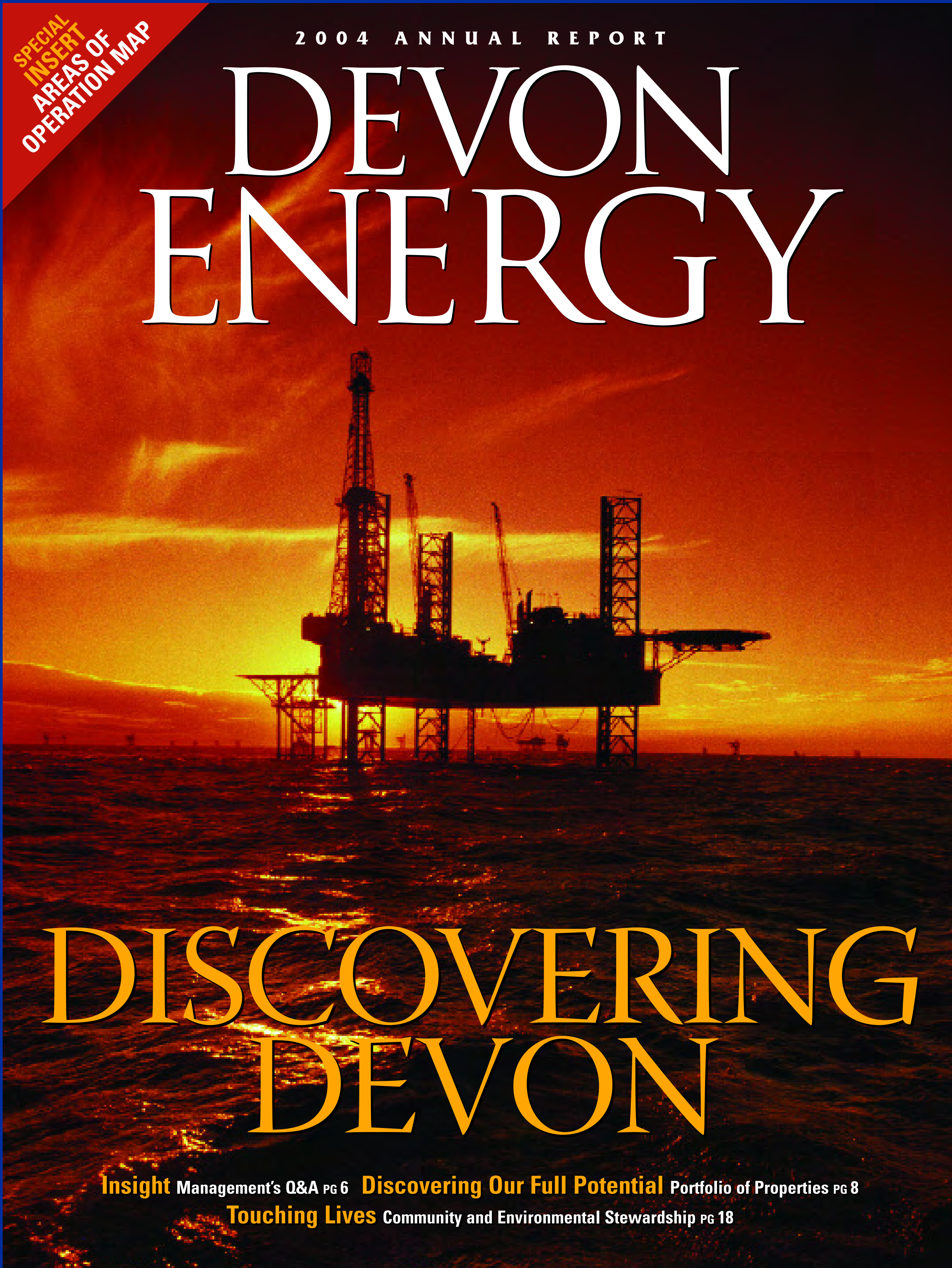
SPECIAL INSERT AREAS OF OPERATION MAP

2004 ANNUAL REPORT

DEVON ENERGY



DISCOVERING DEVON

About this Issue

Discovering Devon is our 2004 Annual Report. Inside, our Chairman and CEO, Larry Nichols, summarizes 2004 and his view of our future. You also will see facts, figures and charts about Devon's performance last year with comparisons to previous years. We have included descriptions of many of our oil and gas projects and examples of our contributions to the communities where we do business. You will also find financial statements, detailed notes explaining them and the report of our auditors. All of this is typical content for an annual report.

This annual report was designed, however, to look and feel like a magazine—a magazine of discovery. The theme, *Discovering Devon*, was selected from about 1,000 employee submissions. Cab Craig, an engineer in Devon's Gulf Division in Houston, submitted the winning theme.

Please take a few minutes to page through this report. In keeping with its theme of discovery, this book is intended to help you discover something new about Devon. We are excited about our company and our accomplishments. And we are proud of our values and our employees who live them. That pride is reflected within the pages of this report. We hope you enjoy it.

Just as discovery is the aim of exploratory drilling, our aim with this annual report is to lead you in a discovery of Devon.

Touching Lives — PG 18

FEATURES

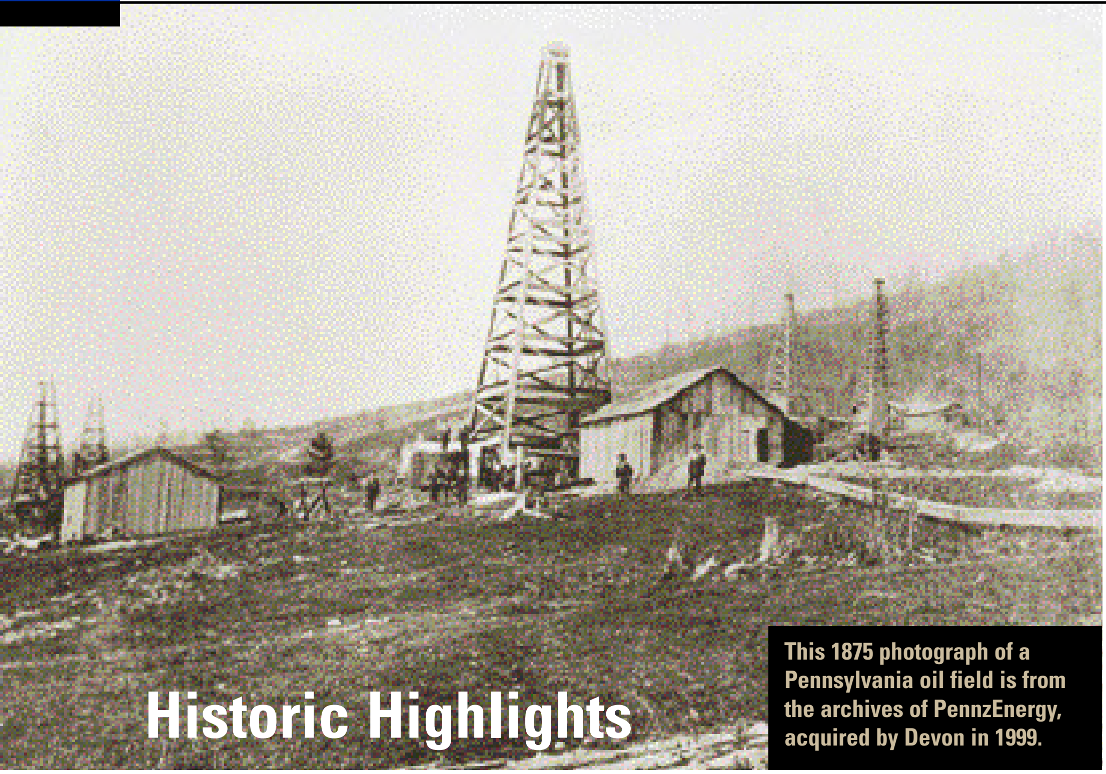
In the above photo, Devon employees Tim Raley (left) and George Jackson bring the message of oilfield safety to high school students in Bridgeport, Texas.

DEPARTMENTS

COVER
Much of the earth's undiscovered oil and gas reserves are believed to lie beneath its oceans. This offshore rig is at work in the Gulf of Mexico.

MISSION

Devon Energy is a results-oriented oil and gas company that builds value for our shareholders through its employees by creating an atmosphere of optimism, teamwork, creativity and resourcefulness and by dealing with everyone in an open and ethical manner.



Historic Highlights

This 1875 photograph of a Pennsylvania oil field is from the archives of PennzEnergy, acquired by Devon in 1999.

2005

2004 – Devon's stock price hits all-time high.
– Devon initiates $1.5 billion non-core property divestiture program and begins repurchasing up to 10% of its common stock.
– Devon declares a two-for-one stock split and transfers its common stock listing to the New York Stock Exchange.
– Quarterly cash dividend increased to five cents per common share.

2003 – Devon's $5.3 billion merger with Ocean Energy creates the largest U.S.-based independent oil and gas producer with 4,000 employees worldwide.

2002 – Devon acquires Mitchell Energy for $3.5 billion, adding the prolific Barnett Shale play in north Texas to its core assets and establishing the company as a leading independent processor of natural gas and natural gas liquids.
– Devon named to the Fortune 500.

2001 – Acquisition of Anderson Exploration for $4.6 billion positions Devon as the third-largest independent gas producer in Canada.
– Devon combines its marketing and midstream operations creating a new division.

2000 – Devon merges with Santa Fe Snyder creating a top five U.S.-based independent. The $3.5 billion transaction expands Devon's international presence.
– President and CEO Larry Nichols named Chairman of the Board.
– Devon named to S&P 500 Index.

1999 – The $2.6 billion acquisition of PennzEnergy establishes Devon as a significant offshore Gulf of Mexico operator.
– Employee count reaches 1,500 worldwide.

1998 – Devon acquires Northstar Energy for $750 million, creating a top 15 U.S.-based independent.

1996 – Devon acquires Kerr-McGee's North American onshore oil and gas properties for $250 million, increasing the company's reserves by 46%.
– Quarterly cash dividend increased to 2.5 cents per common share.

1993 – Devon declares its first quarterly cash dividend of 1.5 cents per common share.

1992 – Acquisition of Hondo Oil & Gas for $122 million sets the stage for a series of major acquisitions in the years to come.

1989 – Devon begins production of coalbed natural gas in the San Juan Basin.

1988 – Devon becomes a public company, listing on the American Stock Exchange under the ticker symbol DVN.

1981 – Devon, with 185 employees, relocates corporate headquarters to present downtown Oklahoma City location.

1971 – Devon founded by John Nichols and his son Larry.

1950 – Devon co-founder, John Nichols, creates the first public oil and gas drilling fund registered with the Securities and Exchange Commission.

2000 · 1995 · 1990 · 1985 · 1980 · 1975 · 1970 · 1965 · 1950

2004
ANNUAL REPORT

DEVON ENERGY

COMPANY PROFILE Devon is engaged in oil and gas exploration, production and property acquisitions. Devon is the largest U.S.-based independent oil and gas producer and is one of the largest independent processors of natural gas and natural gas liquids in North America. The company also has operations in select international areas. Devon is included in the S&P 500 Index and its common shares trade on the New York Stock Exchange under the ticker symbol DVN.

Devon's primary goal is to build value per share by:

- Exploring for undiscovered oil and gas reserves,
- Purchasing and exploiting producing oil and gas properties,
- Enhancing the value of our production through marketing and midstream activities,
- Optimizing production operations to control costs, and
- Maintaining a strong balance sheet.

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 in the "Management's Discussion and Analysis ..." section 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.

Five-Year Highlights

Year Ended December 31,		2000	2001	2002	2003	2004	LAST YEAR CHANGE
FINANCIAL DATA (1) (Millions, except per share data)							
Total revenues (2)	$	2,587	2,864	4,316	7,352	9,189	25%
Operating costs and expenses		1,431	2,672	3,775	4,710	5,485	16%
Earnings from operations		1,156	192	541	2,642	3,704	40%
Other expenses		118	164	675	397	411	3%
Total income tax expense (benefit)		377	5	(193)	514	1,107	115%
Net earnings from continuing operations		661	23	59	1,731	2,186	26%
Net results of discontinued operations		69	31	45	—	—	NM
Cumulative effect of change in accounting principle		—	49	—	16	—	NM
Net earnings		730	103	104	1,747	2,186	25%
Preferred stock dividends		10	10	10	10	10	—
Net earnings applicable to common stockholders	$	720	93	94	1,737	2,176	25%
Net earnings per share:							
Basic	$	2.83	0.37	0.31	4.16	4.51	8%
Diluted	$	2.75	0.36	0.30	4.04	4.38	8%
Weighted average common shares outstanding:							
Basic		255	255	309	417	482	16%
Diluted		263	259	313	433	499	15%
Cash flows from continuing operating activities	$	1,479	1,776	1,726	3,768	4,816	28%
Operating cash flows from discontinued operations		110	134	28	—	—	NM
Net cash provided by operating activities	$	1,589	1,910	1,754	3,768	4,816	28%
Cash dividends per common share (3)	$	0.09	0.10	0.10	0.10	0.20	100%

December 31,		2000	2001	2002	2003	2004	LAST YEAR CHANGE
Total assets	$	6,860	13,184	16,225	27,162	29,736	9%
Debentures exchangeable into shares of ChevronTexaco Corporation common stock (4)	$	760	649	662	677	692	2%
Other long-term debt	$	1,289	5,940	6,900	7,903	6,339	(20%)
Stockholders' equity	$	3,277	3,259	4,653	11,056	13,674	24%
Working capital	$	251	435	22	293	483	65%
PROPERTY DATA (1)							
Proved reserves (Net of royalties)							
Oil (MMBbls)		406	527	444	661	596	(10%)
Gas (Bcf)		3,045	5,024	5,836	7,316	7,494	2%
NGLs (MMBbls)		50	108	192	209	232	11%
Oil, Gas and NGLs (MMBoe) (5)		963	1,472	1,609	2,089	2,077	(1%)

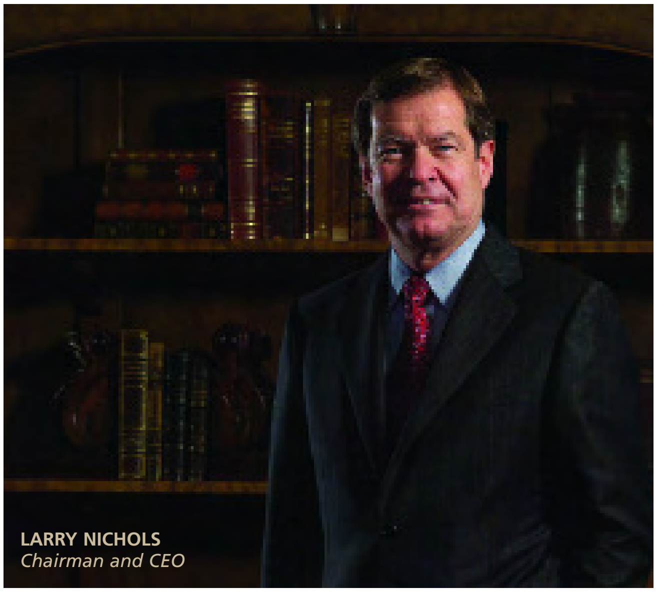
Year Ended December 31,	2000	2001	2002	2003	2004	LAST YEAR CHANGE
Production (Net of royalties)						
Oil (MMBbls)	37	36	42	62	78	26%
Gas (Bcf)	417	489	761	863	891	3%
NGLs (MMBbls)	7	8	19	22	24	10%
Oil, Gas and NGLs (MMBoe) (5)	113	126	188	228	251	10%

(1) Years 2000 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. Data for 2000 has been reclassified to reflect the 2000 merger of Devon and Santa Fe Snyder in accordance with the pooling-of-interests method of accounting. 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) Excludes other income, which is netted against other expense.
(3) The cash dividend per share presented for 2000 is not representative of the actual amount paid by Devon because of the Santa Fe Snyder merger accounted for as a pooling-of-interests. For the year 2000, Devon paid cash dividends of $0.10 per share.
(4) Debentures exchangeable into 14.2 million shares of ChevronTexaco common stock beneficially owned by Devon.
(5) Gas converted to oil at the ratio of 6Mcf:1Bbl. Natural gas liquids converted to oil at the ratio of 1Bbl:1Bbl.
NM Not a meaningful number.

Dear Fellow Shareholders:

For Devon Energy Corporation, 2004 was a year of outstanding achievement. As demonstrated by these key financial and operating metrics, the company delivered yet another record-breaking performance:

- **Net earnings climbed to $2.2 billion, or $4.38 per share, an all-time record.**
- **Total revenues soared to $9.2 billion, up 25% over our previous record set in 2003.**
- **Cash flow from operations grew 28% over 2003, to $4.8 billion, also an all-time record.**
- **Oil, gas and natural gas liquids production climbed 10%, to a record 251 million equivalent barrels.**
- **With drill-bit capital expenditures of $2.8 billion, we added 313 million barrels of oil and gas reserves through discoveries, extensions and performance revisions.**



LARRY NICHOLS
Chairman and CEO

Devon's 2004 financial performance allowed us to fully fund a robust capital program while simultaneously strengthening our balance sheet. We funded total capital expenditures of $3.1 billion, repaid almost $1 billion in debt and increased our cash and short-term investments to $2.1 billion at year-end. By the end of 2004, we had provided for all debt maturities through 2007. Furthermore, Devon's net debt to adjusted capitalization ratio declined during the year to a comfortable 27%.

Yes, the key metrics reflect that 2004 was the best year in Devon's history. And yet, one must look beyond these numbers to discover many of the year's most important achievements.

During 2004, we began to reap the rewards of our long-term value creation strategy. Devon's foundation of high-quality North American oil and gas assets delivered profitable production and reserve additions. Onshore, in North America, we drilled 2,089 oil and gas wells with a 97% success rate. We increased production organically and added more oil and gas reserves than we produced.

In addition to funding the projects that delivered our 2004 reserves and production growth, our core North American properties generated significant quantities of excess cash. This excess cash allowed us to make significant long-term investments as well. After years of investing in these longer-term projects, we are now beginning to realize the benefits. In late 2004, we received regulatory approval for our Jackfish thermal heavy oil project in Alberta. We expect to begin booking oil reserves from Jackfish in 2005 and to see first production in 2007. When fully operational in 2008, this 100% Devon-owned project is expected to deliver 35,000 barrels of oil per day, without decline, for more than 20 years. Also during 2004, we made our third discovery in the emerging lower Tertiary play in the deepwater Gulf of Mexico. In 2005, we plan to delineate these discoveries and to continue to explore for new ones. In addition, we expect to test several high-impact prospects off the coast of West Africa this year. These wells are the culmination of years of preparatory work.

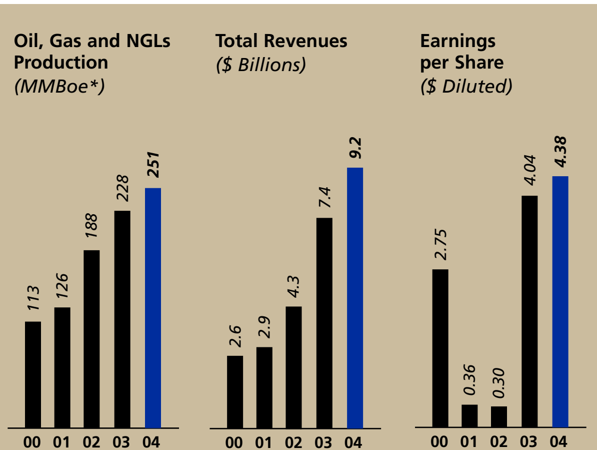
Such long-term investments hold the promise to deliver significant additions of oil and gas reserves and production well into the next decade. While the first cash outlays were made years in advance of any possible contribution to production or earnings, these investments captured significant value. They underscore our commitment to manage Devon to achieve sustainable success over the long run.

Devon's commitment to long-term value creation is also reflected in recent decisions to upgrade our asset base. Since 2002, we have divested $330 million of non-core midstream assets. And in late 2004, we announced the decision to divest non-core oil and gas properties representing about 15% of our 2004 production. This decision was a result of our disciplined, fact-based approach to strategic planning. Throughout our history, we have periodically purged properties that no longer fit our portfolio. The sale of these non-core properties and the redeployment of the capital enhances our ability to create value over a longer time horizon. Following the divestitures, our efforts will be focused on a property base with lower operating costs, better capital efficiency and greater growth potential.

