Gulf of Mexico;
- Canada; and
- International, which encompasses all oil and gas properties that lie outside of the United States and Canada.

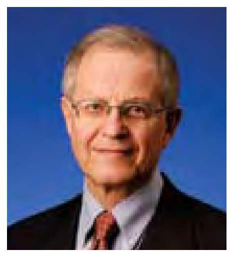
Directors

John W. Nichols, *91*, is a co-founder of Devon. He was named chairman emeritus in 1999. Nichols was chairman of the board of directors from the time Devon began operations in 1971 until 1999. He is a founding partner of Blackwood & Nichols Co., which put together the first public oil and gas drilling fund ever registered with the Securities and Exchange Commission. Nichols is a non-practicing Certified Public Accountant.

J. Larry Nichols, *63*, is a co-founder of Devon. He was named chairman of the board of directors in 2000 and serves as chairman of the Dividend Committee. He has been a director since 1971. Nichols served as president from 1976 until 2003 and has served as chief executive officer since 1980. Nichols serves as a director of Baker Hughes Inc. He also serves as a director of several trade associations that are relevant to the conduct of the company's business. Nichols has a Bachelor of Science degree in geology from Princeton University and a law degree from the University of Michigan.

Thomas F. Ferguson, *69*, joined the board of directors in 1982 and serves as chairman of the Audit Committee. Ferguson retired in 2005 from his position of managing director of United Gulf Management Ltd., a wholly-owned subsidiary of Kuwait Investment Projects Co. KSC. He has represented Kuwait Investment Projects Co. on the boards of various companies in which it invests, including Baltic Transit Bank in Latvia and Tunis International Bank in Tunisia. Ferguson is a Canadian qualified Certified General Accountant and was formerly employed by the Economist Intelligence Unit of London as a financial consultant.

Peter J. Fluor, *58*, joined the board of directors in 2003. Fluor previously served as a director of Ocean Energy Inc. from 1980 to 2003. He has been chairman and chief executive officer of Texas Crude Energy Inc., a private oil and gas company, since January 2001. From 1997 through 2000, Fluor was president and chief executive officer of Texas Crude Energy Inc. He also serves on the board of Cooper Cameron Corp. and serves as lead independent director of Fluor Corp.



David M. Gavrin, *71*, joined the board of directors in 1979 and serves as lead director and chairman of the Compensation Committee. Gavrin has been a private investor since 1989 and is currently a director and chairman of the board of MetBank Holding Corp. He is also a director of Arthur J. Gavrin Foundation Inc. From 1978 to 1988, he was a general partner of Windcrest Partners, a private investment partnership in New York City. For 14 years prior to that, he was an officer of Drexel Burnham Lambert Inc.

John A. Hill, *64*, joined the board of directors in 2000 following Devon's merger with Santa Fe Snyder Corp. He is chairman of the Governance Committee. Hill has been with First Reserve Corp., an oil and gas investment management company, since 1983 and is currently its vice chairman and managing director. Prior to creating First Reserve Corp., Hill was president and chief executive officer of several investment banking and asset management companies and served as the deputy administrator of the Federal Energy Administration during the Ford Administration. Hill is chairman of the board of trustees of the Putnam Funds in Boston, a trustee of Sarah Lawrence College and a director of TransMontaigne Inc. and various companies controlled by First Reserve Corp.

Directors

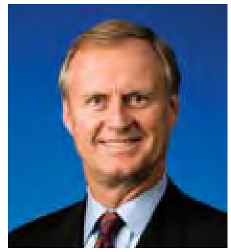
Robert L. Howard, *69*, joined the board of directors in 2003 and serves as chairman of the Reserves Committee. Howard previously served as a director of Ocean Energy Inc. He retired in 1995 from his position as vice president of Domestic Operations, Exploration and Production, of Shell Oil Co. Howard is also a director of Southwestern Energy Co. and McDermott International Inc.

William J. Johnson, *71*, joined the board of directors in 1999. Johnson has been a private consultant in the oil and gas industry for more than six years. He is president and a director of JonLoc Inc., an oil and gas company of which he and his family are the only stockholders. Johnson has served as a director of Tesoro Petroleum Corp. since 1996. From 1991 to 1994, Johnson was president, chief operating officer and a director of Apache Corp.