Another 2004 accomplishment not reflected in the numbers is the realignment and reinforcement of our senior management team. In July 2004, Steve Hadden joined the company as senior vice president of exploration and production. He brings to Devon more than two decades of industry management experience. His influence on our operations is already being felt as Steve focuses his technical teams on creating incremental value throughout the exploration and production cycle.

Steve's hiring followed two other senior management changes in early 2004. John Richels, previously head of Devon's Canadian Division, relocated to Oklahoma City after being named Devon's president. Brian Jennings, senior vice president, assumed the additional responsibilities of chief financial officer.

Perhaps Devon's greatest accomplishment throughout our history has been the preservation of our culture. While we have grown into a sizeable company, with "large-company" assets, we have maintained a small company culture. We are relatively free of the politics, red tape and bureaucracy that can endanger the spirit of a large organization. And we continue to approach our business with the freedom to be creative and the power of teamwork.



Production of oil, gas and NGLs climbed to a record 251 million equivalent barrels...

...driving revenues to a record $9.2 billion...

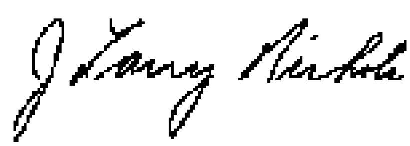
...and earnings per share to the highest level in Devon's history.

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

As I look forward to 2005 and beyond, I see a future even brighter than our past. The world has entered a period where oil and gas are becoming increasingly scarce and valuable commodities. Devon is positioned to benefit from this environment with a large and profitable North American production base that provides dependable reserves and production growth. We are fortunate to have assembled an inventory of large-scale development projects that will provide low-risk growth opportunities through the remainder of this decade. This stable base is complemented by a dynamic, risk-balanced exploration program that provides exposure to some of the highest potential areas in the world. And we have the technical, financial and human resources to compete anywhere we choose.

During the first half of 2005, we expect to realize about $1.5 billion in after-tax proceeds from our property divestitures. In addition, assuming oil and gas prices remain relatively strong, we will generate cash flow far in excess of our 2005 capital demands. We are committed to using these funds to generate incremental value per share. We can accomplish this through stock repurchases, debt reduction, dividends and incremental investments. We recognize that our asset divestiture program will reduce near-term production and earnings. However, we are confident our shareholders will ultimately be rewarded for our focus on optimizing net value per share over the longer term. Furthermore, we are convinced that our collective patience will be well rewarded as Devon's existing project inventory delivers significant top-line production growth over the coming years.

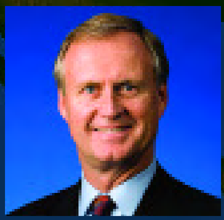
The theme of this 2004 annual report is *Discovering Devon.* The balance of the publication offers glimpses into the properties, the people, the strategies and the values that define our company. I invite you to explore these pages in order to know us better. I invite you to Discover Devon.



J. LARRY NICHOLS
Chairman and Chief Executive Officer
March 11, 2005

INSIGHT

Devon added significant new reserves with the drill-bit at a low unit cost in 2004. Can we expect Devon to repeat this performance in the future?



JOHN RICHELS: Yes, we are pleased with our drilling results in 2004 and are confident we will deliver attractive results in the future. Devon has invested heavily for several years to assemble a high-impact, risk-balanced exploration portfolio. This portfolio has been constructed to provide consistent, economic results in the future. The positive impact of these long cycle-time projects coupled with repeatable growth from Devon's core North American onshore assets, should allow us to continue to grow our reserve base with attractive unit costs.

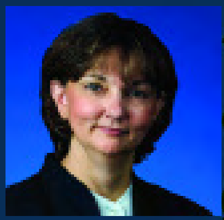
Although drilling program results can vary considerably from one year to the next, multi-year results should reflect the program's true performance. We are confident Devon's balanced approach of combining low-risk, near-term projects with high-impact exploration will deliver competitive results over the long run.

When can we expect to see reserve additions and oil production from your lower Tertiary discoveries in the Walker Ridge area of the deep-water Gulf of Mexico?

STEVE HADDEN: Devon has announced three discoveries in the Walker Ridge area. The Cascade, St. Malo and Jack discoveries are all in water depths greater than 7,000 feet and each is more than 100 miles from land. The development of these discoveries in such remote and inhospitable environments clearly requires a great deal of advance planning and capital investment. Deepwater technology is advancing rapidly, enabling us to consider a variety of development options for these discoveries. We have begun preliminary engineering but still require more information prior to committing to a development plan.

In 2005, we plan to drill delineation wells on each of these three discoveries. We may also conduct a production test to obtain additional information. Such a test would require drilling and completing a well and producing oil from it for a sustained period. Sustained tests are difficult and costly in deep water, but we believe a test is justified given the significance of these projects. Reserve bookings could follow a successful production test in a matter of a few months. Depending on the development option selected, construction would probably require two or three additional years prior to first production.

With the energy industry's current strength, there is increasing competition among companies to attract and retain employees. How is Devon responding to this competition?



MARIAN MOON: As Devon grew through mergers and acquisitions, we retained the best elements of the acquired companies' employee benefits and retention programs. Consequently, we offer industry-leading working conditions and benefits to our personnel. These programs include competitive long-term incentives that reward employees for their continued commitment to Devon. We also invest heavily in continuing education and training programs that enable employees to refresh and upgrade their skills and to position themselves for advancement.

In the future, the oil and gas industry will be challenged by the lack of an adequate pool of prospective employees with petroleum industry related degrees. Devon has made a strong commitment to meet that challenge by investing in higher education. In 2004 and early 2005, the company made significant financial commitments to higher education. These gifts will fund teaching and research facilities in Devon's name. Also in 2004, we enhanced our college internship and recruiting programs targeting promising students as potential employees. We believe these investments will encourage young people to pursue oil and gas careers and to consider Devon for employment upon graduation.

Members of Devon's management answer your questions to provide insight into our strategy.

The company has committed to repurchase about 10% of its common stock. Why did you choose this use of cash rather than increasing exploration and development expenditures?

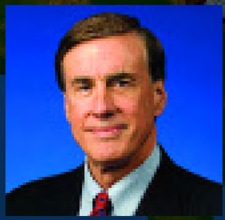
BRIAN JENNINGS:

Devon's number one objective is to maximize value per share. We continuously evaluate investment alternatives and select the mix that we believe will best achieve this objective. Repurchasing stock is but one such alternative. We have not selected it to the detriment of our exploration and development programs. We are funding our capital programs at optimum levels while utilizing the excess cash to concurrently repurchase stock, reduce debt and pay cash dividends.

Share repurchases can also have certain advantages over other investment alternatives. Reducing the number of outstanding shares increases every stockholder's share of ownership in the company. Furthermore, when repurchasing Devon's shares, we are investing in our own high-quality asset base. This has definite advantages because we know and understand these assets, and we incur no integration risks or costs.

2004 was the first year in many that Devon did not complete a significant merger or acquisition. Is Devon out of the M&A market permanently?

DUKE LIGON:



Mergers and acquisitions have played an important role in Devon's dramatic growth since going public in 1988. However, as evidenced by our willingness to periodically divest producing properties, growth for growth's sake was never our goal. We believed that we could take advantage of this period of rapid industry consolidation to build value per share. Concurrently, we wanted to create a company capable of sustainable organic growth when industry consolidation slowed down, or the economics of acquisitions eroded.

This is exactly where Devon is today. Devon has assembled the assets, the expertise and the financial capacity to grow—without additional acquisitions. Our North American core assets consistently provide low-risk, short cycle-time reserve and production additions. These are complemented by a significant inventory of risk-balanced, high-impact exploration projects that provide longer term growth opportunities.

Does this mean we will never make another acquisition? Probably not. Evaluating, structuring and integrating acquisitions are among Devon's core competencies. Should an opportunity become available that is earnings accretive and strategically attractive, we will not hesitate to move.

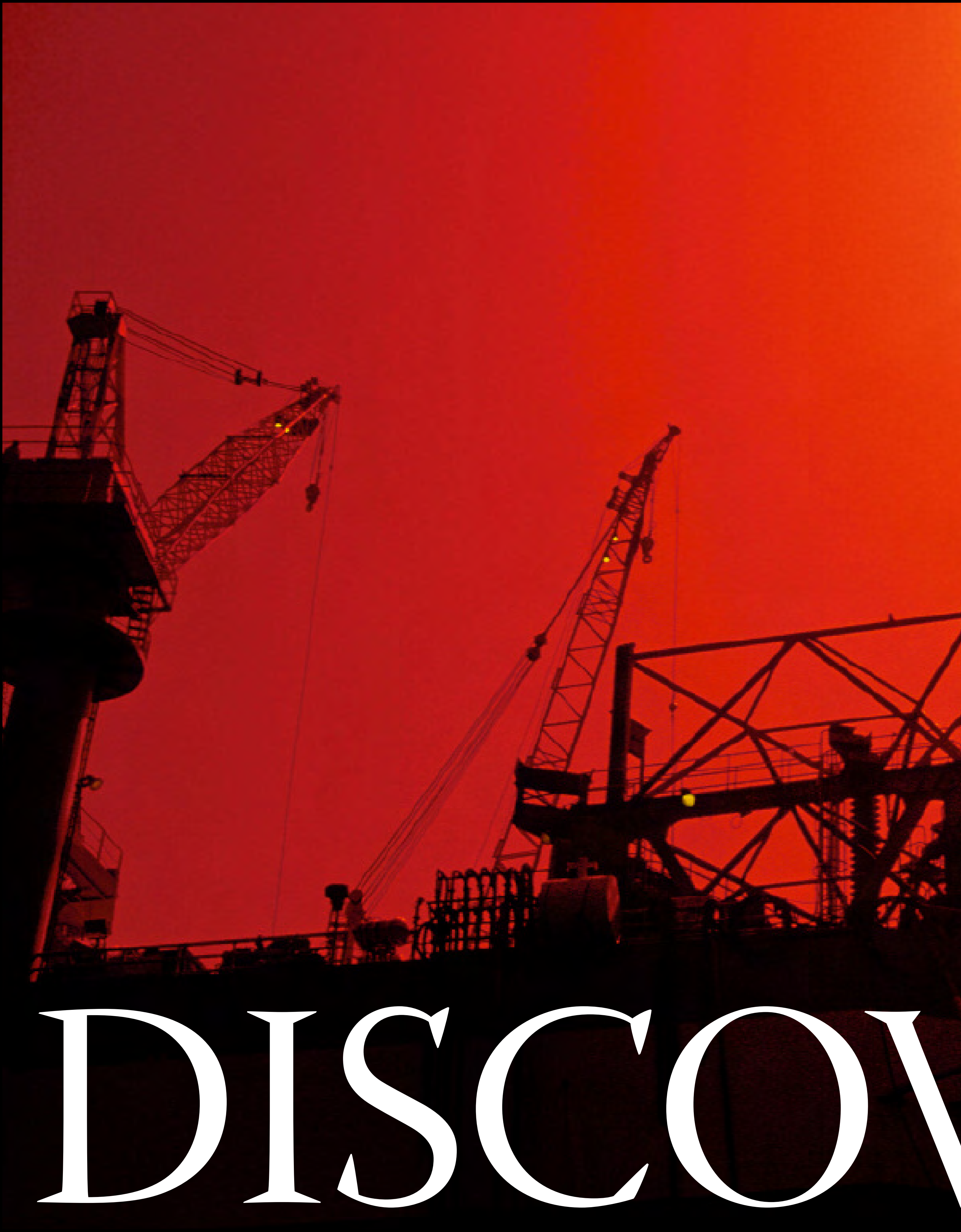
Devon was historically a North American onshore operator. Much of your exploration is now focused on offshore projects in the Gulf of Mexico and abroad. What gives you the confidence that Devon has the capabilities required to succeed?

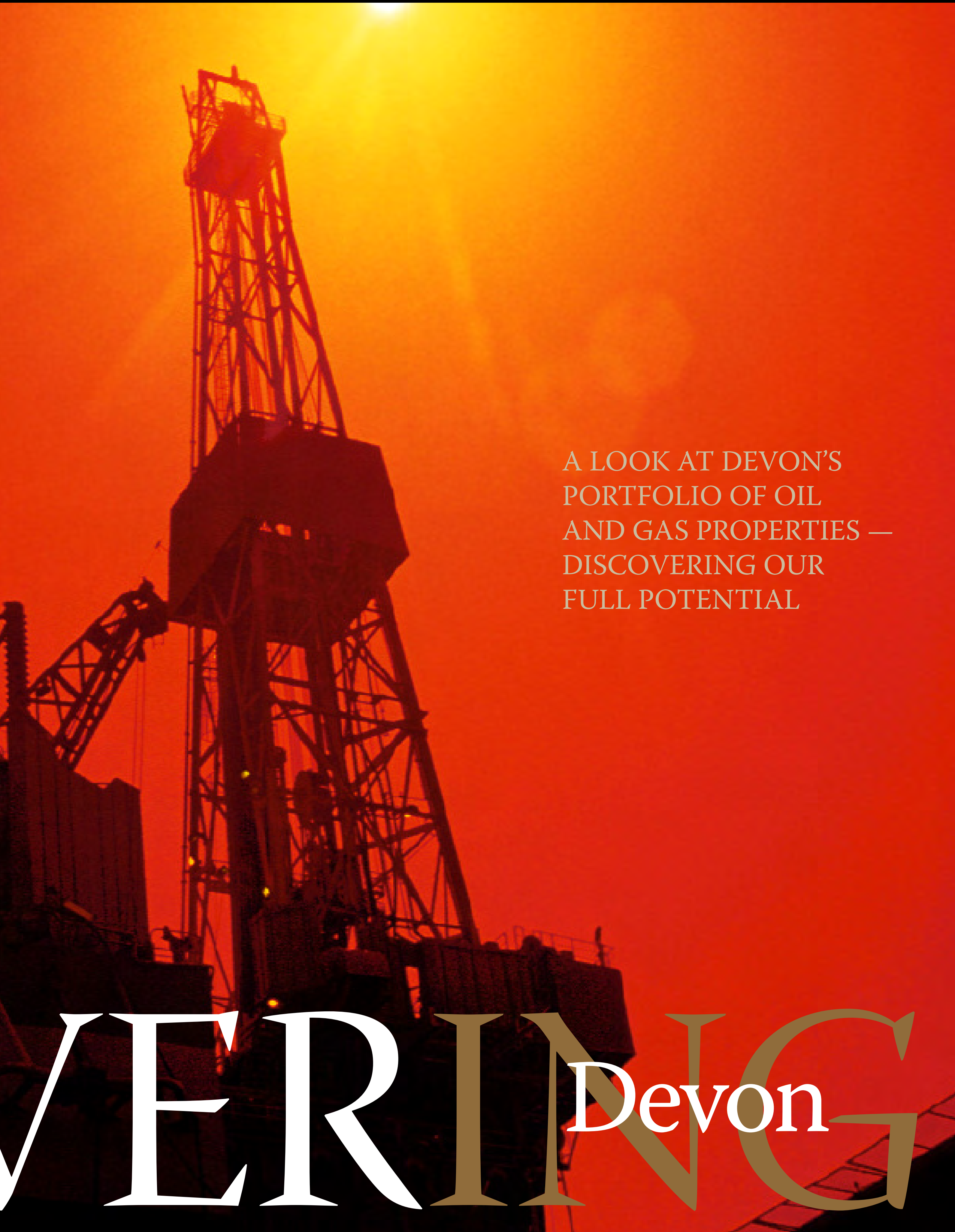
DARRYL SMETTE:

Nothing inspires confidence like success. Devon made a strategic decision in 2001 to embark on a high-impact exploration program in the Gulf of Mexico. Since that time we have dramatically increased our holdings in the deepwater Gulf, established a large prospect inventory and made three significant discoveries. We believe that this expertise translates well to West Africa and Brazil. As in the Gulf of Mexico, we have also had early success in Brazil. In late 2004, we announced an oil discovery on our BM-C-8 block offshore Brazil.

Devon did not establish this expertise overnight. Beginning with our acquisition of PennzEnergy in 1999, Devon has acquired three companies with a significant presence in the Gulf of Mexico and international arenas. From each of these companies, we have attempted to keep the best assets and the best people. As a result, Devon has assembled a good deal of institutional expertise in offshore and international operations.

We have demonstrated our operating capabilities with the success of the Devon-designed and operated Panyu project in the South China Sea and through our active role in the construction and deployment of the Red Hawk cell spar in the deepwater Gulf.


DISCOV



VERING

A LOOK AT DEVON'S PORTFOLIO OF OIL AND GAS PROPERTIES — DISCOVERING OUR FULL POTENTIAL

Devon

PORTFOLIO OF OIL AND GAS PROPERTIES —
DISCOVERING OUR FULL POTENTIAL

The acquisitions of Anderson Exploration in 2001, Mitchell Energy in 2002 and Ocean Energy in 2003, dramatically increased Devon's operational footprint. Devon quickly became one of the largest independent oil and gas producers in North America and one of the largest independent acreage holders in the deep waters of the Gulf of Mexico and West Africa. However, these transactions were not completed just to make Devon bigger. The acquisitions and subsequent related divestitures of non-core and low growth properties have made Devon better. With an improved opportunity set, Devon is now positioned with the properties, the expertise and the financial resources to deliver sustainable organic growth.

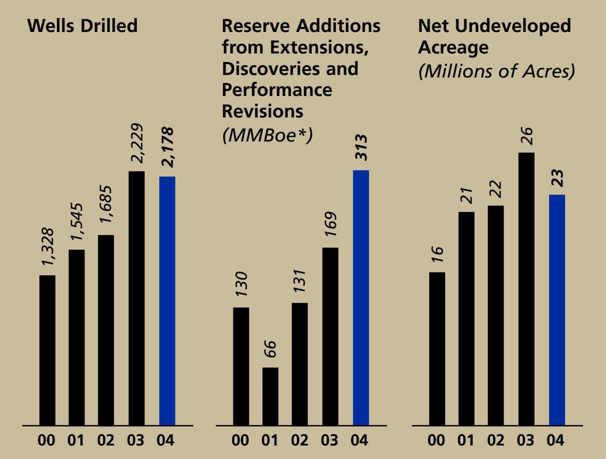
Devon's growth strategy comprises near-term and long-term elements. The near-term strategy relies upon our onshore property base in the United States and Canada to deliver repeatable, low-risk reserves and production growth. To sustain growth over the longer term, we are also investing in large-scale development projects and high-impact exploration in frontier areas in North America and abroad.

NORTH AMERICAN ONSHORE ASSETS DELIVER REPEATABLE RESULTS

At the close of 2004, almost 80% of Devon's oil and gas reserves were concentrated in the company's core producing areas located onshore in the United States and Canada. *(Please refer to Operating Statistics by Area on page 16 for this and other comparisons.)* These core onshore properties generate over 70% of Devon's current oil and gas production and are the target of roughly three quarters of our 2005 exploration and production capital budget.

In 2004, we added 281 million equivalent barrels of proved reserves from discoveries, extensions and performance revisions on our North American onshore properties. This far exceeded the 177 million equivalent barrels these properties produced in 2004 and more than replaced the 251 million equivalent barrels Devon produced company wide.

Not only do Devon's core North American onshore producing properties consistently deliver low-risk reserves and production additions, they do so economically. The 281 million equivalent barrels added in 2004 resulted from just over $2 billion of capital expenditures. These impressive results reflect the performance of Devon's core assets across our North American asset base and Devon's commitment to deliver efficient growth. A discussion of some of our most significant North American assets follows.



Devon drilled more than 2,100 oil and gas wells during 2004…

…and added over 300 million barrels from discoveries, extensions and performance revisions.

We ended 2004 with more than 20 million net undeveloped acres on which to drill in the future.

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

This jackup rig is drilling adjacent to an offshore production platform. Devon's offshore operations include the Gulf of Mexico, Brazil and West Africa.

PORTFOLIO OF OIL AND GAS PROPERTIES —

DISCOVERING OUR FULL POTENTIAL

Barnett Shale

Since Devon entered the play with our acquisition of Mitchell in January 2002, the Barnett Shale has rapidly grown to become the largest gas field in the state of Texas and has secured Devon's position as the state's largest gas producer. In 2004, we produced more than 34 million equivalent barrels from 1,900 Barnett Shale wells. During the year, we drilled about 200 new wells and added 60 million equivalent barrels of new reserves.

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 92 million equivalent barrels from the Barnett Shale. Remarkably, we have more reserves on the books today than when we started, demonstrating the sustainability of this exceptional asset.

More than 90% of our Barnett Shale wells are concentrated within a 120,000-acre area in Wise, Denton and Tarrant counties known as the "core area." Historically, almost all of the production from the Barnett was derived from this producing fairway. However, in 2002, Devon pioneered horizontal drilling in the Barnett, proving that, with this technique, the play could be economically expanded outside the core area.

Our success in the Barnett has recently attracted a host of industry competitors, but as the first mover, we established the premier position in the play. We currently produce more gas from the Barnett than all of our competitors combined. We dominate the core area and have more than 400,000 net acres outside the core. We are currently utilizing 3-D seismic and horizontal drilling to optimize the development of this dominant position. In 2005, we plan to drill more than 200 Barnett wells including about 100 horizontals outside the core area. *(Please refer to the Key Property Highlights pull-out following page 16 for more information about the Barnett Shale and other significant assets.)*

Carthage

The Carthage area in east Texas is another core holding that continues to provide significant reserves and production growth. In 2004, we drilled 92 wells in the Carthage area and added 28 million equivalent barrels of new reserves. Devon's production from this area climbed 33%, to 11 million equivalent barrels in 2004. In 2005, we plan to drill more than 100 wells in the Carthage area. Our multi-year inventory of low-risk drilling locations should yield years of additional growth.

Washakie

The Washakie field in the Rocky Mountains continues to be a source of repeatable growth for Devon. In 2004, we produced five million equivalent barrels, drilled 60 wells and added 14 million equivalent barrels of new reserves. In 2005, we plan to drill 84 wells at Washakie from a drilling inventory of some 300 locations.

Western Canadian Sedimentary Basin

With more than eight million net undeveloped acres in Canada, Devon has the largest Canadian exploration portfolio of any U.S.-based independent. This extensive property base consistently provides low-risk production and reserves growth. In 2004, our Canadian production increased by 4%, to 65 million equivalent barrels. Our 2004 reserve additions from drilling and performance revisions totaled 122 million equivalent barrels, or almost twice the year's production.

As in the United States, our 2004 Canadian reserves growth was driven by assets spanning our base of large-scale, low-risk oil and gas properties. The Deep Basin in western Alberta and eastern British Columbia is one example. Deep Basin drilling and performance improvements added 30 million equivalent barrels of proved reserves in 2004. This compares with production of 12 million equivalent barrels. From more than 480,000 net acres on which to drill, Devon expects to add reserves and production in the Deep Basin into the future.

In addition to our predominately conventional oil and gas producing areas, Devon also owns more than 140,000 net acres in the promising Alberta oil sands. After receiving final governmental approval in late 2004, Devon's 100%-owned Jackfish thermal oil sands project is now under way. We expect Jackfish to ultimately add 300 million barrels to Devon's reserves and to produce 35,000 barrels of oil per day in 2008 when fully operational. *(Please refer to the story on page 17 for more information on the exciting Jackfish project.)*

HIGH-IMPACT INVESTMENTS PROVIDE LONG-TERM OPPORTUNITY

Devon balances its low-risk, short cycle-time investments in core producing areas with large-scale development projects and high-impact exploration in frontier areas. These activities, focused on building future growth, are concentrated in the Gulf of Mexico and international arenas.

Gulf of Mexico—Deepwater

Recent successes in the deepwater Gulf of Mexico provide glimpses of the rewards that may lie ahead. These successes include new production from the development of previous discoveries, the potential of recent discoveries and the possible reward of exploratory wells yet to be drilled.

In 2004, Devon brought two deepwater Gulf of Mexico projects on production. Our 50%-owned Red Hawk gas development project came on stream in July. Red Hawk, on Garden Banks block 876, is currently producing in excess of 120 million cubic feet of gas per day. In December, our 25%-owned Magnolia project on Garden Banks block 783 began producing. Magnolia is still in the ramp-up stage, but in March it was producing about 35,000 equivalent barrels per day from two of an expected eight total producing wells.

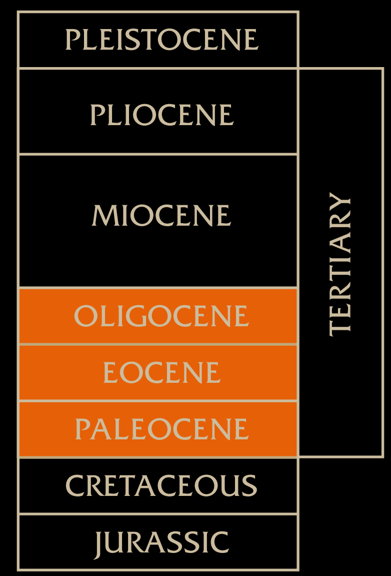
Also in 2004, Devon entered into an agreement to develop its 50%-owned Merganser gas discovery on Atwater Valley block 37. This project is part of a cooperative effort by a group of independent Gulf of Mexico operators. Under an innovative arrangement, production facilities will be designed and built to receive gas from several surrounding fields with varying ownership. This project may serve as a model for other cooperative deepwater projects in the future. Devon has committed approximately 60 million cubic feet per day of Merganser production to the project with first production expected in 2007.

In the deepwater Gulf of Mexico, most oil and gas exploration and production has historically been from Miocene age reservoirs. However, in recent years, deepwater operators have begun to test several older and deeper formations. These formations are collectively known as the "lower Tertiary." These are highlighted in the illustration *(right)*. Devon has made three potentially significant lower Tertiary discoveries in the past three years.

We drilled our first lower Tertiary discovery in 2002, on the Cascade prospect. Cascade, in which Devon has a 25% working interest, is located on Walker Ridge block 206. In 2003, we made our second lower Tertiary discovery at the St. Malo prospect on Walker Ridge block 678. Devon has a 22.5% working interest in St. Malo. This past year we drilled a successful appraisal well at St. Malo that encountered more than 400 net feet of oil pay. Also in 2004, we drilled our third lower Tertiary discovery. The 25% Devon-owned Jack well, on Walker Ridge block 759, encountered more than 350 net feet of oil pay.

In 2005, we plan to drill delineation wells on Cascade, St. Malo and Jack. In addition, we plan to carry out a production test on one of these lower Tertiary discoveries in 2005 or 2006. Should the information we gather continue to be positive, we expect to sanction development of one or more of these discoveries. At that point, we would begin recognizing reserves in anticipation of first production in 2008 or 2009.

Geologic Formations



This chart illustrates the order in which these geologic formations were deposited. The oldest and deepest formations appear at the bottom of the column. Devon has made three potentially significant discoveries in lower Tertiary sands (highlighted in orange) that lie below the Miocene.

PORTFOLIO OF OIL AND GAS PROPERTIES —

DISCOVERING OUR FULL POTENTIAL

In addition to our deepwater discoveries to date, we currently have an inventory of 23 untested lower Tertiary opportunities and 18 untested Miocene opportunities. This prospect inventory will support a robust deepwater Gulf of Mexico exploration program for years to come. However, it represents only a small portion of the 500 plus acreage blocks in which Devon has an interest in the deepwater Gulf. From this extensive acreage inventory and our ongoing participation in lease sales, we are continuously regenerating our deepwater prospect inventory.

Gulf of Mexico—Deep Shelf

Devon's high-impact exploration program in the Gulf of Mexico is not limited to the deep water. Significant resource potential also remains far beneath the shallower Gulf waters in the "deep shelf." Deep shelf wells are drilled in water less than 600 feet deep but target reservoirs below 15,000 feet. Some of these deep shelf prospects target lower Tertiary formations. Devon plans to test several deep shelf prospects in 2005 from an inventory of 28 prospects.

INTERNATIONAL OPPORTUNITIES DIVERSIFY PORTFOLIO

In addition to our high impact exploration and development projects in the Gulf of Mexico, Devon has many large-scale exploration and development projects under way in the international arena. Although properties outside North America currently account for less than 15% of Devon's company-wide production, these assets hold the potential to deliver meaningful reserves and production growth in the future. Devon's international assets include both established producing properties and high-impact exploration projects.

Zafiro Field

The Zafiro field offshore Equatorial Guinea is Devon's largest international producing property. Devon's share of production from Zafiro averaged 47,000 barrels per day in 2004, or about 50% of our total international production. Additional drilling opportunities at Zafiro should help maintain overall field production in 2005. While Devon's share of Zafiro production is expected to decline in mid-2005 under the terms of the production sharing contract, we expect Zafiro to be a profitable source of reserve additions for years to come.

11-Year Property Data [1]

	1994	1995	1996	1997	1998
Reserves (Net of royalties)					
Oil (MMBbls)	294	313	351	219	166
Gas (Bcf)	744	860	1,131	1,403	1,440
NGLs (MMBbls)	12	16	18	24	21
Oil, Gas and NGLs (MMBoe) [2]	430	472	558	477	427
10% Present Value Before Income Tax (Millions) [3]	$ 1,485	1,872	3,952	2,100	1,375
Production (Net of royalties)					
Oil (MMBbls)	27	28	30	29	20
Gas (Bcf)	101	109	116	180	189
NGLs (MMBbls)	1	1	2	3	3
Oil, Gas and NGLs (MMBoe) [2]	45	47	52	62	55
Average Prices					
Oil (Per Bbl)	$ 12.99	15.07	17.49	17.03	12.28
Gas (Per Mcf)	$ 1.69	1.44	1.82	2.04	1.78
NGLs (Per Bbl)	$ 10.17	10.62	13.78	12.61	8.08
Oil, Gas and NGLs (Per Boe) [2]	$ 11.84	12.49	14.90	14.51	11.09
Unit Production and Operating Expense (Per Boe) [2]	$ 4.83	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 16.

ACG Field

The ACG field, a five billion barrel oil resource located offshore Azerbaijan in the Caspian Sea, is expected to produce more than one million barrels per day by 2009. Under the terms of Devon's 5.6% "carried interest" in ACG, our accumulated development costs must be repaid to the carrying partners prior to Devon's full participation in the production stream. Full-scale development of ACG has awaited an oil export pipeline that is on track for completion in 2005. Although Devon's share of current production is minor, we expect it to climb to as much as 50,000 barrels per day following payout of the carry in 2007 or 2008.

South Atlantic Margin Exploration

Devon has assembled a significant inventory of high-impact exploration prospects offshore Brazil and offshore West Africa. Our exploration holdings in West Africa include offshore concessions in Angola, Gabon, Ghana, Equatorial Guinea and Nigeria. In aggregate, Devon's 11 licensed blocks represent more than five million net undeveloped acres. In Brazil, we hold five licensed blocks comprising over 700,000 net acres. The prospective targets in these areas are large enough to be meaningful to Devon as a whole—generally several hundred million barrels or more per prospect. As with most exploration wells, the chance of success on any individual prospect is relatively low. However, the likelihood of a significant discovery from Devon's extensive portfolio of prospects is much higher. During 2005, we plan to test seven of our exploratory prospects in West Africa.

Offshore Nigeria, we are currently drilling the first of two exploratory wells on Devon-operated block 256. The Tari well is testing a prospect with gross reserve potential of more than 500 million barrels. With a working interest of 37.5% in block 256, Devon's share of a discovery could be substantial. Devon also operates and intends to retain a 37.5% working interest in Nigerian block 242, which we plan to test in 2006.

We will also drill exploratory wells on blocks B and P in Equatorial Guinea and on blocks 10 and 24 offshore Angola in 2005. The deepwater of West Africa is an exploration frontier with very large resource potential. These opportunities plus Devon's extensive Gulf of Mexico prospect inventory combine to hold billions of barrels of reserve potential.

During 2004, we made an oil discovery on block BM-C-8 in Brazil. We plan additional drilling and a production test on the block in 2005, with the intent of establishing a commercial development project. Also in 2004, we acquired two additional deepwater blocks in the prolific inner trend of the Campos Basin offshore Brazil. We plan to drill wells on each of these blocks in 2006. ■

1999	2000	2001	2002	2003	2004	5-YEAR COMPOUND GROWTH RATE	10-YEAR COMPOUND GROWTH RATE
439	406	527	444	661	596	6%	7%
2,785	3,045	5,024	5,836	7,316	7,494	22%	26%
55	50	108	192	209	232	33%	35%
958	963	1,472	1,609	2,089	2,077	17%	17%
5,316	17,075	6,687	15,307	22,652	23,428	35%	32%
25	37	36	42	62	78	26%	11%
295	417	489	761	863	891	25%	24%
5	7	8	19	22	24	37%	35%
79	113	126	188	228	251	26%	19%
17.78	24.99	21.41	21.71	25.63	28.18	10%	8%
2.09	3.53	3.84	2.80	4.51	5.32	21%	12%
13.28	20.87	16.99	14.05	18.65	23.04	12%	9%
14.22	22.38	22.19	17.61	25.88	29.88	16%	10%
4.15	4.81	5.29	4.71	5.63	6.13	8%	2%

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	9,122	5,511	5,433	3,855	1,205	25,126	7,878	545	33,549
2004 Production (Net of royalties)									
Oil (MMBbls)	9	—	2	2	18	31	14	33	78
Gas (Bcf)	55	191	102	133	121	602	279	10	891
NGLs (MMBbls)	3	11	1	3	1	19	5	—	24
Oil, Gas and NGLs (MMBoe) [1]	22	43	20	27	39	151	65	35	251
Average Prices									
Oil price ($/Bbl)	$ 28.46	—	37.91	33.81	30.69	30.84	21.60	28.40	28.18
Gas price ($/Mcf)	$ 5.37	4.92	4.94	5.73	6.31	5.43	5.15	3.33	5.32
NGLs price ($/Bbl)	$ 19.20	20.69	12.49	26.86	26.78	21.47	29.23	21.12	23.04
Oil, Gas and NGLs ($/Boe) [1]	$ 28.71	27.42	29.85	33.54	34.27	30.80	28.80	27.92	29.88
Year-end Reserves (Net of royalties)									
Oil (MMBbls)	95	4	21	15	68	203	147	246	596
Gas (Bcf)	368	1,847	998	1,145	578	4,936	2,420	138	7,494
NGLs (MMBbls)	25	108	9	35	5	182	50	—	232
Oil, Gas and NGLs (MMBoe) [1]	181	420	196	241	170	1,208	600	269	2,077
Year-end Present Value of Reserves (Millions) [2]									
Before income tax	$ 2,167	3,733	2,056	2,772	2,966	13,694	5,636	4,098	23,428
After income tax	$					9,374	3,881	2,830	16,085
Year-end Leasehold (Net acres in thousands)									
Producing	327	679	526	583	519	2,634	2,383	325	5,342
Undeveloped	463	433	862	502	1,630	3,890	8,294	10,433	22,617
Wells Drilled During 2004	350	351	328	211	17	1,257	849	72	2,178
Capital Costs Incurred (Millions) [3]									
2004 Actual [4]	$ 198	446	171	330	455	1,600	960	292	2,852
2005 Forecast	$ 145-165	410-470	220-255	305-350	425-480	1,505-1,720	1,045-1,180	305-380	2,855-3,280

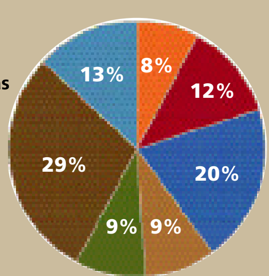
(1) Gas converted to oil at the ratio of 6Mcf:1Bbl. Natural gas liquids converted to oil at the ratio of 1Bbl:1Bbl.

(2) Estimated future revenue to be generated from the production of proved reserves, net of estimated future expenditures, 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 making relative value comparisons 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 after-tax measure in similar ways.

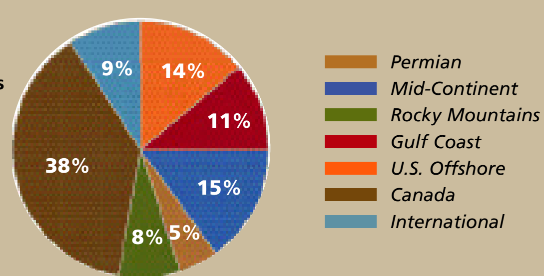
(3) 2004 actual costs incurred and 2005 forecasted capital costs include exploration and production expenditures, capitalized general and administrative costs, capitalized interest costs and asset retirement costs.

(4) 2004 actual costs incurred also include proved property acquisitions of $15 million, $9 million, $3 million and $11 million in the Permian, Rocky Mountains, U.S. Offshore and Canada, respectively.

Year-end 2004 Proved Oil and Gas Reserves by Area



2005 Exploration and Production Expenditures Budget



devon

Areas of Operation

PERMIAN

Devon's operations in the Permian Basin of west Texas and southeast New Mexico provide the company with both oil and gas production. The Permian Basin was the source of some of the earliest oil and gas discoveries in the United States. It covers about 66,000 square miles and contains hundreds of oil and gas fields. It continues to offer exploration and low-risk development opportunities from many geologic reservoirs and depths.

MID-CONTINENT

Devon's Mid-Continent operations encompass Oklahoma, the Texas panhandle and north Texas. Devon's most important Mid-Continent asset is the prolific Barnett Shale field in the Fort Worth Basin. Acquired in the 2002 acquisition of Mitchell Energy, it is the largest natural gas field in Texas and among the fastest growing onshore natural gas fields in North America. Devon's position in the Barnett includes 535,000 net acres and about 1,900 producing wells.

ROCKY MOUNTAINS

Devon's Rocky Mountain operations extend from New Mexico to Montana. Some of Devon's most significant properties lie in the gas-prone Washakie, Wind River, Big Horn and Green River basins in Wyoming, the Bear Paw field in north-central Montana and the oil-prone Uinta basin in Utah. Devon was a pioneer in coalbed natural gas, advancing one of the first and most successful projects in the world—the Northeast Blanco Unit in the San Juan Basin. Devon also holds a significant coalbed natural gas position in Wyoming's Powder River Basin.

GULF COAST

Devon's Gulf Coast operations include south and east Texas, Louisiana and Mississippi. Most reserves in the region come from long-lived oil and natural gas reservoirs found in conventional sandstone formations. Many of these have been rejuvenated in recent years through the use of 3-D seismic technology. Low-risk, infill development drilling and recompletion activities are ongoing in the Carthage and Groesbeck areas of east Texas.

GULF OF MEXICO

Devon is one of the 10 largest oil and gas producers in the Gulf of Mexico with interests in more than 700 offshore blocks. On the shelf, with water depths to 600 feet, Devon is participating in a new wave of exploratory drilling targeting formations below 15,000 feet. The deepwater Gulf (deeper than 600') is a promising frontier area believed to hold some of the largest remaining undiscovered reserves in North America. Devon is one of the largest independent deepwater Gulf leaseholders. From this inventory, the company has drilled three discoveries in the emerging lower Tertiary trend. These discoveries and more than 20 additional prospects have the potential to add significant reserves to Devon in the future.

CANADA

Devon is among the largest independent oil and gas producers in Canada. Most of the country's producing fields are located in the Western Canadian Sedimentary Basin. Devon's Canadian oil and gas production includes conventional resources, cold-flow heavy oil and thermal heavy oil. Many areas are restricted to winter-only access, which requires drilling activity to be concentrated in the coldest months. Devon also holds extensive exploratory acreage far to the north in the Mackenzie Delta and Beaufort Sea. These areas are believed to hold significant undiscovered oil and gas resources but currently lack pipeline infrastructure.

AZERBAIJAN

One of Devon's largest concentrations of proved reserves outside North America is located offshore Azerbaijan in the Caspian Sea. Devon has a 5.6% carried interest in the five billion barrel Azeri-Chirag-Gunashli (ACG) oil development project. Upon completion of the Baku-T'Bilisi-Ceyhan pipeline in 2005, Azerbaijan will become a significant supplier of crude oil to world markets. Devon's net share of production is expected to reach as much as 50,000 barrels per day in 2007 or 2008.

CHINA

In China, Devon discovered and developed the Panyu Field in the South China Sea. Two fixed platforms were installed 11 miles apart. Oil is piped from these platforms to a nearby FPSO. The Devon operated field achieved first production in 2003. Exploration potential targeting nearby satellite fields is being evaluated using the company's large 3-D seismic database.

EGYPT

In Egypt, Devon has interests in eight licensed blocks, three in the Western Desert and five operated by Devon in the Gulf of Suez. In total, these blocks cover approximately 3.9 million gross acres. Four of these concessions are currently producing.