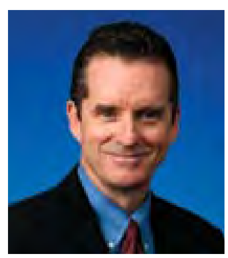
Michael M. Kanovsky, *57*, joined the board of directors in 1998. Kanovsky was a co-founder of Northstar Energy Corp., acquired by Devon in 1998, and served on Northstar's board of directors from 1982 to 1998. He is president of Sky Energy Corp. and serves as a director of Kinwest Energy Corp. and North American Oil Sands Corp., all privately held energy corporations. Kanovsky also currently serves as a director of several publicly traded companies, including Accrete Energy Inc., ARC Resources Ltd., Bonavista Petroleum Ltd., Pure Technologies Ltd. and TransAlta Corp.

J. Todd Mitchell, *47*, joined the board of directors in 2002. Mitchell previously served on the board of directors of Mitchell Energy & Development Corp. from 1993 to 2002. He has served as president of GPM Inc., a family-owned investment company, since 1998. Mitchell has also served as president of Dolomite Resources Inc., a privately owned mineral exploration and investments company, since 1987, and as chairman of Rock Solid Images, a privately-owned seismic data analysis software company, since 1998.

Senior Officers

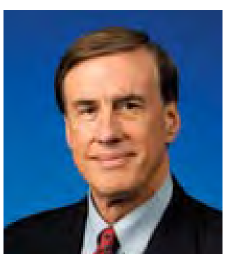


John Richels, *55*, was elected president of Devon in 2004. He previously served as a senior vice president of Devon and president and chief executive officer of Devon's Canadian subsidiary. Richels joined Devon through its 1998 acquisition of Canadian-based Northstar Energy Corp., where he held the position of executive vice president and chief financial officer from 1996 to 1998 and served on the board of directors from 1993 to 1996. Prior to joining Northstar, Richels was managing partner, chief operating partner and a member of the executive committee of the Canadian based national law firm, Bennett Jones. Richels previously served as a director of a number of publicly traded companies and is former vice-chairman of the board of governors of the Canadian Association of Petroleum Producers. He holds a bachelor's degree in economics from York University and a law degree from the University of Windsor. While employed by Bennett Jones in the 1980s, Richels served as general counsel of the XV Olympic Winter Games Organizing Committee in Calgary.



Stephen J. Hadden, *51*, was named senior vice president, Exploration and Production, in 2004. Prior to joining Devon, Hadden was with Texaco, now Chevron Corporation. He joined that company as a field engineer in 1977 and subsequently held a series of engineering and management positions with increasing responsibility in the United States. His tenure with Texaco included assignments as assistant to the president of Texaco Exploration and Production; division manager for the Bakersfield Producing Division; and assistant to the chairman of the board of Texaco, where he assisted executive management with the oversight of the company's worldwide business in more than 140 countries. He also served as vice president of Texaco Exploration and Production, which included responsibility for the company's western region, and then served as vice president of the California Business Unit. In 2002, he became an independent consultant. Hadden holds a bachelor's degree in chemical engineering from Pennsylvania State University.

Brian J. Jennings, *45*, was elected to the position of senior vice president, Corporate Finance and Development, and chief financial officer in 2004. He served as senior vice president, Corporate Finance and Development, from 2001 to March 2004. Jennings joined Devon in 2000 as vice president of Corporate Finance. Prior to joining Devon, Jennings was a managing director in the Energy Investment Banking Group of PaineWebber Inc. He began his banking career at Kidder, Peabody in 1989 before moving to Lehman Brothers in 1992 and later to PaineWebber in 1997. Jennings specialized in providing strategic advisory and corporate finance services to public and private companies in the exploration and production and oilfield service sectors. He started his energy career with ARCO International Oil & Gas, a subsidiary of Atlantic Richfield Co. Jennings received his Bachelor of Science degree in petroleum engineering from the University of Texas at Austin and his Master of Business Administration degree from the University of Chicago's Graduate School of Business.



Duke R. Ligon, *64*, was elected to the position of senior vice president and general counsel in 1999. Ligon had previously joined Devon as vice president and general counsel in 1997. In addition to Ligon's primary role of managing Devon's corporate legal matters (including litigation), he has direct involvement with Devon's governmental affairs and its merger and acquisition activities. Prior to joining Devon, Ligon practiced energy law for 12 years and last served as a partner at the law firm of Mayer, Brown & Platt (now Mayer, Brown, Rowe & Maw) in New York City. In addition, he was a senior vice president and managing director for investment banking at Bankers Trust Co. in New York City for 10 years. Ligon also served for three years in various positions with the U.S. Departments of the Interior and Treasury as well as the Department of Energy. Ligon holds an undergraduate degree in chemistry from Westminster College and a law degree from the University of Texas School of Law.