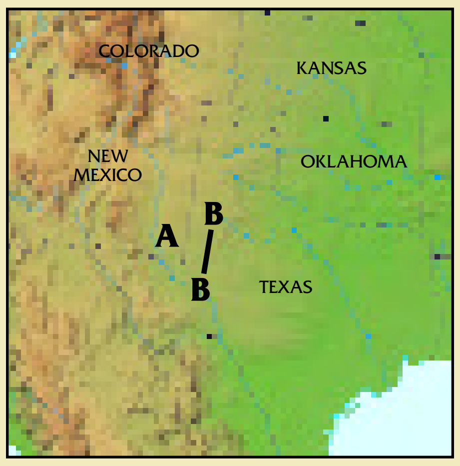
WEST AFRICA

Some of Devon's most significant international exploration and production projects lie under the waters of coastal West Africa. The company's largest international producing property is the Zafiro field located offshore Equatorial Guinea. Southern expansion of the field in 2003 pushed gross production from Zafiro to 300,000 barrels of oil per day. In 2005, Devon will drill exploratory wells in Equatorial Guinea, Angola and Nigeria.

BRAZIL

Devon holds interests in five exploration blocks offshore Brazil covering more than one million gross acres. In 2005, the company will drill follow-up wells to its 2004 discovery on block BM-C-8.

KEY PROPERTY HIGHLIGHTS



PERMIAN

A Southeast New Mexico

Profile
- 75% average working interest in 544,000 acres in southeast New Mexico.
- Key fields include Ingle Wells, Gaucho, West Red Lake, Catclaw Draw and Outland.
- Produces oil and gas from multiple formations at 1,500' to 16,500'.
- 65.8 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Drilled and completed 33 gas wells.
- Drilled and completed 61 oil wells.
- Recompleted 33 wells.

2005 Plans
- Drill 25 gas wells.
- Drill 42 oil wells.
- Recomplete 34 wells.
- Divest non-core properties.

B West Texas

Profile
- 40% average working interest in 1.1 million acres in west Texas.
- Key fields include Wasson and Anton-Irish to the north and Ozona, Keystone/Kermit and Waddell to the south.
- Produces oil and gas from multiple formations at 2,500' to 18,000'.
- 115.5 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Drilled and completed 37 gas wells.
- Drilled and completed 19 oil wells.
- Recompleted 26 wells.

2005 Plans
- Drill 17 gas wells.
- Drill 36 oil wells.
- Recomplete 53 wells.
- Divest non-core properties.

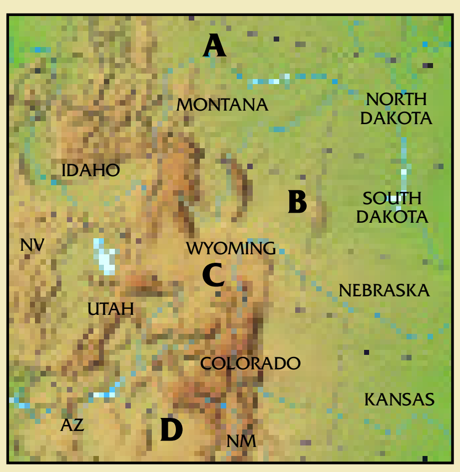
MID-CONTINENT

A Barnett Shale

Profile
- 535,000 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'.
- 323.8 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Drilled 149 wells within core area, including:
  - 100 vertical infill wells.
  - 49 horizontal wells.
- Drilled 51 wells outside core area, including:
  - 12 vertical wells.
  - 39 horizontal wells.
- Refractured 27 wells in core area.
- Acquired 3-D seismic and acreage.

2005 Plans
- Drill 125 wells within core area, including:
  - 70 vertical infill wells.
  - 55 horizontal wells.
- Drill 101 horizontal wells outside core area.
- Refracture 30 wells.
- Acquire additional 3-D seismic and acreage.



ROCKY MOUNTAINS

A Bear Paw

Profile
- 470,000 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'.
- 19.3 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Drilled and completed 39 wells.
- Performed 48-well workover program.

2005 Plans
- Drill up to 83 wells, including 1 deeper exploratory well.
- Evaluate coalbed natural gas potential.
- Continue workover program.

B Powder River Coalbed Natural Gas

Profile
- 75% average working interest in 346,000 acres in northeastern Wyoming.
- Produces coalbed natural gas from the Fort Union Coal formations at 300' to 2,000'.
- 14.7 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Drilled 155 coalbed natural gas wells.
- Connected 111 wells to gas sales.
- Recompleted 34 wells.
- Installed vacuum compression for 260 wells.
- Acquired additional interest in North Rough Draw field and expanded Juniper Draw field through acreage trades.

2005 Plans
- Drill 120 coalbed natural gas wells.
- Deepen 44 wells.
- Recomplete 10 wells.
- Install vacuum compression on 53 wells.

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'.
- 85.7 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Drilled and completed 60 wells.
- Recompleted 7 wells.
- Initiated plunger installation program to stimulate production.

2005 Plans
- Drill 84 wells.
- Recomplete 8 wells.
- Install up to 200 plungers.

D NEBU/32-9 Units

Profile
- 25% average working interest in 50,000 acres in the San Juan Basin of northwestern New Mexico.
- Coalbed natural gas development began in the late 1980s and early 1990s.
- Includes 237 coalbed natural gas wells and 207 conventional wells.
- Produces primarily coalbed natural gas from the Fruitland Coal formation at 3,000'.
- 21.7 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Drilled and completed 51 infill coalbed natural gas wells.
- Completed 11-well workover program.
- Installed 16 pumping units for water removal.
- Drilled and completed 21 conventional gas wells.
- Recompleted 2 conventional wells.

2005 Plans
- Drill 27 infill coalbed natural gas wells.
- Initiate 15-well workover program.
- Install 17 pumping units for water removal.
- Drill 33 conventional gas wells.
- Recomplete 14 conventional wells.

GULF COAST

A Carthage Area

Profile
- 85% average working interest in 176,000 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 1,370 producing wells.
- 127.2 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Drilled and completed 92 wells.
- Recompleted 80 wells.

2005 Plans
- Drill 106 wells.
- Recomplete 65 wells.
- Expand gathering system capacity at Carthage.

B Groesbeck Area

Profile
- 72% average working interest in 191,000 acres in east central Texas.
- Key fields include Personville, Nan-Su-Gail, Dew and Bald Prairie.
- Produces from the Travis Peak, Cotton Valley and Bossier formations at 6,000' to 13,000'.
- Includes 520 producing wells.
- 39.8 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Drilled and completed 49 wells.
- Recompleted 47 wells.

2005 Plans
- Drill 37 wells.
- Recomplete 10 wells.

C South Texas

Profile
- 66% average working interest in 660,000 acres.
- Key areas include Zapata, Agua Dulce/N. Brayton, Houston area and Pettus/Ray Ranch.
- Produces oil and gas from the Frio/Vicksburg, Yegua, Wilcox and Woodbine trends at 1,500' to 15,000'.
- 45.7 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Drilled and completed 70 wells.
- Recompleted 97 wells.

2005 Plans
- Drill 57 wells.
- Recomplete 41 wells.
- Divest non-core properties.

GULF OFFSHORE – SHELF

A Eugene Island 126 Area

Profile
- Includes 12 blocks located in and around Eugene Island 126.
- Working interests range from 25% to 100%.
- Located offshore Louisiana in 40' of water.
- Produces oil and gas from sands at 4,500' to 10,500'.
- 5.3 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Drilled and completed Tikal discovery at Eugene Island 142.
- Installed production facilities for Tikal discovery.
- Drilled and completed 1 development well at Eugene Island 125.
- Performed 6-well recompletion program at Eugene Island 126 area.

2005 Plans
- Commence production from Tikal discovery.
- Evaluate development potential at Eugene Island 125.
- Evaluate exploration potential at Eugene Island 108.

B West Cameron 165/291

Profile
- 100% working interest.
- Located offshore Louisiana in 50' of water.
- Produces gas from sands at 9,000' to 15,000'.
- 2.1 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Drilled and completed Star discovery well at West Cameron 165.
- Initiated drilling on follow-up well.

2005 Plans
- Complete follow-up well.
- Drill 1 additional follow-up well.
- Evaluate exploration potential on West Cameron 164 and 291.

Shelf Exploration Prospects

Profile

C BIG BEND
- Mustang Island A110.
- Located offshore Texas in 330' of water.
- Target formation: Miocene.
- Expected total depth: 19,500'.
- 50% working interest.
- Net unrisked reserve potential: 30 million barrels of oil equivalent.

D CADILLAC
- Viosca Knoll 251.
- Located offshore Louisiana in 110' of water.
- Target formation: Cotton Valley at 19,900' to 25,000'.
- 10% working interest.
- Net unrisked reserve potential: 122 million barrels of oil equivalent.

E CHOPIN
- Eugene Island 334.
- Located offshore Louisiana in 250' of water.
- Target formation: middle Pliocene sands at 11,000' to 12,500'.
- 100% working interest.
- Net unrisked reserve potential: 3 million barrels of oil equivalent.

F JOSEPH
- High Island 10L.
- Located offshore Louisiana in 30' of water.
- First lower Tertiary exploratory well in the western Gulf of Mexico shelf.
- Expected total depth: 24,000'.
- 20% working interest.

G RACER
- West Cameron 575.
- Located offshore Louisiana in 200' of water.
- Target formation: Lentic sands at 13,000' to 14,000'.
- 100% working interest.
- Net unrisked reserve potential: 4 million barrels of oil equivalent.

2004 Activity
- Initiated drilling of Big Bend prospect.
- Initiated drilling of Joseph prospect.

2005 Plans
- Finalize geophysical analysis and drilling contracts.
- Drill exploratory test wells.

GULF OFFSHORE – DEEPWATER

A Nansen/Boomvang Complex

Profile
- Includes 18 blocks in central East Breaks area.
- 50% working interest at the Nansen facility.
- 20% working interest at the Boomvang facility.
- 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 spars.
- 58.9 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Evaluated potential for additional drilling at Nansen.
- Commenced production from 3 new subsea wells at Boomvang.

2005 Plans
- Drill 1 to 4 wells at Nansen.
- Initiate 4-well recompletion program at Nansen.
- Divest interest in Boomvang complex.

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.
- 21.3 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Finished construction and installation of the tension-leg platform.
- Completed 1 well.
- Commenced production.

2005 Plans
- Complete remaining 7 wells.
- Evaluate potential for additional drilling.
- Evaluate third party tie-ins.

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.
- 8.1 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Finished construction and installation of cell spar.
- Commenced production from 2 wells at facility capacity of 120 million cubic feet per day gross.

2005 Plans
- 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'.
- Cooperative development of 6 nearby industry discoveries utilizing subsea tie-backs to a central production hub.
- 9.0 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Finalized central hub development option.
- Received project sanctioning.
- Committed 60 million cubic feet per day to Independence Hub.

2005 Plans
- Sidetrack and complete 2 wells.
- Initiate facility and subsea construction.

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.

F ST. MALO
- 22.5% working interest in Walker Ridge 678.
- Located offshore Louisiana in 6,900' of water.
- Target formation: lower Tertiary sands.
- Discovery well drilled in 2003.
- > 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.
- > 350' of net oil pay.

2004 Activity
- Drilled successful appraisal well at St. Malo.
- Drilled discovery well at Jack.
- Finalized Cascade appraisal well location with partners.

2005 Plans
- Drill appraisal well at Cascade.
- Drill second appraisal well at St. Malo.
- Drill appraisal well at Jack.

Deepwater Exploration Prospects

Profile

H CHILKOOT
- 20% working interest in Green Canyon 320.
- Located offshore Louisiana in 2,700' of water.
- Target formation: Miocene sands.
- Expected total depth: 32,000'.

I MAKALU
- 12.5% working interest in Mississippi Canyon 937.
- Located offshore Louisiana in 4,000' of water.
- Target formation: Miocene sands.
- Expected total depth: 30,400'.

J MISSION DEEP
- 50% working interest in Green Canyon 955.
- Located offshore Louisiana in 6,500' of water.
- Target formation: Miocene sands.

K STURGIS NORTH
- 25% working interest in Atwater Valley 182.
- Located offshore Louisiana in 3,700' of water.
- Drilled 2003 oil discovery at Sturgis South.
- Expected total depth: 30,000'.
- Potential drill in 2005-2006.

2004 Activity
- Initiated drilling at Makalu.

2005 Plans
- Finalize technical evaluation.
- Drill exploratory test wells.

CANADA

A Mackenzie Delta/Beaufort Sea

Profile
- 48% average working interest in 3.1 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.

2004 Activity
- Received regulatory approval for 2005 Beaufort Sea well.

2005 Plans
- Drill 1 exploratory well in the Beaufort Sea.

B Northeast British Columbia

Profile
- 73% average working interest in 2.2 million acres in northwestern Alberta and northeastern British Columbia.
- Key areas include Ring Border, Hamburg, Tooga/Peggo, Tommy Lakes and Wargen.
- Primarily winter-only drilling.
- Produces oil and gas from multiple formations at 8,000' to 10,000'.
- 77.0 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Completed 110 of 115 wells drilled, including:
  - 30 wells at Ring Border.
  - 16 wells at Wargen.
  - 15 wells at Tooga/Peggo.
- Added booster compressors at Tooga and Septimus.

2005 Plans
- Drill 104 total wells, including:
  - 29 wells at Ring Border.
  - 16 wells at Tooga/Peggo.
  - 16 wells at Wargen.
  - 14 wells at Hamburg/Chinchaga.

C Peace River Arch

Profile
- 68% average working interest in 1.2 million acres in western Alberta.
- Key areas include Dunvegan, Cecil, Eaglesham, Belloy, Pouce Coupe and Valhalla.
- Produces liquids-rich gas and light gravity oil from multiple formations at 4,500' to 8,000'.
- 93.6 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Completed 133 of 149 wells drilled, including:
  - 35 wells at Dunvegan.
  - 19 wells at Cecil.
  - 13 wells at Belloy.
  - 11 wells at Eaglesham.

2005 Plans
- Drill 111 total wells, including:
  - 42 wells at Dunvegan.
  - 14 wells at Cecil.
  - 11 wells at Belloy.
  - 10 wells at Eaglesham.

D Deep Basin

Profile
- 47% average working interest in 1.5 million acres in western Alberta and eastern British Columbia.
- Operate 76% of company production.
- Key areas include Wapiti, Elmworth, Bilbo, Leland and Pinto.
- Produces liquids-rich gas primarily from Cretaceous formations at 3,000' to 14,000'.
- 97.7 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Completed 182 of 187 wells drilled, including:
  - 47 wells at Wapiti.
  - 38 wells at Bilbo.
  - 33 wells at Elmworth.
  - 25 wells at Pinto.
- Expanded production facilities at Leland.
- Added compression at Bilbo.

2005 Plans
- Drill 157 total wells, including:
  - 50 wells at Wapiti.
  - 41 wells at Elmworth.
  - 22 wells at Bilbo.
  - 20 wells at Pinto.

E Foothills

Profile
- 52% working interest in 1.2 million acres in western Alberta and eastern British Columbia.
- Key exploratory areas include Grizzly Valley in eastern British Columbia, Narraway, Cabin Creek and Findley in west central Alberta and Bighorn and Moose in southern Alberta.
- High-impact, long-lived reserves.
- Produces gas from multiple formations at 4,000' to 15,000'.
- 84.7 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Completed 26 of 28 wells drilled, including:
  - 12 wells at Narraway.
  - 5 wells at Findley.
- Installed additional compression at Findley.

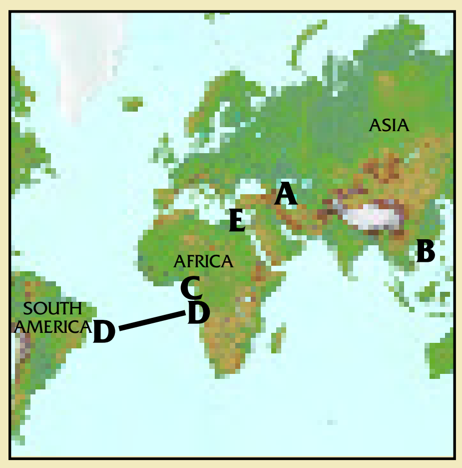
2005 Plans
- Drill 32 total wells, including:
  - 10 wells at Narraway.
  - 7 wells at Grizzly Valley.
  - 4 wells at Bighorn.
  - 3 wells at Coleman.
  - 3 wells at Findley.

F Thermal Heavy Oil

Profile
- 52% average working interest in 281,000 acres in eastern Alberta oil sands.
- Key areas include Jackfish (100% interest), Dover (92% interest) and Surmont (13% interest).
- Steam-Assisted Gravity Drainage (SAGD) is the primary recovery method.
- 300 million barrel potential at Jackfish.

2004 Activity
- Drilled all stratigraphic appraisal wells at Jackfish.
- Received final regulatory approvals for Jackfish project.

2005 Plans
- Initiate drilling 23 horizontal well pairs at Jackfish.
- Initiate Jackfish facility construction.
- Drill 40 stratigraphic wells to evaluate potential near Jackfish.
- Divest Dover and Surmont projects.



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 currently paid by partners under carried interest agreement.
- Major oil export pipeline to be completed in 2005.
- Expect up to 50,000 barrels per day net to Devon in 2007 – 2008.
- 94.6 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Drilled and completed 2 wells from the Chirag platform.
- Installed Central Azeri platform and production facilities.
- Pre-drilled 21 wells for future production from the Central, East and West Azeri platforms.

2005 Plans
- Drill 3 wells from the Chirag platform.
- Complete 12 pre-drilled wells and commence production from the Central Azeri platform.
- Install West Azeri structure.
- Continue design and construction of East Azeri, West Azeri and deepwater Gunashli facilities.
- Install compression and water injection platform in Central Azeri field.
- Export first oil through BTC Pipeline.

B China – Panyu

Profile
- 24.5% working interest in 719,000 acres in block 15/34 offshore China.
- Located in the Pearl River Mouth Basin in 300' of water.
- Produces oil from 1998 and 1999 discoveries.
- 16.1 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Drilled and completed 20 development wells.
- Drilled 2 exploratory test wells, resulting in 1 discovery.
- Ramped up production to a peak rate of 85,000 barrels per day gross.
- Initiated debottlenecking operations on the FPSO.

2005 Plans
- Drill 9 development wells.
- Drill 2 to 3 exploratory wells in satellite fields.
- Install water handling facilities on each platform.
- Continue debottlenecking efforts on FPSO.

C Equatorial Guinea – Zafiro

Profile
- 23.75% working interest in 35,900 acres in the Zafiro field in block B offshore Equatorial Guinea (E.G.).
- Field facilities include 1 fixed production platform and 2 floating production vessels in 500' to 2,500' of water.
- Contains 59 producing wells, 20 water injection wells and 1 gas injection well.
- Produces oil from a complex system of reservoir channels at 5,000' to 6,000'.
- 95.6 million barrels of oil equivalent reserves at 12/31/04.

2004 Activity
- Reached cost recovery payout.
- Drilled and completed 9 producing wells.
- Drilled and completed 8 injection wells.

2005 Plans
- Drill 8 to 10 development wells.
- Drill 1 injection well.
- Evaluate 3-D seismic data for future potential.
- Upgrade FPSO and platform facilities.

D South Atlantic Margin Exploration

Profile
- 11.6 million acres in 11 licensed blocks offshore West Africa:
  - Angola block 10; 35% interest.
  - Angola block 16; 15% interest.
  - Angola block 24; 65% interest.
  - E.G. block B; 23.75% interest.
  - E.G. block C; 24.44% interest.
  - E.G. block N; 34% interest.
  - E.G. block P; 38.4% interest.
  - Gabon Agali block; 50% interest.
  - Ghana Keta block; 90% interest.
  - Nigeria block 256; 37.5%* interest.
  - Nigeria block 242; 75% interest.
  - * Subject to government approval.
- 1.0 million acres in 5 licensed blocks offshore Brazil:
  - Block BC-2; 15% interest.
  - Block BM-BAR-3; 100% interest.
  - Block BM-C-8; 60% interest.
  - Block BM-C-30; 25% interest.
  - Block BM-C-32; 40% interest.

2004 Activity
- Completed farmout agreement with industry partner on block C in E.G.
- Drilled 1 exploratory dry hole on block P in E.G.
- Secured farmout agreements with industry partners on block 256 in Nigeria.
- Acquired block 242 in Nigeria.
- Drilled discovery well on block BM-C-8 in Brazil.
- Acquired blocks BM-C-30 and BM-C-32 in Brazil.

2005 Plans
- Drill 2 exploratory wells on block 10 in Angola.
- Drill 1 exploratory well on block 24 in Angola.
- Drill 1 exploratory well on block B in E.G.
- Acquire 2-D seismic on block N in E.G.
- Drill 1 exploratory well on block P in E.G.
- Solicit farmout on the Keta block in Ghana and Angola block 24.
- Drill 2 exploratory wells on block 256 in Nigeria.
- Complete farmout agreements with industry partners on block 242 in Nigeria.
- Acquire 3-D seismic on block 242 in Nigeria.
- Drill 3 to 5 exploratory and appraisal wells on block BM-C-8 in Brazil.
- Solicit farmout and drill 1 exploratory well on block BM-BAR-3 in Brazil.
- Acquire 3-D seismic on blocks BM-C-30 and BM-C-32 in Brazil.

E Egypt – Gulf of Suez Exploration

Profile
- 345,000 acres in 5 licensed blocks in the Gulf of Suez offshore Egypt:
  - Ras Abu Darag; 50% interest.
  - Southeast July; 50% interest.
  - East Zeit; 100% interest.
  - North Zeit Bay; 50% interest.
  - Southwest Gebel El Zeit; 43.75% interest.

2004 Activity
- Secured farmout agreements with industry partner on Ras Abu Darag, North Zeit Bay and Southeast July.
- Spud first of three-well exploration program on Ras Abu Darag.
- Drilled and completed 1 exploratory well on East Zeit and initiated drilling on second.
- Drilled 1 exploratory dry hole on Southeast July.
- Acquired 3-D seismic on Southwest Gebel El Zeit.
- Drilled 1 exploratory dry hole on Khaligue El Zeit and relinquished block.

2005 Plans
- Drill 2 exploratory wells and acquire 3-D seismic extension on Ras Abu Darag.
- Complete East Zeit exploratory well initiated in 2004.
- Drill 1 exploratory well on Southeast July.
- Drill 3 exploratory wells on North Zeit Bay.
- Drill 1 exploratory well on Southwest Gebel El Zeit.
- Finalize agreement on Devon operated Gulf of Suez South October block and Western Desert North Quaran block.

SAGD technology

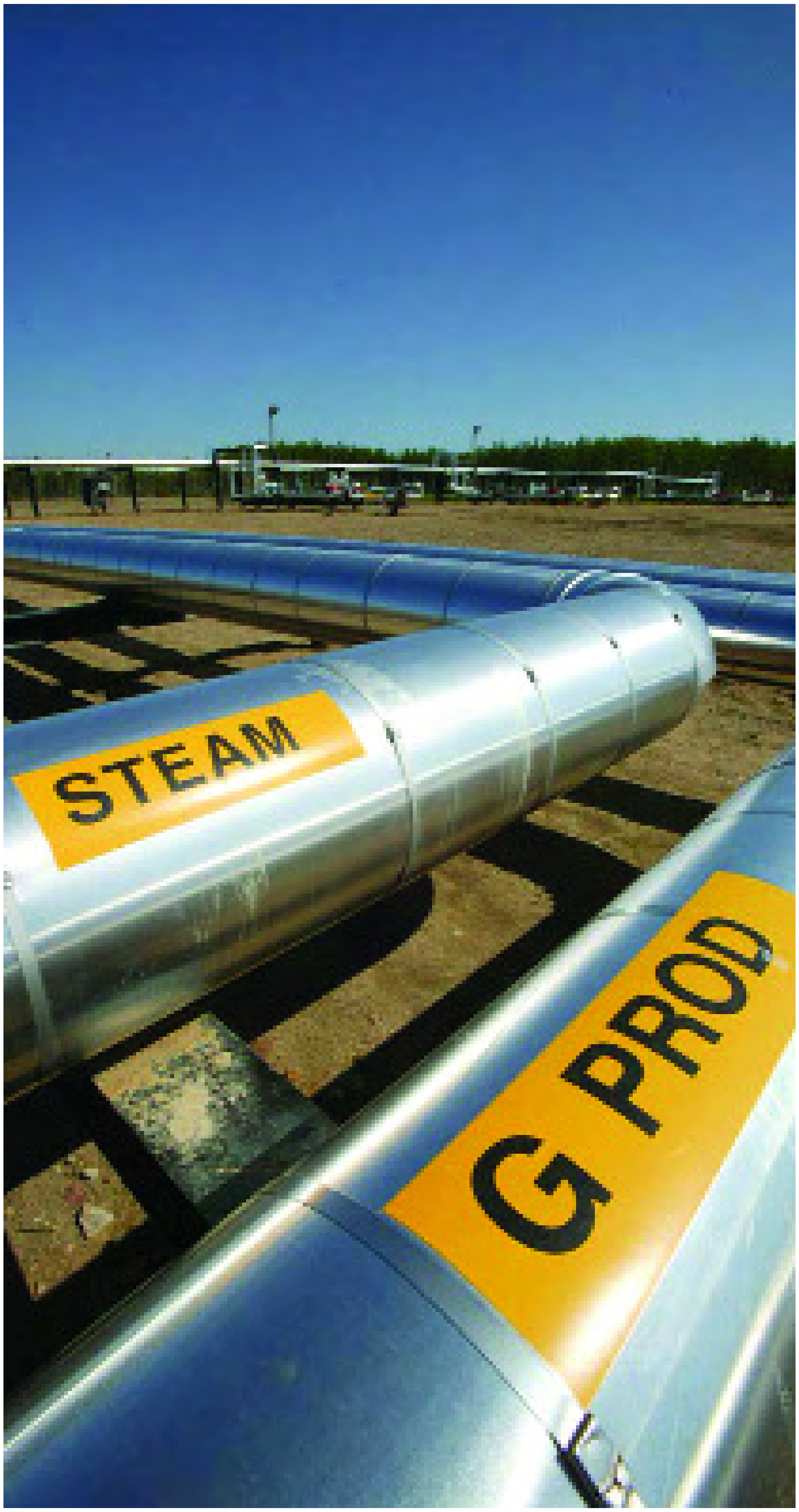


Photo courtesy of OILWEEK Magazine

Shown here are pipes carrying steam for injection and oil produced in a Devon-operated thermal heavy oil project. Our Jackfish project will utilize similar technology.

Jackfish to Tap Canadian Oil Sands

In late 2004, Devon received final government approval of its Jackfish thermal heavy oil project in the oil sands of western Canada. The Canadian oil sands are a vast oil resource with estimated reserves second only to Saudi Arabia. Devon will begin site preparation, construction and drilling at Jackfish in the spring of 2005. We plan to begin injecting steam underground in spring 2007, leading to first oil production later that year and full production of 35,000 barrels per day in 2008.

Jackfish is owned 100 percent by Devon and contains an estimated 300 million barrels of recoverable reserves. The site is located in northeastern Alberta, near the town of Conklin. The tar-like bitumen, deposited in the oil sands, cannot be extracted by conventional oil production methods. Shallow bitumen deposits are surface mined, but the deeper Jackfish project will use steam-assisted gravity drainage (SAGD) technology. The SAGD process requires drilling parallel horizontal well pairs. Each well pair includes an upper well through which steam is injected and a lower well that delivers the liquefied bitumen to the surface, pressured by the force of the steam.

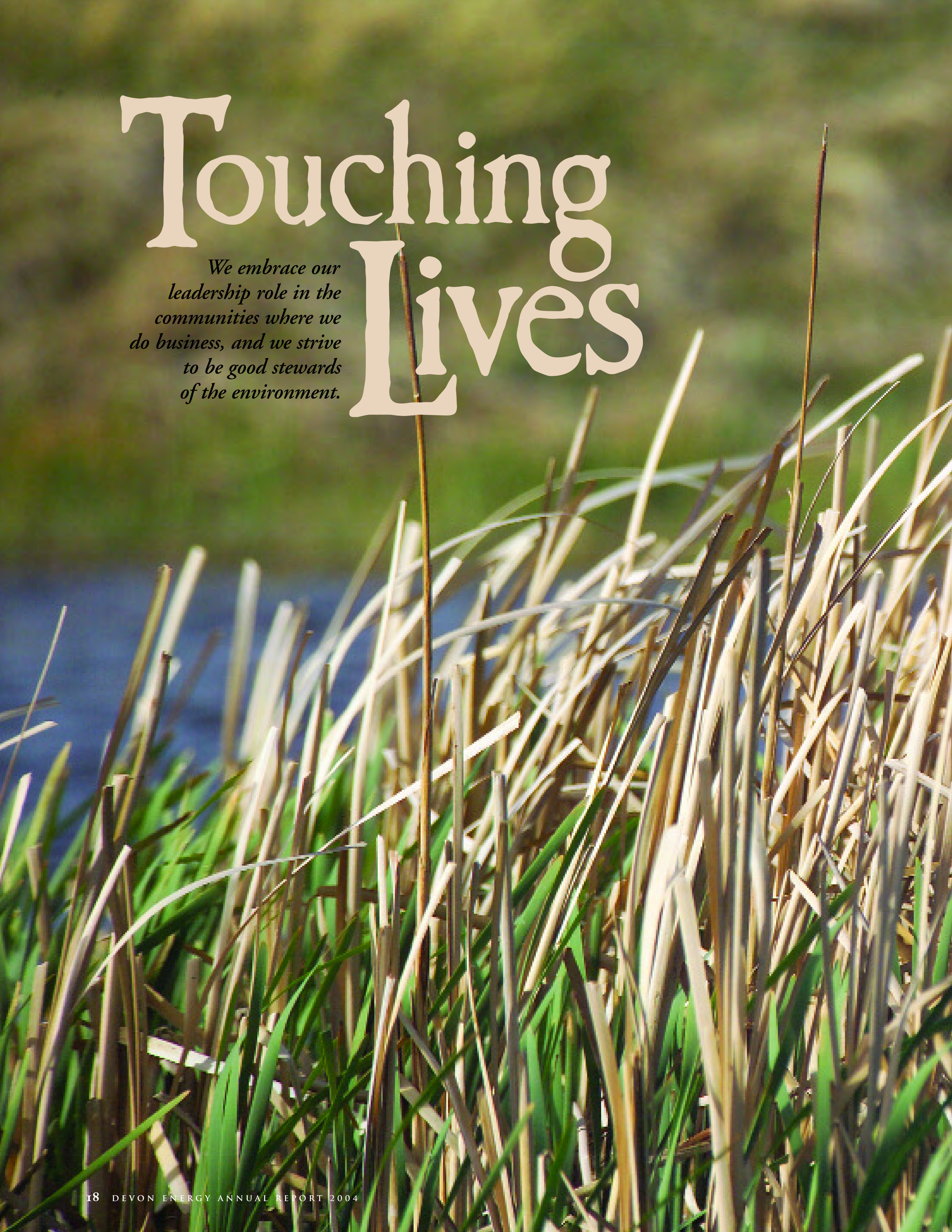
At full production, each well pair is expected to flow up to 1,000 barrels of oil per day to the surface. Unlike conventional oil projects, SAGD wells experience very little decline once production has stabilized. Jackfish is expected to produce 35,000 barrels per day for 20 years or more.

Geological and operational risks are low, as are capital costs per barrel. However, operating costs are generally higher for SAGD projects than for conventional projects. Natural gas fuels the steam generators, requiring three-quarters to one thousand cubic feet of gas for each barrel of bitumen produced.

Because of its heavy viscosity, bitumen must be diluted with a lighter product before it can be transported by pipeline. Depending upon market conditions, Devon plans to dilute the Jackfish bitumen with synthetic crude, lighter oil or condensate.

Touching Lives

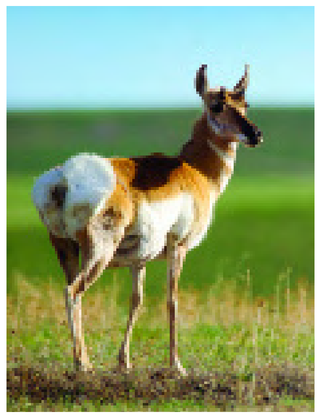
We embrace our leadership role in the communities where we do business, and we strive to be good stewards of the environment.



Touching Lives

At Devon, respect is a fundamental component of our operating culture: respect for the health and safety of our employees, respect for the environment and respect for the communities that we touch with our operations. As one of North America's largest independent oil and gas producers, we take our responsibilities seriously and constantly strive to be good stewards and good neighbors.

Our contributions to youth and education programs, health and human services agencies, community outreach and cultural projects make us a stronger company. This is because healthy communities allow businesses to grow and prosper.



We promote conservation of the natural environment and look for opportunities to preserve wildlife habitat. Our continuing efforts to reduce emissions have gained recognition from the Environmental Protection Agency (EPA). And our commitment to the welfare of our employees is illustrated by workplace safety records that consistently win accolades in the United States and Canada.

At Devon, the safety of our employees, our respect for the environment and our commitment to the communities in which we operate are essential components of a corporate value system that places people, integrity and ethics at its center.

ENVIRONMENTAL STEWARDSHIP

Meeting the world's growing demand for oil and natural gas goes beyond the engineering, geological, marketing and transportation challenges we face each day. It is not enough to find, produce and market oil and natural gas. As a conscientious steward in the areas in which we operate, we are committed to work in ways that are compatible with the natural environment.

At Devon, we are proud of our record of achievement. We set high standards and embrace our leadership role in the industry. Our stewardship initiatives are broad in scope.

Devon's water conservation efforts in Wyoming won accolades in 2004 from state and federal government agencies. Our stature as an emissions reducer is among the highest in the United States and Canada. We seek opportunities to protect or restore habitat and welcome partnerships with government and private groups to achieve habitat conservation objectives. Whether we are reducing emissions, restoring habitat or limiting the footprint our operations leave on the landscape, we believe environmental stewardship makes good business sense.

Air and Water Quality

Emissions reductions is an area where Devon has demonstrated a commitment and desire to continue to grow as an industry leader. Since 1990, we have been investing in more efficient production and transportation technologies that reduce the volume of methane released into the atmosphere.

In 2004, in the United States, those improvements captured more than five billion cubic feet of natural gas that would have been lost in the normal production and transportation process. That is enough natural gas to heat 66,000 homes for an entire year. According to the EPA, from an air quality perspective, our 2004 emission reductions are equal to planting more than 600,000 acres of trees or taking 445,000 cars off the highway for a year. Devon joined the EPA's Natural Gas STAR program in 2003. Our advocacy and commitment as a first-year partner in the voluntary emission reduction program resulted in Devon being honored as Gas STAR's 2004 "Rookie of the Year."

Our record of emissions reductions and reporting in Canada is also among the best. Devon has obtained gold reporting status through our partnership with the Voluntary Challenge and Registry initiative. Under the program, jointly sponsored by industry and government, Devon's Canadian operations reduced annual emissions by as much as 650,000 metric tons of carbon dioxide equivalents.

Devon strives to conduct its field operations with the highest regard for wildlife and their natural surroundings.

Wildlife Habitat Conservation

We look for opportunities to restore or create wildlife habitat both within and outside our operating venues. Our projects have included participation in the national Rigs to Reefs initiative in the Gulf of Mexico and our creation of a refuge for the endangered whooping crane on the Texas Gulf Coast.

In 2004, Devon donated 300 acres for a permanent wildlife conservation easement in southern Arizona's Sonoran Desert. We teamed with a private developer and the Tucson Audubon Society to initiate the project, and then established an endowment to fund its long-term maintenance. Under the restoration plan, Audubon Society staff and volunteers are restoring native wildlife habitat along a two-mile stretch of the Santa Cruz River. The effort will ensure survival of a critical migratory link for birds, deer, bears and other animals that depend on the river as they move between mountain ranges.

Devon's track record of operating in an environmentally responsible manner has been recognized by various governmental agencies. The U.S. Department of Interior's Bureau of Land Management recognized Devon's cooperation and conservation efforts in northern Wyoming's Big Horn Mountains with its 2004 Director's Four C's Award. In addition, the Wyoming Game and Fish Department honored Devon with its 2004 Industry Reclamation and Wildlife Stewardship Award for water management and habitat improvement in the state's Powder River Basin.

WORKPLACE SAFETY

Devon's operations begin and end with safety. If we cannot do it safely, we do not do it. This philosophy is illustrated by consistent recognition from government agencies and industry associations in the United States and Canada. Whether we are working in Wyoming's Powder River Basin, Canada's Foothills or the Gulf of Mexico, our safety record consistently wins recognition for excellence.

For the second year in a row, the Gas Processors Association honored Devon with its President's Award for company-wide safety. The association also cited Devon's processing plants in Lone Camp, Texas, and Beaver Creek, Wyoming, for outstanding safety records spanning 15 years without a lost-time injury.

In Canada, Devon was given the Best Safety Performers award by the Occupational Health and Safety Council. Devon was among 350 companies selected in 2004, from a pool of 110,000 companies in Alberta.

Devon's offshore operations won two District Safety Awards for Excellence in 2004 from the U.S. Department of Interior's Minerals Management Service. The agency recognized Devon for its record of safety as well as its environmental and regulatory stewardship.

COMMUNITY INVOLVEMENT

Devon is a significant economic force in many of our operating regions, and as such, we welcome the opportunity to contribute to our communities. Volunteerism, funding and support for local schools, agencies and projects are not auxiliary functions for our company. Community involvement is a core value at Devon. We understand that it is our responsibility as a good corporate citizen to enhance the quality of life for our employees, our families and our neighbors.

Devon's spirit of outreach is broad and takes many forms. Support for charitable agencies and community projects through the United Way in the United States and Canada is a fundamental part of our stewardship philosophy. In 2004, Devon and its employees pledged nearly $1.5 million to United Way campaigns in Oklahoma City, Houston, Calgary and other communities where Devon has operations.

In rural communities where Devon operates, we support local law enforcement and crime prevention programs. We also support emergency response agencies and education in these communities.

More than 200 employees at Devon's headquarters contribute their time to a weekly tutoring program for inner-city grade-school children in Oklahoma City. Our partnership with Mark Twain Elementary School has given us an opportunity to make a difference in the lives of students who face many disadvantages. In only the second year of our partnership, Devon employees have made a measurable contribution. Aided by the one-on-one tutoring that students receive, the school has reported an increase in reading and mathematics proficiency scores. The Volunteer Center of Central Oklahoma recognized Devon's role at Mark Twain by honoring the company in 2004 with its Corporate Volunteer Group of the Year award.

Devon has provided significant financial support to higher education as well. The company pledged $1 million in 2004 to Oklahoma City University's Clara Luper Scholarship Program for students from inner-city high schools. Also in 2004, Devon pledged $10 million to the University of Oklahoma. This gift will fund construction of a research and teaching facility for the University's College of Engineering.

Our commitment to youth and education extends beyond our corporate headquarters in Oklahoma City. In Houston, Devon employees teach underprivileged middle and high school students about personal finance, business economics and success skills.

Students at Oklahoma City's Mark Twain Elementary School are tutored by more than 200 Devon volunteers.

Devon team members Letty Hernandez and Javier Saavedra prepare for the 178-mile MS 150 Bike Ride in Houston. The two-day bike ride raises funds to support the National MS Society's fight against multiple sclerosis.

Touching Lives

Devon also works with an inner-city elementary school under Houston's Communities in Schools program. Volunteers speak during the school's College Day, participate in the Chess Club, sponsor holiday parties and serve as mentors and role models for at-risk students.

In Canada, we express our support for education in a variety of ways. Our efforts include water stewardship programs for young people, advanced training for emergency medical technicians and vocational instruction in aboriginal communities.

Three years ago, Devon became the first corporate sponsor of Trout Unlimited's Yellow Fish Road Program. This program raises awareness of water conservation and management issues through projects in schools and youth organizations. Since 1991, the program has given more than 60,000 young people first-hand experience protecting water quality by promoting conservation practices.

Devon also supports mobile education programs for rural residents with limited access to learning opportunities. Devon's support for the STARS Human Patient Simulator Mobile Education Program recognizes the importance of education and community health. The program helps medical personnel in rural communities sharpen their emergency medical skills through hands-on training with a simulated human patient.

Devon is also a sponsor of the Northern Alberta Institute of Technology Trades program for adult students from aboriginal communities. The project provides students with 21 weeks of academic upgrading and vocational instruction needed to secure apprenticeships and careers in a variety of trades.

Our commitment to youth and education is not confined within the borders of North America. In Nigeria, we invest $1 million annually for programs that send Nigerian students to universities within their country as well as the United States and Europe. Students study petroleum engineering, geology, geophysics and other fields needed to sustain the country's growing petroleum industry.