Marian J. Moon, *55*, was elected to the position of senior vice president, Administration, in 1999. Moon is responsible for Human Resources, Office Administration, Business Information and Technology, Corporate Resources and Corporate Governance. Moon has been with Devon for 21 years serving in various capacities, including manager of Corporate Finance and corporate secretary. Prior to joining Devon, Moon was employed for 11 years by Amarex Inc., an Oklahoma City-based oil and natural gas production and exploration firm. Her last position with Amarex was as treasurer. Moon is a member of the Society of Corporate Secretaries & Governance Professionals. She is a graduate of Valparaiso University.

Darryl G. Smette, *58*, was elected to the position of senior vice president, Marketing and Midstream, in 1999. Smette previously held the position of vice president, Marketing and Administrative Planning, since 1989. He joined Devon in 1986 as manager of Gas Marketing. His marketing background includes 15 years with Energy Reserves Group/BHP Petroleum (Americas) Inc., where he last served as director of Marketing. Smette is also an oil and gas industry instructor, approved by the University of Texas Department of Continuing Education. Smette is a member of the Oklahoma Independent Producers Association, Natural Gas Association of Oklahoma and the American Gas Association. He holds an undergraduate degree from Minot State University and a master's degree from Wichita State University.

Glossary

Bitumen / A viscous, tar-like oil that requires nonconventional production methods such as mining or steam-assisted gravity drainage.
Block / Refers to a contiguous leasehold position. In federal offshore waters, a block is typically 5,000 acres.
British thermal unit (Btu) / A measure of heat value. An Mcf of natural gas is roughly equal to one million Btu.
Coalbed natural gas / An unconventional gas resource that is present in certain coal deposits.
Deep water / In offshore areas, water depths of greater than 600 feet.
Delineation well / A well drilled just outside the proved area of an oil or gas reservoir in an attempt to extend the known boundaries of the reservoir.
Development well / A well drilled within the area of an oil or gas reservoir known to be productive. Development wells are relatively low risk.
Dry hole / A well found to be incapable of producing oil or gas in sufficient quantities to justify completion.
Exploitation / Various methods of optimizing oil and gas production or establishing additional reserves from producing properties through additional drilling or the application of new technology.
Exploratory well / A well drilled in an unproved area, either to find a new oil or gas reservoir or to extend a known reservoir. Sometimes referred to as a wildcat.
Field / A geographical area under which one or more oil or gas reservoirs lie.
Floating production, storage and offloading unit (FPSO) / A moored tanker-type vessel used to develop an offshore oil field. Oil is stored within the FPSO until offloaded to a tanker for transportation to a terminal or refinery.
Formation / An identifiable layer of rocks named after the geographical location of its first discovery and dominant rock type.
Fracture, refracture / The process of applying hydraulic pressure to an oil or gas bearing geological formation to crack the formation and stimulate the release of oil and gas.
Gross acres / The total number of acres in which one owns a working interest.
Hedge / A financial contract entered into to manage commodity price risk.
Increased density/infill / A well drilled in addition to the number of wells permitted under initial spacing regulations, used to enhance or accelerate recovery, or prevent the loss of proved reserves.
Independent producer / A non-integrated oil and gas producer with no refining or retail marketing operations.
Lease / A legal contract that specifies the terms of the business relationship between an energy company and a landowner or mineral rights holder on a particular tract.
London Inter Bank Offering Rate (LIBOR) / An average of the interest rate on dollar-denominated deposits, also known as Eurodollars, traded between banks in London.
Natural gas liquids (NGLs) / Liquid hydrocarbons that are extracted and separated from the natural gas stream. NGL products include ethane, propane, butane and natural gasoline.
Net acres / Gross acres multiplied by one's fractional working interest in the property.
New York Mercantile Exchange (NYMEX) / The world's largest physical commodity futures exchange. The prices quoted for oil, gas and other commodity transactions on the exchange are the basis for prices paid throughout the world.
Oil sands / A complex mixture of sand, water and clay trapping very heavy oil known as bitumen.
Pilot program / A small-scale test project used to assess the viability of a concept prior to committing significant capital to a large-scale project.
Production / Natural resources, such as oil or gas, taken out of the ground.
Gross production / Total production before deducting royalties.
Net production / Gross production, minus royalties, multiplied by one's fractional working interest.
Prospect / An area designated for the potential drilling of development or exploratory wells.
Proved reserves / Estimates of oil, gas and NGL quantities thought to be recoverable from known reservoirs under existing economic and operating conditions.
Recavitate / The process of applying pressure surges on the coal formation at the bottom of a well in order to increase fracturing, enlarge the bottomhole cavity and thereby increase gas production.
Recompletion / The modification of an existing well for the purpose of producing oil or gas from a different producing formation.
Reservoir / A rock formation or trap containing oil and/or natural gas.
Royalty / The owner's share of the value of minerals (oil and gas) produced on the property.
Seismic / A tool for identifying underground accumulations of oil or gas by sending energy waves or sound waves into the earth and recording the wave reflections. Results indicate the type, size, shape and depth of subsurface rock formations. 2-D seismic provides two-dimensional information while 3-D creates three dimensional pictures. 4-C, or four-component, seismic utilizes measurement and interpretation of shear wave data. 4-C seismic improves the resolution of seismic images below shallow gas deposits.
Steam-assisted gravity drainage (SAGD) / A method of extracting bitumen from oil sands. Steam is injected under ground, softening the bitumen and allowing it to flow to the surface.
Undeveloped acreage / Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas.
Unit / A contiguous parcel of land deemed to cover one or more common reservoirs, as determined by state or federal regulations. Unit interest owners generally share proportionately in costs and revenues.
Waterflood / A method of increasing oil recoveries from an existing reservoir. Water is injected through a special "water injection well" into an oil producing formation to force additional oil out of the reservoir rock and into nearby oil wells.
Working interest / The cost-bearing ownership share of an oil or gas lease.
Workover / The process of conducting remedial work, such as cleaning out a well bore, to increase or restore production.