In Cote d'Ivoire, Devon provides funding and employee volunteer time at the Bingerville Orphanage, home to more than 200 boys. We also support projects for youth in Brazil and Egypt.

We are engaged in our communities around the world because it is a social responsibility we embrace. Our performance as a corporate citizen demonstrates who we are as a company.

The Devon-supported Bingerville Orphanage is home to more than 200 boys in Cote d'Ivoire.

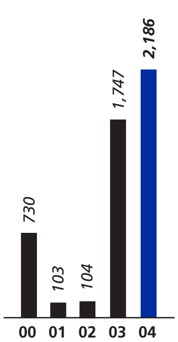
One of the children peeks from behind a toy distributed during a recent visit to the orphanage.

Financials

FEATURES

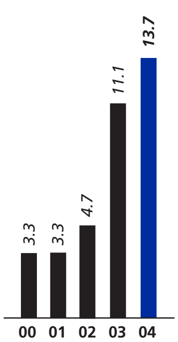
Devon transferred its common stock listing to the New York Stock Exchange in 2004.

Net Earnings
($ Millions)



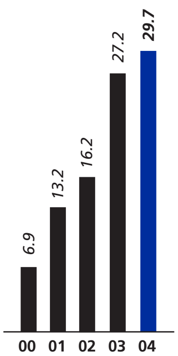
Devon earned a record $2.2 billion in 2004…

Stockholders' Equity
($ Billions)



…increasing stockholders' equity 23% to $13.7 billion…

Total Assets
($ Billions)



...and driving total assets to a record $29.7 billion.

Selected 11-Year Financial Data [1]

		1994	1995	1996	1997
OPERATING RESULTS *(In millions, except per share data)*					
Revenues *(Net of royalties)*:					
Oil sales	$	351	419	529	497
Gas sales		171	157	211	367
NGL sales		13	15	29	36
Marketing and midstream revenues		–	–	–	10
Other income		14	35	36	42
Total revenues		549	626	805	952
Production and operating expenses		218	222	271	288
Marketing and midstream costs and expenses		–	–	–	4
Depreciation, depletion and amortization of property and equipment		149	160	175	268
Accretion of asset retirement obligation		–	–	–	–
Amortization of goodwill (2)		–	–	–	–
General and administrative expenses		45	43	57	56
Expenses related to mergers		7	–	–	–
Interest expense (3)		29	39	59	51
Dividends on subsidiary's preferred stock		–	–	–	–
Effects of changes in foreign currency exchange rates		–	–	–	6
Change in fair value of financial instruments		–	–	–	–
Reduction of carrying value of oil and gas properties		22	97	–	633
Impairment of ChevronTexaco common stock		–	–	–	–
Income tax expense (benefit)		25	19	106	(128)
Total expenses		495	580	668	1,178
Net earnings (loss) before minority interest, cumulative effect of change in accounting principle and discontinued operations (4)		54	46	137	(226)
Net earnings (loss)		54	55	151	(218)
Preferred stock dividends		11	15	47	12
Net earnings (loss) to common stockholders	$	43	40	104	(230)
Net earnings (loss) per common share:					
Basic	$	0.42	0.38	0.98	(1.67)
Diluted	$	0.42	0.38	0.96	(1.67)
Weighted average shares outstanding:					
Basic		102	105	105	137
Diluted		108	105	111	151
BALANCE SHEET DATA *(In millions)*					
Total assets	$	1,475	1,639	2,242	1,965
Debentures exchangeable into shares of ChevronTexaco Corporation common stock (5)	$	–	–	–	–
Other long-term debt (6)	$	457	565	511	576
Deferred income taxes	$	30	48	136	50
Stockholders' equity	$	688	739	1,160	1,006
Common shares outstanding		104	105	126	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 ChevronTexaco Corporation common stock. These shares have been deposited with an exchange agent for possible exchange for $760 million principal amount of exchangeable debentures. The ChevronTexaco 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.
NM Not a meaningful number.

1998	1999	2000	2001	2002	2003	2004	5-YEAR COMPOUND GROWTH RATE	10-YEAR COMPOUND GROWTH RATE
236	436	906	784	909	1,588	2,202	38%	20%
335	616	1,474	1,878	2,133	3,897	4,732	50%	39%
25	68	154	131	275	407	554	52%	46%
8	20	53	71	999	1,460	1,701	143%	NM
22	10	40	69	34	37	103	59%	22%
626	1,150	2,627	2,933	4,350	7,389	9,292	52%	33%
231	328	544	666	886	1,282	1,535	36%	22%
3	10	28	47	808	1,174	1,339	166%	NM
212	379	662	831	1,211	1,793	2,290	43%	31%
–	–	–	–	–	36	44	NM	NM
–	16	41	34	–	–	–	NM	NM
48	83	96	114	219	307	277	27%	20%
13	17	60	1	–	7	–	NM	NM
53	122	155	220	533	502	475	31%	32%
–	–	–	–	–	2	–	NM	NM
16	(13)	3	11	(1)	(69)	(23)	12%	NM
–	–	–	2	(28)	(1)	62	NM	NM
354	476	–	979	651	111	–	NM	NM
–	–	–	–	205	–	–	NM	NM
(103)	(75)	377	5	(193)	514	1,107	NM	46%
827	1,343	1,966	2,910	4,291	5,658	7,106	40%	31%
(201)	(193)	661	23	59	1,731	2,186	NM	45%
(236)	(154)	730	103	104	1,747	2,186	NM	45%
-	4	10	10	10	10	10	22%	(1%)
(236)	(158)	720	93	94	1,737	2,176	NM	48%
(1.66)	(0.84)	2.83	0.37	0.31	4.16	4.51	NM	27%
(1.66)	(0.84)	2.75	0.36	0.30	4.04	4.38	NM	26%
142	187	255	255	309	417	482	21%	17%
154	199	263	259	313	433	499	20%	17%
1,931	6,096	6,860	13,184	16,225	27,162	29,736	37%	35%
–	760	760	649	662	677	692	(2%)	NM
885	1,656	1,289	5,940	6,900	7,903	6,339	31%	30%
15	313	634	2,149	2,627	4,370	4,800	73%	NM
750	2,521	3,277	3,259	4,653	11,056	13,674	40%	35%
142	253	257	252	314	472	484	14%	17%

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

OVERVIEW

According to most key financial and operating measures, 2004 was the best year in Devon's history. We delivered record production, earnings, earnings per share and cash flow from operations. Additionally, our drilling program was very successful.

We produced 251 million Boe in 2004, representing a 10% increase over our 2003 production of 228 million Boe. The largest contributor to this growth was the merger with Ocean in April 2003. With four additional months of production in 2004, the Ocean merger generated 21 million Boe of the year-over-year growth. Additionally, production in China began in the fourth quarter of 2003 and contributed seven million Boe of 2004 growth. These increases were partially offset by a decline in offshore Gulf of Mexico production due to the effects of Hurricane Ivan and natural production declines on certain other properties.

In 2004, we also delivered the highest net earnings, $2.2 billion, and earnings per diluted share, $4.38, in our 16 years as a public company. With an increase in production and increases in average realized commodity prices, Devon's oil, gas and NGL revenues climbed 27% to almost $7.5 billion. Also contributing to the growth in earnings, our marketing and midstream margin grew 26% to $362 million in 2004 primarily due to higher realized prices for natural gas and NGLs.

Record production and revenues were partially offset by higher operating expenses in 2004. The primary factors driving the increases in expenses were increased operations due to the Ocean merger, increased well workover activity, the weakening of the U.S. dollar versus the Canadian dollar and increased production taxes. The higher production taxes tracked our increase in commodity revenues. Although most expenses increased, general and administrative expenses decreased 10% as a result of the realization of overhead and personnel efficiencies following the Ocean merger.

In addition to generating record earnings in 2004, Devon also delivered record cash flow from operations. At $4.8 billion, our 2004 cash flow from operations represents a 28% increase over 2003. This all-time high amount was used to fund a $3.1 billion capital expenditure program, $973 million of debt repayments, $189 million of common stock repurchases and $107 million of dividend payments. At December 31, 2004, we had $2.1 billion of cash and short-term investments. This amount is adequate to cover debt maturities through 2007.

Furthermore, on September 27, 2004, Devon announced two key initiatives aimed at creating additional value for its stockholders. First, we announced a property divestiture program. The sales of non-core properties located in Canada, the onshore U.S. and in the Gulf of Mexico are expected to generate $1.0 to $1.5 billion in after-tax proceeds. Closings are expected in the first half of 2005. Second, we announced a stock repurchase program. With cash flow from operations and proceeds from the planned sales of oil and gas properties, we intend to repurchase up to 50 million shares of our common stock. Through February 28, 2005, we had repurchased 12.5 million shares at a total cost of $501 million.

In 2004, we declared a two-for-one stock split and moved our stock listing to the New York Stock Exchange. At its March 2005 meeting, Devon's board of directors approved the increase of the quarterly cash dividends from $0.05 per share to $0.075 per share. The increase is effective March 31, 2005.

Oil, gas and NGL prices and, therefore, oil, gas and NGL revenues are influenced by many factors outside of our control. Consequently, Devon's management has focused its efforts on increasing oil and gas reserves and production and controlling costs. Devon's future earnings and cash flows are dependent on our ability to continue to contain our overall cost structure at a level that will allow for profitable production. As a result, Devon has established a foundation of core assets in North America that can consistently deliver cost-efficient drill-bit growth and provide a strong source of free cash flow. We balance this foundation of core assets with measured investment in high-impact projects in the deepwater Gulf of Mexico and international arenas.

During 2004, Devon drilled 274 exploration wells and over 1,900 development wells, and we incurred $2.9 billion in costs related to oil and gas property acquisition, exploration and development activities. With an overall drilling success rate of 96%, reserves grew 268 million Boe from discoveries and extensions. Another 45 million Boe of reserves were added to Devon's reserve base from performance revisions. These 2004 drilling results are evidence of our success in lowering the costs of adding proved reserves.

At December 31, 2004, our proved reserves totaled 2.1 billion Boe. Although reserve additions due to discoveries, extensions and performance revisions outpaced 2004 production, reserves at December 31, 2004 were relatively flat compared to December 31, 2003. This resulted from negative price revisions which reduced reserves by 76 million Boe.

To estimate reserves, accounting rules dictate that prices in effect as of the last day of the period are held constant indefinitely. As a result, two primary factors caused the negative price revisions at December 31, 2004. First, Devon's reserves under certain international production sharing contracts are based in part on the amount of revenue needed to recover our costs. Therefore, as prices increase, as was the case for Brent prices at December 31, 2004 compared to December 31, 2003, our international reserves associated with production sharing contracts decrease. Second, heavy oil differentials in Canada widened to over 54% of the NYMEX price at December 31, 2004 compared to a historical average of approximately 30%. Both circumstances were the primary causes of the 2004 negative price revisions.

While Devon has consistently increased production over time, volatility in oil, gas and NGL prices has resulted in considerable variability in earnings and cash flows. Prices for oil, gas and NGLs are determined primarily by market conditions. Market conditions for these products have been, and will continue to be, influenced by regional and worldwide economic activity, weather and other factors that are beyond our control. Market conditions, among other factors, will continue to impact Devon's future earnings and cash flows.

Like all oil and gas exploration and production companies, Devon faces the challenge of natural production decline. As virgin reservoir pressures are depleted, oil and natural gas production from a given well naturally decreases. Thus, an oil and gas exploration and production company depletes part of its asset base with each unit of oil or gas it produces. Historically, we have been able to overcome this natural decline by adding, through drilling and acquisitions, more reserves than we produce. Devon's future growth will depend on our ability to continue to add reserves in excess of production.

In summary, 2004 was a successful year for Devon and its stockholders, and the outlook for 2005 is promising as well. Devon's base of core North American resources continues to deliver strong production growth, high margins and attractive returns. Our exploration weighted activities in the Gulf of Mexico and in our international division will expose stockholders to meaningful value creation opportunities. Devon's financial position provides the flexibility to simultaneously invest in exploration and development projects, retire debt and repurchase stock and, as was recently approved, increase cash dividends in 2005.

RESULTS OF OPERATIONS

Revenues

Changes in oil, gas and NGL production, prices and revenues from 2002 to 2004 are shown in the following tables. (Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.)

	TOTAL YEAR ENDED DECEMBER 31,				
	2004	2004 vs 2003 (2)	2003	2003 vs 2002 (2)	2002
PRODUCTION					
Oil (MMBbls)	78	+26%	62	+48%	42
Gas (Bcf)	891	+3%	863	+13%	761
NGLs (MMBbls)	24	+10%	22	+11%	19
Oil, gas and NGLs (MMBoe) (1)	251	+10%	228	+21%	188
AVERAGE PRICES					
Oil (per Bbl)	$ 28.18	+10%	25.63	+18%	21.71
Gas (per Mcf)	$ 5.32	+18%	4.51	+61%	2.80
NGLs (per Bbl)	$ 23.04	+24%	18.65	+33%	14.05
Oil, gas and NGLs (per Boe) (1)	$ 29.88	+15%	25.88	+47%	17.61
REVENUES ($ in millions)					
Oil	$ 2,202	+39%	1,588	+75%	909
Gas	$ 4,732	+21%	3,897	+83%	2,133
NGLs	$ 554	+36%	407	+48%	275
Oil, gas and NGLs	$ 7,488	+27%	5,892	+78%	3,317

		DOMESTIC YEAR ENDED DECEMBER 31,				
		2004	2004 vs 2003 (2)	2003	2003 vs 2002 (2)	2002
PRODUCTION						
Oil (MMBbls)		31	+2%	31	+31%	24
Gas (Bcf)		602	+2%	589	+22%	482
NGLs (MMBbls)		19	+13%	17	+16%	14
Oil, gas and NGLs (MMBoe) (1)		151	+3%	146	+23%	118
AVERAGE PRICES						
Oil (per Bbl)	$	30.84	+12%	27.64	+26%	21.99
Gas (per Mcf)	$	5.43	+21%	4.50	+55%	2.91
NGLs (per Bbl)	$	21.47	+24%	17.31	+29%	13.37
Oil, gas and NGLs (per Boe) (1)	$	30.80	+18%	26.02	+46%	17.87
REVENUES ($ in millions)						
Oil	$	976	+13%	861	+64%	524
Gas	$	3,261	+23%	2,652	+89%	1,403
NGLs	$	405	+40%	289	+51%	192
Oil, gas and NGLs	$	4,642	+22%	3,802	+79%	2,119

		CANADA YEAR ENDED DECEMBER 31,				
		2004	2004 vs 2003 (2)	2003	2003 vs 2002 (2)	2002
PRODUCTION						
Oil (MMBbls)		14	+3%	14	-14%	16
Gas (Bcf)		279	+4%	267	-4%	279
NGLs (MMBbls)		5	-1%	5	-5%	5
Oil, gas and NGLs (MMBoe) (1)		65	+4%	63	-7%	68
AVERAGE PRICES						
Oil (per Bbl)	$	21.60	-8%	23.54	+12%	21.00
Gas (per Mcf)	$	5.15	+13%	4.57	+74%	2.62
NGLs (per Bbl)	$	29.23	+27%	23.08	+45%	15.93
Oil, gas and NGLs (per Boe) (1)	$	28.80	+10%	26.25	+55%	16.96
REVENUES ($ in millions)						
Oil	$	299	-6%	318	-4%	331
Gas	$	1,437	+18%	1,222	+67%	730
NGLs	$	143	+25%	114	+37%	83
Oil, gas and NGLs	$	1,879	+14%	1,654	+45%	1,144

		INTERNATIONAL YEAR ENDED DECEMBER 31,				
		2004	2004 vs 2003 (2)	2003	2003 vs 2002 (2)	2002
PRODUCTION						
Oil (MMBbls)		33	+88%	17	+662%	2
Gas (Bcf)		10	+52%	7	N/M	—
NGLs (MMBbls)		—	N/M	—	N/M	—
Oil, gas and NGLs (MMBoe) (1)		35	+86%	19	+719%	2
AVERAGE PRICES						
Oil (per Bbl)	$	28.40	+20%	23.64	+0%	23.70
Gas (per Mcf)	$	3.33	-4%	3.47	N/M	—
NGLs (per Bbl)	$	21.12	-2%	21.45	N/M	—
Oil, gas and NGLs (per Boe) (1)	$	27.92	+19%	23.45	-1%	23.70
REVENUES ($ in millions)						
Oil	$	927	+126%	409	+660%	54
Gas	$	34	+46%	23	N/M	—
NGLs	$	6	+68%	4	N/M	—
Oil, gas and NGLs	$	967	+122%	436	+710%	54

(1) Gas volumes are converted to Boe or MMBoe at the rate of six Mcf of gas per barrel of oil, based upon the approximate relative energy content of natural gas and oil, which rate is not necessarily indicative of the relationship of oil and gas prices. NGL volumes are converted to Boe on a one-to-one basis with oil. The respective prices of oil, gas and NGLs are affected by market and other factors in addition to relative energy content.

(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 meaningful.

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

		WITH HEDGES			WITHOUT HEDGES		
		2004	2003	2002	2004	2003	2002
Oil (per Bbl)	$	28.18	25.63	21.71	35.99	27.67	22.63
Gas (per Mcf)	$	5.32	4.51	2.80	5.39	4.79	2.70
NGLs (per Bbl)	$	23.04	18.65	14.05	23.04	18.65	14.05
Oil, gas and NGLs (per Boe)	$	29.88	25.88	17.61	32.60	27.48	17.36

Oil Revenues *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 Devon's domestic properties. Oil revenues increased $199 million due to a $2.55 increase in the average realized price of oil.

2003 vs. 2002 Oil revenues increased $679 million in 2003. An increase in 2003 production of 20 million barrels caused oil revenues to increase by $436 million. The April 2003 Ocean merger accounted for 25 million barrels of increased production, partially offset by production lost from the 2002 property divestitures of 5 million barrels. Oil revenues increased $243 million due to a $3.92 increase in the average price of oil.

Gas Revenues *2004 vs. 2003* Gas revenues increased $835 million in 2004. A $0.81 per Mcf increase in the average 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 Devon's domestic properties as a result of natural declines and the effects of Hurricane Ivan.

2003 vs. 2002 Gas revenues increased $1.8 billion in 2003. A $1.71 per Mcf increase in the average gas price caused revenues to increase by $1.5 billion. An increase in 2003 production of 102 Bcf caused gas revenues to increase by $287 million. The April 2003 Ocean merger and January 2002 Mitchell merger accounted for 113 Bcf and 11 Bcf of increased production, respectively, partially offset by production lost from the 2002 property divestitures of 36 Bcf. The remaining production increase was primarily related to new drilling and development in the Barnett Shale properties.

NGL Revenues *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.

2003 vs. 2002 NGL revenues increased $132 million in 2003. A $4.60 per barrel increase in average NGL prices caused revenues to increase by $100 million. An increase in 2003 production of 3 million barrels caused revenues to increase $32 million. The April 2003 Ocean merger and January 2002 Mitchell merger each accounted for 1 million barrels of increased production, partially offset by production lost from the 2002 property divestitures of 1 million barrels. The remaining production increase was primarily related to new drilling and development in the Barnett Shale properties.

Marketing and Midstream Revenues *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.

2003 vs. 2002 Marketing and midstream revenues increased $461 million in 2003. Of this increase, approximately $439 million was the result of higher overall market prices for natural gas and NGLs. Additionally, revenues increased $22 million due to higher third-party natural gas and NGL throughput volumes. The increase in volumes was primarily related to new drilling and development in the Barnett Shale properties and an additional 24 days of production in 2003 due to the timing of the January 2002 Mitchell merger, partially offset by volumes lost as a result of processing plant dispositions.

Operating Costs and Expenses

The details of the changes in operating costs and expenses between 2002 and 2004 are shown in the table below.