VOLUME ACRONYMS

Bbl / A standard oil measurement that equals one barrel (42 U.S. gallons).
MBbl / One thousand barrels
MMBbl / One million barrels
Mcf / A standard measurement unit for volumes of natural gas that equals one thousand cubic feet.
MMcf / One million cubic feet
Bcf / One billion cubic feet
MMcfd / Millions of cubic feet of gas per day
Boe / A method of equating oil, gas and natural gas liquids. Gas is converted to oil based on its relative energy content at the rate of six Mcf of gas to one barrel of oil. NGLs are converted based upon volume: one barrel of natural gas liquids equals one barrel of oil.
MBoe / One thousand barrels of oil equivalent
MMBoe / One million barrels of oil equivalent

Common Stock Trading Data

2004

QUARTER	HIGH	LOW	LAST	TOTAL VOLUME
First	$ 30.56	25.88	29.08	195,907,400
Second	$ 33.75	28.68	33.00	183,259,600
Third	$ 37.90	31.61	35.51	189,934,000
Fourth	$ 41.64	34.55	39.03	196,976,100

2005

QUARTER	HIGH	LOW	LAST	TOTAL VOLUME
First	$ 49.42	36.48	47.75	195,070,400
Second	$ 52.31	40.60	50.68	222,165,200
Third	$ 70.35	50.75	68.64	184,169,700
Fourth	$ 69.79	54.01	62.54	246,835,700

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Shareholder Assistance
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Publications
A copy of Devon's annual report to the Securities and Exchange Commission (Form 10-K) and other publications are available at no charge upon request. Direct requests to:
Judy Roberts
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Fax: (405) 552-7818
E-mail: judy.roberts@dvn.com

Annual Meeting
Our annual shareholders' meeting will be held at 8 a.m. Central Time on Wednesday, June 7, 2006, on the Third Floor of the Chase Tower, 100 North Broadway, Oklahoma City, OK.

Independent Auditors
KPMG LLP
Oklahoma City, OK

Stock Trading Data
Devon Energy Corporation's common stock is traded on the New York Stock Exchange (symbol: DVN). There are approximately 17,000 shareholders of record.

Forward-Looking Statements / This annual report includes "forward-looking statements" as defined by the Securities and Exchange Commission. Such statements are those concerning Devon's plans, expectations and objectives for future operations including reserve potential and exploration target size. These statements address future financial position, business strategy, future capital expenditures, projected oil and gas production and future costs. Devon believes that the expectations reflected in such forward-looking statements are reasonable. However, important risk factors could cause actual results to differ materially from the company's expectations. A discussion of these risk factors can be found on page 99 of this report. Further information is available in the company's Form 10-K and other publicly available reports, which are available free of charge on the company's website, www.devonenergy.com, or will be furnished upon request to the company.

How do *you* define Devon?