		YEAR ENDED DECEMBER 31,			
	2004	2004 vs 2003 (2)	2003	2003 vs 2002 (2)	2002
OPERATING COSTS AND EXPENSES ($ in millions):					
Production and operating expenses:					
Lease operating expenses	$ 1,280	+19%	1,078	+39%	775
Production taxes	255	+25%	204	+84%	111
Total production and operating expenses	1,535	+19%	1,282	+45%	886
Depreciation, depletion and amortization of oil and gas properties	2,141	+28%	1,668	+51%	1,106
Accretion of asset retirement obligation	44	+21%	36	N/M	—
Subtotal	3,720	+25%	2,986	+50%	1,992
Marketing and midstream operating costs and expenses	1,339	+14%	1,174	+45%	808
Depreciation and amortization of non-oil and gas properties	149	+19%	125	+19%	105
General and administrative expenses	277	-10%	307	+40%	219
Expenses related to mergers	—	-100%	7	N/M	—
Reduction of carrying value of oil and gas properties	—	-100%	111	-83%	651
Total	$ 5,485	+16%	4,710	+25%	3,775
OPERATING COSTS AND EXPENSES PER BOE:					
Production and operating expenses:					
Lease operating expenses	$ 5.11	+8%	4.73	+15%	4.12
Production taxes	1.02	+13%	0.90	+53%	0.59
Total production and operating expenses	6.13	+9%	5.63	+20%	4.71
Depreciation, depletion and amortization of oil and gas properties	8.54	+17%	7.33	+25%	5.88
Accretion of asset retirement obligation	0.17	+10%	0.16	N/M	—
Subtotal	14.84	+13%	13.12	+24%	10.59
Marketing and midstream operating costs and expenses (1)	5.34	+4%	5.15	+20%	4.29
Depreciation and amortization of non-oil and gas properties (1)	0.60	+9%	0.55	+0%	0.55
General and administrative expenses (1)	1.11	-18%	1.35	+16%	1.16
Expenses related to mergers (1)	—	N/M	0.03	N/M	—
Reduction of carrying value of oil and gas properties (1)	—	N/M	0.49	-86%	3.45
Total	$ 21.89	+6%	20.69	+3%	20.04

(1) Though per Boe amounts for these expense items may be helpful for profitability trend analysis, these expenses are not directly attributable to production volumes.
(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 meaningful.

Oil, Gas and NGL Production and Operating Expenses *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. With the increase in oil, gas and NGL prices, more well workovers and repairs and maintenance costs are performed to either maintain or improve production volumes. The higher prices also resulted in increased power and fuel costs.

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

2003 vs. 2002 Lease operating expenses increased $303 million in 2003. The April 2003 Ocean merger accounted for $199 million of the increase. Lease operating expenses on our historical properties increased $120 million, due to an increase in well workover expenses and power, fuel, casualty insurance and repairs and maintenance costs. Additionally, changes in the Canadian-to-U.S. dollar exchange rate resulted in a $44 million increase in costs. These increases were partially offset by a decrease of $60 million due to property divestitures in 2002.

The increase in lease operating expenses per Boe is primarily related to increased well workover expenses and power, fuel and repairs and maintenance costs, as well as the changes in the Canadian-to-U.S. dollar exchange rate. With the increase in oil, gas and NGL prices, more well workovers and repairs and maintenance costs are performed to either maintain or improve production volumes. The higher prices also resulted in increased power and fuel costs.

As stated previously, most U.S. production taxes are based on a fixed percentage of revenues. Therefore, the 79% increase in domestic oil, gas and NGL revenues was the primary cause of the $93 million production tax increase.

Depreciation, Depletion and Amortization of Oil and Gas Properties ("DD&A") DD&A of oil and gas properties is calculated as the percentage of total proved reserve volumes produced during the year, multiplied by the net capitalized investment plus future development costs in those reserves (the "depletable base"). 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.

2004 vs. 2003 Oil and gas property related DD&A increased $473 million in 2004. An increase in the combined U.S., Canadian and international 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.

2003 vs. 2002 Oil and gas property related DD&A increased $562 million in 2003. An increase in the combined U.S., Canadian and international DD&A rate from $5.88 per BOE in 2002 to $7.33 per BOE in 2003 caused oil and gas property related DD&A to increase by $331 million. The increase in the DD&A rate is primarily related to the April 2003 Ocean merger, higher finding and development costs and changes in the Canadian-to-U.S. dollar exchange rate. A 21% increase in 2003 oil, gas and NGL production caused DD&A to increase $231 million.

Accretion of Asset Retirement Obligation Effective January 1, 2003, Devon adopted Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations,* 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 balance sheet. The asset retirement cost is depreciated using a systematic and rational method similar to that used for the associated property and equipment.

Because the asset retirement obligation is recorded at its discounted present value, Devon now records accretion expense to reflect the increase in the asset retirement obligation due to the passage of time. We recorded $44 million and $36 million of such accretion expense during 2004 and 2003, respectively.

Marketing and Midstream Operating Costs and Expenses *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 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.

2003 vs. 2002 Marketing and midstream operating costs and expenses increased $366 million in 2003. Of this increase, approximately $347 million was the result of an increase in prices paid for gas and NGLs. An increase in third-party processed NGL volumes caused the remaining increase in 2003 costs and expenses. The increase in volumes was primarily related to new drilling and development in the Barnett Shale properties and an additional 24 days of production in 2003 due to the timing of the January 2002 Mitchell merger, partially offset by volumes lost as a result of processing plant dispositions.

General and Administrative Expenses ("G&A") Devon's 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 Devon serves 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,				
		2004	2004 vs 2003	2003	2003 vs 2002	2002
				($ IN MILLIONS)		
Gross G&A	$	549	+5%	524	+35%	387
Capitalized G&A		(172)	+22%	(140)	+44%	(97)
Reimbursed G&A		(100)	+29%	(77)	+9%	(71)
Net G&A	$	277	-10%	307	+40%	219

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, Devon 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 a $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.

2003 vs. 2002 Gross G&A increased $137 million. This increase was primarily related to the increased activities resulting from the April 2003 Ocean merger, which added $92 million of costs and increased compensation and benefit costs. Included in the increase of compensation and benefit costs is $14 million related to an increase in pension related costs.

The increase in capitalized G&A of $43 million was primarily related to the April 2003 Ocean merger. Reimbursed G&A increased $6 million. The increase in reimbursed amounts was primarily related to the April 2003 Ocean merger, partially offset by a decline in reimbursements related to the 2002 property divestitures.

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 test is imposed separately by country.

In calculating future net revenues, current 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. Devon has entered into various derivative instruments that are accounted for as cash flow hedges. These instruments, which consist of price swaps and costless price collars, and the related future production volumes, are discussed in Note 12. The effect of these hedges has been considered in calculating the full cost ceiling limitations as of December 31, 2004. These hedges reduced the full cost ceiling limitations for the United States, Canada and Equatorial Guinea as of the end of 2004 by $102 million, $77 million and $76 million, respectively. However, the 2004 capitalized costs in these countries did not exceed the related ceiling limitations, with or without the effects of the hedges.

The calculation also dictates the use of a 10% discount factor. The costs to be recovered are compared to the ceiling on a quarterly basis. If the costs to be recovered exceed the ceiling, the excess is written off as an expense, except as discussed in the following paragraph.

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.

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. We estimate such fair value using our 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.

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.

During 2003 and 2002, we reduced the carrying value of our oil and gas properties by $68 million and $651 million, respectively, due to the full cost ceiling limitations. The after-tax effects of these reductions in 2003 and 2002 were $36 million and $371 million, respectively. The following table summarizes these reductions by geographic area.

		YEAR ENDED DECEMBER 31,			
		2003		2002	
		GROSS	NET OF TAXES	GROSS	NET OF TAXES
			(IN MILLIONS)		
Canada	$	—	—	651	371
International		68	36	—	—
Total	$	68	36	651	371

The 2003 reduction in carrying value was related to properties in Egypt, Russia and Indonesia. 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. As a result, our Egyptian, Russian and Indonesian costs to be recovered exceeded the related ceiling value by $26 million, $9 million and $1 million, respectively. These after-tax amounts resulted in pre-tax reductions of the carrying values of our Egyptian, Russian and Indonesian oil and gas properties of $45 million, $19 million and $4 million, respectively, in the fourth quarter of 2003.

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 $43 million charge associated with the impairment of these properties. The after-tax effect of this reduction was $38 million.

The 2002 Canadian reduction was primarily the result of lower prices. The recorded fair values of oil and gas properties added from the Anderson acquisition in 2001 were based on expected future oil and gas prices. These expected prices were higher than the June 30, 2002 prices used to calculate the Canadian ceiling.

Based on oil, natural gas and NGL cash market prices as of June 30, 2002, Devon's Canadian costs to be recovered exceeded the related ceiling value by $371 million. This after-tax amount resulted in a pre-tax reduction of the carrying value of our Canadian oil and gas properties of $651 million in the second quarter of 2002. This reduction was the result of a sharp drop in Canadian gas prices during the last half of June 2002. The end of June reference prices used in the Canadian ceiling calculation, expressed in Canadian dollars based on an exchange ratio of $0.6585, were a NYMEX price of C$40.79 per barrel of oil and an AECO price of C$2.17 per MMBtu. The cash market prices of natural gas increased during the month of July 2002 prior to Devon's release of our second quarter results. However, this increase was not sufficient to offset the entire reduction calculated as of June 30.

Other Income (Expenses)

The details of the changes in other income (expenses) between 2002 and 2004 are shown in the table below.

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
		(IN MILLIONS)	
Other income (expenses):			
Interest based on debt outstanding	$ (513)	(531)	(499)
Accretion of debt discount, net	(2)	(3)	(13)
Facility and agency fees	(2)	(1)	(2)
Amortization of capitalized loan costs	(22)	(12)	(8)
Capitalized interest	70	50	4
Early retirement premiums	—	—	(8)
Other	(6)	(5)	(7)
Total interest expense	(475)	(502)	(533)
Dividends on subsidiary's preferred stock	—	(2)	—
Effects of changes in foreign currency exchange rates	23	69	1
Change in fair value of derivative financial instruments	(62)	1	28
Impairment of ChevronTexaco Corporation common stock	—	—	(205)
Other income	103	37	34
Total	$ (411)	(397)	(675)

A discussion of the significant other income (expense) items follows.

Interest Expense *2004 vs. 2003* The average debt balance outstanding decreased from $8.9 billion in 2003 to $8.5 billion in 2004 causing interest expense to decrease $21 million. The decrease in average debt outstanding was due to debt repayments during 2004. The average interest rate on outstanding debt was approximately 6.0% in both periods. However, a slightly higher rate in 2004 caused interest expense to increase $3 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 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 $16 million of debt issuance costs expensed in 2004. The $16 million related to the early repayment of the outstanding balance under the $3 billion term loan credit facility in the second quarter of 2004.

2003 vs. 2002 The average debt balance outstanding increased from $8.3 billion in 2002 to $8.9 billion in 2003 causing interest expense to increase $32 million. The increase in average debt outstanding was attributable primarily to the debt assumed as a result of the April 2003 Ocean merger. The average interest rate on outstanding debt was 6.0% in both periods.

Other items included in interest expense that are not related to the debt balance outstanding were $63 million lower in 2003. Of this decrease, $46 million related to the capitalization of interest, $10 million related to lower net accretion and $8 million related to the loss on the early extinguishment of the 8.75% senior notes in 2002. The increase in interest capitalized was primarily related to additional unproved properties acquired from the April 2003 Ocean merger.

Effects of Changes in Foreign Currency Exchange Rates Our Canadian subsidiary, which has designated the Canadian dollar as its functional currency, has certain fixed-rate senior notes which are denominated in U.S. dollars. Changes in the exchange rate between the U.S. dollar and the Canadian dollar while the notes are outstanding increase or decrease the expected amount of Canadian dollars eventually required to repay the notes. In addition, Devon's 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 are required to be included in determining net earnings for the period in which the exchange rate changes. 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. The increase in the Canadian-to-U.S. dollar exchange rate from $0.6279 at December 31, 2001 to $0.6331 at December 31, 2002 resulted in a $1 million gain.

Impairment of ChevronTexaco Corporation Common Stock in 2002 In the fourth quarter of 2002, Devon recorded a $205 million other-than-temporary impairment of our investment in 14.2 million shares of ChevronTexaco common stock. We acquired these shares in the August 1999 acquisition of PennzEnergy Company. The shares are deposited with an exchange agent for possible exchange for $760 million of debentures that are exchangeable into the ChevronTexaco shares. The debentures, which mature in August 2008, were also assumed by Devon in the 1999 PennzEnergy acquisition.

At the closing date of the PennzEnergy acquisition, we initially recorded the ChevronTexaco common shares at their fair value, which was $47.69 per share, or an aggregate value of $677 million. Since then, as the ChevronTexaco shares have fluctuated in market value, the value of the shares on Devon's balance sheet has been adjusted to the applicable market value. Through September 30, 2002, any decreases in the value of the ChevronTexaco common shares were determined by Devon to be temporary in nature. Therefore, the changes in value were recorded directly to stockholders' equity and were not recorded in our results of operations through September 30, 2002.

The determination that a decline in value of the ChevronTexaco shares is temporary or other than temporary is subjective and influenced by many factors. Among these factors are the significance of the decline as a percentage of the original cost and the length of time the stock price has been below original cost. Other factors are the performance of the stock price in relation to the stock price of its competitors within the industry and the market in general, and whether the decline is attributable to specific adverse conditions affecting ChevronTexaco.

Beginning in July 2002, the market value of ChevronTexaco common stock began a significant decline. The price per share decreased from $44.25 at June 30, 2002, to $34.63 per share at September 30, 2002, and to $33.24 per share at December 31, 2002. The year-end price of $33.24 represented a 25% decline since June 30, 2002, and a 30% decline from the original valuation in August 1999. As a result of the decline in value during the fourth quarter of 2002, Devon determined that the decline was other than temporary, as that term is defined by accounting rules. Therefore, the $205 million cumulative decrease in the value of the ChevronTexaco common shares from the initial acquisition in August 1999 to December 31, 2002, was recorded as a noncash charge to Devon's results of operations in the fourth quarter of 2002. Net of the applicable tax benefit, the charge reduced our net earnings by $128 million.

The share price of ChevronTexaco common stock has increased to $43.19 at December 31, 2003 and $52.51 at December 31, 2004. As a result, the market value of Devon's investment in ChevronTexaco common stock increased $273 million from December 31, 2002 to December 31, 2004. The changes in the value of the shares since December 31, 2002, net of applicable taxes, have been recorded directly to stockholders' equity. However, depending on the future performance of ChevronTexaco's common stock, Devon may be required to record additional noncash charges in future periods if the value of such stock declines, and we determine that such declines are other than temporary.

Other Income *2004 vs. 2003* Other income increased $66 million in 2004. Other income increased $37 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

2004 vs. 2003 Devon's 2004 effective financial tax rate attributable to continuing operations was an expense of 34% compared to an expense of 23% in 2003. Both the 2004 and 2003 rates benefited from Canadian statutory rate reductions. These rate reductions resulted in a $36 million and $218 million benefit being recorded in 2004 and 2003, respectively, related to the lower tax rates being applied to deferred tax liabilities outstanding as of the beginning of the year. Excluding the effects of the Canadian rate reductions in 2004 and 2003 and the reduction of carrying value of oil and gas properties in 2003, the effective financial tax expense rates were 35% and 33% in 2004 and 2003, respectively. The 2004 rate was equal to the statutory federal tax rate primarily due to the effect of state income taxes offset by the tax benefits of certain foreign deductions. The 2003 rate was lower than the statutory federal tax rate primarily due to the tax benefits of certain foreign deductions.

2003 vs. 2002 Devon's 2003 effective financial tax rate attributable to continuing operations was an expense of 23% compared to a benefit of 144% in 2002. The 2003 rate benefited from a statutory rate reduction enacted by the Canadian government. Excluding the effects of the 2003 Canadian rate reduction, the impairment of ChevronTexaco stock in 2002 and the reduction of carrying value of oil and gas properties in 2003 and 2002, the effective financial tax expense rates were 33% and 23% in 2003 and 2002, respectively. These rates in both years were lower than the statutory federal tax rate primarily due to the tax benefits of certain foreign deductions.

Results of Discontinued Operations

On April 18, 2002, we sold our Indonesian operations to PetroChina Company Limited for total cash consideration of $250 million. On October 25, 2002, we sold our Argentine operations to Petroleo Brasileiro S.A. for total cash consideration of $90 million. On January 27, 2003, we sold our Egyptian operations to IPR Transoil Corporation for total cash consideration of $7 million.

As a result, we reclassified our Indonesian, Argentine and Egyptian activities as discontinued operations. This reclassification affects not only the 2002 presentation of financial results, but also the presentation of all prior periods' results. Subsequent to the sale of our Egyptian and Indonesian operations, we 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 in both 2003 and 2004.

Following are the components of the net results of discontinued operations for the year 2002.

		(IN MILLIONS)
Net gain on sale of discontinued operations	$	31
Earnings from discontinued operations before income taxes		23
Income tax expense		9
Net results of discontinued operations	$	45

Cumulative Effect of Change in Accounting Principle

Effective January 1, 2003, we adopted SFAS No. 143 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 ("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 AND LIQUIDITY

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

Sources and Uses of Cash

		2004	2003	2002
			(IN MILLIONS)	
Cash provided by (used in):				
Operating activities	$	4,816	3,768	1,754
Investing activities		(3,634)	(2,773)	(2,046)
Financing activities		(1,001)	(414)	401
Effect of exchange rate changes		39	59	—
Net increase in cash and cash equivalents	$	220	640	109
Cash and cash equivalents at end of year	$	1,152	932	292
Short-term investments at end of year	$	967	341	—

Cash Flows from Operating Activities Net cash provided by operating activities ("operating cash flow") continued to be a primary source of capital and liquidity in 2004. Operating cash flow in 2004 was $4.8 billion compared to $3.8 billion in 2003 and $1.8 billion in 2002. The increases in operating cash flow in 2004 and 2003 were primarily caused by the increases in revenues, partially offset by increased expenses, as discussed in the "Results of Operations" section of this report.

Cash Flows from Investing Activities Net cash used in investing activities was $3.6 billion in 2004 compared to $2.8 billion in 2003 and $2.0 billion in 2002. The increases in cash used in investing activities were directly related to increased capital expenditures net of proceeds from the sale of property and equipment, as well as increases in short-term investment balances of $626 million and $341 million in 2004 and 2003, respectively.

Capital expenditures in 2004 were $3.1 billion. This total includes $3.0 billion for the acquisition, drilling or development of oil and gas properties. These amounts compare to capital expenditures of $2.6 billion in 2003 and $3.4 billion in 2002. The 2003 amount included $2.5 billion for the acquisition, drilling or development of oil and gas properties. The 2002 amount included $1.7 billion related to the January 2002 Mitchell merger and $1.6 billion for other acquisitions and the drilling or development of oil and gas properties.

The April 2003 Ocean merger did not affect 2003 capital expenditures because the consideration given was Devon common stock. This differs from the January 2002 Mitchell merger, in which the consideration given was both Devon common stock and cash. As a result, the Mitchell merger did have an impact on capital expenditures paid in cash.

Proceeds from sales of property and equipment were $95 million, $179 million and $1.4 billion in 2004, 2003 and 2002, respectively. The 2002 amount includes proceeds from the sales of certain non-core oil and gas properties which were used to pay down debt.

Cash Flows from Financing Activities Net cash used in financing activities during 2004 was $1.0 billion compared to $414 million in 2003. The increase in cash used in financing activities from 2003 to 2004 was directly related to increased debt repayments net of borrowings. The increase was also related to increased common stock dividends and the repurchase of common stock, partially offset by an increase in proceeds from the issuance of common stock. Net cash provided by financing activities was $401 million in 2002, consisting primarily of net proceeds from borrowings of long-term debt.

During 2004, Devon retired $973 million of debt. This was primarily related to the $211 million 6.75% notes due February 15, 2004 and the $125 million 8.05% notes due June 15, 2004, and payment of the remaining $635 million outstanding on the $3 billion term loan credit facility. During 2003, principal payments on long-term debt, net of proceeds from borrowings of long-term debt, were $521 million. This net amount related to long-term debt assumed in the April 2003 Ocean merger.

During 2002, Devon had net borrowings of $410 million. These net borrowings were primarily related to the $2 billion borrowed under the $3 billion term loan credit facility to pay for the cash portion of the Mitchell merger. This was partially offset primarily by the repayment of $1.1 billion of this facility with proceeds from the 2002 property sales, the early retirement of the 8.75% notes due June 15, 2007 and certain Canadian notes, and the retirement of Devon's outstanding borrowings under its commercial paper and revolving credit facilities.

Devon's common stock dividends were $97 million, $39 million and $31 million in 2004, 2003 and 2002, respectively. We also paid $10 million of preferred stock dividends in 2004, 2003 and 2002. The increase in common stock dividends from 2003 to 2004 was primarily related to a 100% increase in the quarterly dividend rate and the increased number of shares outstanding. Effective with the first quarter 2004 dividend payment, Devon increased its quarterly dividend rate from $0.025 per share to $0.05 per share. The increase in shares outstanding was primarily related to the April 2003 Ocean merger.

In conjunction with the stock buyback program announced September 27, 2004, Devon repurchased 5 million shares at a total cost of $189 million during 2004.

Devon received $268 million, $155 million and $32 million from shares issued for employee stock options exercised during 2004, 2003 and 2002, respectively.

Liquidity

At December 31, 2004, Devon's unrestricted cash and cash equivalents and short-term investments totaled $2.1 billion. During 2004, 2003 and 2002, such balances increased $846 million, $981 million and $109 million, respectively.

Historically, Devon's 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. Over the next 12 months, another major source of liquidity will be proceeds from the sales of oil and gas properties as announced September 27, 2004. After-tax sale proceeds from the divestiture program are expected to range between $1.0 billion and $1.5 billion. We expect the combination of these sources of capital will be more than adequate to fund future capital expenditures, the common stock buyback program, and other contractual commitments as discussed later in this section.

Operating Cash Flow Devon's 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.

To mitigate some of the risk inherent in oil and natural gas prices, Devon has utilized price collars to set minimum and maximum prices on a portion of its production. Additionally, we have entered into various financial price swap contracts and fixed-price physical delivery contracts to fix the price to be received for a portion of future oil and natural gas production. The table below provides the volumes associated with these various arrangements as of December 31, 2004.

	PRICE COLLARS	PRICE SWAP CONTRACTS	FIXED-PRICE PHYSICAL DELIVERY CONTRACTS	TOTAL
Oil production (MMBbls)				
2005	18	8	—	26
Natural gas production (Bcf)				
2005	35	3	18	56
2006	—	—	18	18

In addition to the above quantities, we have fixed-price physical delivery contracts covering Canadian natural gas production for the years 2007 through 2011 ranging from 8 Bcf to 14 Bcf per year. Also, Devon has a fixed-price physical delivery contract covering 4 Bcf and 3 Bcf of International natural gas production in 2007 and 2008, respectively. From 2012 through 2016, we have Canadian natural gas volumes subject to fixed-price contracts, but the yearly volumes are less than 1 Bcf.

It is our policy to only enter into derivative contracts with investment grade rated counterparties deemed by management as competent and competitive market makers. Devon does not hold or issue derivative instruments for speculative trading purposes.

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.

The Senior Credit Facility matures on April 8, 2009, 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 has obtained lender approval to extend the current maturity date of April 8, 2009 to April 8, 2010. This maturity date extension will be effective April 8, 2005, 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 our election, bear interest at various fixed rate options for periods of up to 12 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.

As of December 31, 2004, there were no borrowings under the Senior Credit Facility. The available capacity under the Senior Credit Facility as of December 31, 2004, net of $226 million of outstanding letters of credit, was approximately $1.3 billion.

The Senior Credit Facility contains only one material financial covenant. This covenant requires Devon to maintain a ratio of total funded debt to total capitalization of no more than 65%. The credit agreement contains definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in Devon's consolidated financial statements. Per the agreement, total funded debt excludes the debentures that are exchangeable into shares of ChevronTexaco Corporation common stock. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling property impairments or goodwill impairments. As of December 31, 2004, Devon's ratio as calculated pursuant to this covenant was 33.0%.

Our access to funds from the Senior Credit Facility is not restricted under any "material adverse condition" 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 Devon to report a condition or event having a material adverse effect on Devon, 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 to 90 days, although it can have a maturity of up to 365 days. We had no commercial paper debt outstanding at December 31, 2004.

Debt Ratings Devon receives debt ratings from the major ratings agencies in the United States. In determining our debt rating, 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.

Devon's current debt ratings are BBB with a stable outlook by Standard & Poor's, Baa2 with a stable 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. Certain of Devon's agreements related to its oil and natural gas hedges do contain provisions that could require us to provide cash collateral in situations where our liability under the hedge is above a certain dollar threshold and where our debt rating is below investment grade (BBB- or Baa3). However, Devon's liability under these agreements would only exceed the threshold level in circumstances where the market prices for oil or natural gas were rising. It is unlikely that our debt rating would be subjected to downgrades to non-investment grade levels during such a period of rising oil and natural gas prices.

Devon's cost of borrowing under our Senior Credit Facility is predicated on its 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, 2004, we are not aware of any potential ratings downgrades being contemplated by the rating agencies.

Capital Expenditures In February 2005, Devon announced its 2005 capital expenditures budget. Our 2005 capital expenditures are expected to range from $3.0 billion to $3.5 billion, representing the largest planned use of capital resources for capital investment activities. 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 2005 capital expenditures until later periods or accelerate capital expenditures planned for periods beyond 2005 to achieve the desired balance between sources and uses of liquidity. Based upon current oil and natural gas price expectations for 2005, we anticipate that our capital resources will be more than adequate to fund 2005 capital expenditures.

Common Stock Buyback Program During 2004 Devon repurchased five million shares of its common stock, and we intend to repurchase up to 45 million additional shares in 2005 in conjunction with a stock buyback program announced in September 2004. The shares will be repurchased with operating cash flow and proceeds from the planned sales of oil and gas properties announced on September 27, 2004. The stock repurchase program may be discontinued at any time.

Contractual Obligations A summary of Devon's contractual obligations as of December 31, 2004, is provided in the following table.

	PAYMENTS DUE BY YEAR						
	2005	2006	2007	2008	2009	AFTER 2009	TOTAL
				(IN MILLIONS)			
Long-term debt	$ 926	667	400	761	177	5,025	7,956
Interest expense	506	470	444	426	390	4,582	6,818
Asset retirement obligations	46	59	52	61	69	452	739
Drilling and facility obligations	409	132	4	16	3	5	569
Firm transportation agreements	91	70	60	47	35	145	448
Operating leases:							
Office and equipment leases	35	30	28	25	23	69	210
Spar leases	15	15	15	15	14	228	302
FPSO leases	20	20	20	19	13	—	92
Other	7	6	5	5	3	1	27
Total	$ 2,055	1,469	1,028	1,375	727	10,507	17,161

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. Devon has sufficient production to utilize the majority of these transportation services.

Devon has two offshore platform spars that are being used in the development of the Nansen and Boomvang fields in the Gulf of Mexico. The operating leases are for 20-year terms and contain various options whereby we may purchase the lessors' interests in the spars. We have guaranteed that the spars will have residual values at the end of the operating leases equal to at least 10% of the fair value of the spars at the inception of the leases. The total guaranteed value is $20 million in 2022. However, such amount may be reduced under the terms of the lease agreements.

We also have two floating, production, storage and offloading facilities ("FPSO") that are being leased under operating lease arrangements. One FPSO is being used in the Panyu project offshore China. The other is being used in the Zafiro field offshore Equatorial Guinea. The China lease expires in September 2009 and the Equatorial Guinea lease expires in July 2009.

The above table does not include $226 million of letters of credit that have been issued by commercial banks on Devon's behalf. These letters of credit, if funded, would become borrowings under our revolving credit facility. Most of these letters of credit have been granted by Devon's financial institutions to support our international and Canadian drilling commitments. The $8 billion of long-term debt shown in the table excludes $1 million of net discounts and a $9 million fair value adjustment. Both of these items are included in the December 31, 2004, book balance of the debt.

Pension Funding and Obligations Devon's 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, $35 million and $16 million in 2004, 2003 and 2002, respectively. We estimate that our pension expense will approximate $26 million in 2005.

As compared to the "projected benefit obligation," Devon's qualified and nonqualified defined benefit plans were underfunded by $132 million and $137 million at December 31, 2004 and 2003, respectively. The decrease in the underfunded amount during 2004 was primarily caused by gains on investments and $70 million of cash contributions made to the plans by Devon. These were partially offset by increases in the benefit obligations. A detailed reconciliation of the 2004 activity is included in Note 13 to the accompanying consolidated financial statements. Of the $132 million underfunded status at the end of 2004, $109 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, 2004, these trusts had investments with a market value of $60 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 $11 million at December 31, 2004. 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 2005, Devon expects its contributions to the plan to be less than $10 million.

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. Devon believes 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 8.34% and 8.25% at December 31, 2004 and 2003, 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 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.

We believe that our long-term asset allocation on average will 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 8.34% to 7.34%) would increase the expected 2005 pension expense by approximately $4 million.

Devon discounted its future pension obligations using a weighted average rate of 5.74% at December 31, 2004, compared to 6.23% at December 31, 2003. 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 5.74% to 5.49%) would increase our pension liability at December 31, 2004, by approximately $18 million, and increase estimated 2005 pension expense by approximately $2 million.

At December 31, 2004, Devon had unrecognized actuarial losses of $155 million. These losses will be recognized as a component of pension expense in future years. We estimate that approximately $9 million and $8 million of the unrecognized actuarial losses will be included in pension expense in 2005 and 2006, respectively. The $9 million estimated to be recognized in 2005 is a component of the total estimated 2005 pension expense of $26 million referred to earlier in this discussion.

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Full Cost Ceiling Calculations

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 Devon's capitalized costs are in excess of the calculated ceiling, the excess must be written off as an expense. The ceiling limitation is imposed separately for each country in which we have oil and gas properties.

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 by outside petroleum consultants, while other reserve estimates are prepared by Devon's engineers. See Note 18 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 2% 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 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 Devon's 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.

The ceiling calculation also dictates that a 10% discount factor is to be used to calculate the present value of net cash flows.

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 cyclical. On any particular day at the end of a quarter, prices can be either substantially higher or lower than Devon's 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

Devon enters into oil and gas derivative financial instruments to manage its exposure to oil and gas price volatility. We have also entered into 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.

A substantial portion of our derivatives consists of contracts that hedge the price of future oil and natural gas production. These derivative contracts are cash flow hedges that qualify 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 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. 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 we fail to meet the requirements for using hedge accounting treatment, the changes in fair value of these hedging instruments would not be recorded directly to equity but in the consolidated results of operations.

The estimates of the fair values of Devon's 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 Devon's 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

Devon has 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.

There are various assumptions made by Devon 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. Devon's 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 analyses. Forecasts of future prices from independent third parties are noted when Devon makes its 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 Devon's cost of capital.

Devon also applies these same general principles in arriving at 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 Devon's 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 Devon assumes in the acquisition, and this debt must be recorded at the estimated fair value as if Devon 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, Devon's 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 were also acquired by Devon 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, Devon performs other quantitative analysis 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. These comparable company multiples are compared 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. The comparable transaction multiples are compared 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. Devon uses this information to determine the mean and median premiums paid and compares 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 Devon's 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 Devon's price forecast that was used to originally determine fair value. A full cost ceiling writedown would have no effect on liquidity or capital resources in that period. However, it would adversely affect our future results of operations. The full cost ceiling writedown is a noncash charge. As discussed in the "Capital Resources and Liquidity" section, 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, Devon's annual revisions to its reserve estimates have averaged approximately 2%. 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

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.

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 Devon's 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 Devon's reserve estimates previously set forth.

IMPACT OF RECENTLY ISSUED ACCOUNTING STANDARDS NOT YET ADOPTED

In December 2004, the Financial Accounting Standards Board (''FASB'') issued SFAS No. 123(R), ''Share-Based Payment,'' 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 third quarter of 2005 and anticipate adopting SFAS No. 123(R) using the modified prospective method. Under this method, Devon will recognize compensation expense for all stock-based awards granted or modified on or after July 1, 2005, as well as any previously granted awards that are not fully vested as of July 1, 2005. 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. We are currently assessing the impact of adopting SFAS No. 123(R) on our consolidated results of operations. However, we do not expect such impact to be material upon adoption in the third quarter of 2005.

In December 2004, the FASB issued Staff Position No. 109-2, "Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004" ("FSP No. 109-2"). The American Jobs Creation Act of 2004 (the "Act"), signed into law on October 22, 2004, provides for a special one-time tax deduction, or dividend received deduction ("DRD"), of 85% of qualifying foreign earnings that are repatriated in either a company's last tax year that began before the enactment date or the first tax year that begins during the one-year period beginning on the enactment date. FSP 109-2 provides entities additional time to assess the effect of repatriating foreign earnings under the Act for purposes of applying SFAS No. 109, "Accounting for Income Taxes," which typically requires the effect of a new tax law to be recorded in the period of enactment. In the first quarter of 2005, Devon's board of directors approved the repatriation of $500 million of earnings from Canadian operations which will be taxed at a reduced income tax rate caused by the DRD. As a result, Devon will recognize additional current income tax expense of approximately $30 million in the first quarter of 2005.

SEC INQUIRY RELATING TO EQUATORIAL GUINEA

On August 6, 2004, the SEC notified Devon that it was conducting an inquiry into payments made to the government of Equatorial Guinea, or to officials and persons affiliated with officials of the government of Equatorial Guinea. This inquiry follows an investigation and public hearing conducted by the United States Senate Permanent Subcommittee on Investigations, which reviewed the transactions of various foreign governments, including that of Equatorial Guinea, with Riggs Bank. The investigation and hearing also reviewed the operations of those U.S. oil companies having interests in Equatorial Guinea, including Devon. Devon is cooperating with the SEC inquiry.

2005 ESTIMATES

The forward-looking statements provided in this discussion are based on management's examination of historical operating trends, the information which was used to prepare the December 31, 2004 reserve reports and other data in our 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.

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 below.

Also, the financial results of our foreign operations are subject to currency exchange rate risks. Additional risks are discussed below in the context of line items most affected by such risks.

Specific Assumptions and Risks Related to Price and Production Estimates

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 our control and are difficult to predict. In addition to volatility in general, Devon's 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, our financial results and resources are highly influenced by price volatility.

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

Estimates for our future processing and transport of oil, natural gas and NGLs are based on the assumption that market demand and prices will continue at levels that allow for profitable processing and transport of these products. There can be no assurance of such stability.

The production, transportation, processing and marketing of oil, natural gas and NGLs are complex processes which are subject to disruption from many causes. These causes include transportation and processing availability, mechanical failure, human error, meteorological events including, but not limited to, hurricanes, and numerous other factors. The following forward-looking statements were prepared assuming demand, curtailment, producibility and general market conditions for Devon's oil, natural gas and NGLs during 2005 will be substantially similar to those of 2004, unless otherwise noted.

Unless otherwise noted, all of the following dollar amounts are expressed in U.S. dollars. Amounts related to Canadian operations have been converted to U.S. dollars using a projected average 2005 exchange rate of $0.82 U.S. to $1.00 Canadian. The actual 2005 exchange rate may vary materially from this estimate. Such variations could have a material effect on the following estimates.

Though we have completed several major property acquisitions and dispositions in recent years, these transactions are opportunity driven. Thus, the following forward-looking data excludes the financial and operating effects of potential property acquisitions or divestitures, except as discussed in "Property Acquisitions and Divestitures," during the year 2005. The timing and ultimate results of such acquisition and divestiture activity is difficult to predict, and may vary materially from that discussed in this report.

Geographic Reporting Areas for 2005

The following estimates of production, average price differentials 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.

Year 2005 Potential Operating Items

The estimates related to oil, gas and NGL production, operating costs and DD&A set forth in the following paragraphs are based on estimates for Devon's properties other than those that have been designated for possible sale (See "Property Acquisitions and Divestitures"). Therefore, the following estimates exclude the results of the potential sale properties for the entire year.

Oil, Gas and NGL Production Set forth in the following paragraphs are individual estimates of Devon's oil, gas and NGL production for 2005. On a combined basis, Devon estimates its 2005 oil, gas and NGL production will total 217 MMBoe. Of this total, approximately 92% is estimated to be produced from reserves classified as "proved" at December 31, 2004.

Oil Production We expect our oil production in 2005 to total 60 MMBbls. Of this total, approximately 95% is estimated to be produced from reserves classified as "proved" at December 31, 2004. The expected production by area is as follows:

	(MMBBLS)
United States Onshore	12
United States Offshore	10
Canada	12
International	26

Oil Prices – Fixed Through various price swaps, Devon has fixed the price it will receive in 2005 on a portion of its oil production. 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 Devon.

	BBLS/DAY	PRICE/BBL	MONTHS OF PRODUCTION
United States Offshore	10,000	$ 27.17	Jan – Dec
Canada	6,000	$ 27.26	Jan – Dec
International	6,000	$ 25.88	Jan – Dec

Oil Prices – Floating Devon's 2004 average prices for each of its 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 West Texas Intermediate crude oil delivered at Cushing, Oklahoma.

	EXPECTED RANGE OF OIL PRICES AS A % OF NYMEX PRICE
United States Onshore	90% to 95%
United States Offshore	91% to 96%
Canada	76% to 81%
International	84% to 90%

We have also entered into costless price collars that set a floor and ceiling price for a portion of our 2005 oil production that is otherwise subject to floating prices. The floor and ceiling prices related to domestic and Canadian oil production are based on the NYMEX price. The floor and ceiling prices related to international oil production are based on the Brent price. If the NYMEX or Brent price is outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. As long as Devon meets the ongoing requirements of hedge accounting for its derivatives, any such settlements will either increase or decrease Devon's oil revenues for the period. Because our oil volumes are often sold at prices that differ from the NYMEX or Brent price due to differing quality (i.e., sweet crude versus heavy or sour crude) and transportation costs from different geographic areas, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

The international oil prices shown in the following table have been adjusted to a NYMEX-based price, using our estimates of 2005 differentials between NYMEX and the Brent price upon which the collars are based.

To simplify the presentation, Devon's costless collars as of December 31, 2004, have been aggregated in the following table according to similar floor prices and similar ceiling prices. The floor and ceiling prices shown are weighted averages of the various collars in each aggregated group.

		WEIGHTED AVERAGE		
AREA	BBLS/DAY	FLOOR PRICE PER BBL	CEILING PRICE PER BBL	MONTHS OF PRODUCTION
United States Onshore	3,000	$ 22.00	$ 28.25	Jan – Dec
United States Offshore	17,000	$ 22.00	$ 27.62	Jan – Dec
Canada	15,000	$ 22.00	$ 28.28	Jan – Dec
International	15,000	$ 23.50	$ 29.61	Jan – Dec

Gas Production We expect our 2005 gas production to total 804 Bcf. Of this total, approximately 90% is estimated to be produced from reserves classified as "proved" at December 31, 2004. The expected production by area is as follows:

	(BCF)
United States Onshore	460
United States Offshore	82
Canada	255
International	7

Gas Prices – Fixed Through various price swaps and fixed-price physical delivery contracts, we have fixed the price we will receive in 2005 on a portion of our natural gas production. 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 Devon, and the prices have also been adjusted for the Btu content of the gas hedged.

	MCF/DAY	PRICE/MCF	MONTHS OF PRODUCTION
United States Onshore	7,343	$ 3.40	Jan – Dec
Canada	38,578	$ 2.89	Jan – Jun
Canada	38,578	$ 2.96	Jul – Dec
International	12,000	$ 2.35	Jan – Dec

Gas Prices – Floating For the natural gas production for which prices have not been fixed, Devon's 2005 average prices for each of its 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 LESS THAN NYMEX PRICE
United States Onshore	84% to 93%
United States Offshore	98% to 107%
Canada	80% to 88%
International	50% to 60%

We have also entered into costless price collars that set a floor and ceiling price for a portion of our 2005 natural gas production that otherwise is subject to floating prices. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's gas revenues for the period. Because our gas volumes are often sold at prices that differ from the related regional indices, and due to differing Btu contents of gas produced, the floor and ceiling prices of the various collars do not reflect actual limits of our realized prices for the production volumes related to the collars.

The prices shown in the following table have been adjusted to a NYMEX-based price, using our estimates of 2005 differentials between NYMEX and the specific regional indices upon which the collars are based. The floor and ceiling prices related to the collars are based on various regional first-of-the-month price indices as published monthly by *Inside FERC*.

To simplify presentation, Devon's costless collars have been aggregated in the following table according to similar floor prices and similar ceiling prices. The floor and ceiling prices shown are weighted averages of the various collars in each aggregated group.

		WEIGHTED AVERAGE		
AREA	MMBTU/DAY	FLOOR PRICE PER MMBTU	CEILING PRICE PER MMBTU	MONTHS OF PRODUCTION
United States Onshore	40,000	$ 4.04	$ 7.00	Jan – Jun
United States Offshore	40,000	$ 3.50	$ 7.50	Jan – Dec
United States Offshore	70,000	$ 4.09	$ 7.00	Jan – Jun

NGL Production Devon expects its 2005 production of NGLs to total 23 MMBbls. Of this total, 93% is estimated to be produced from reserves classified as "proved" at December 31, 2004. The expected production by area is as follows:

	(MMBBLS)
United States Onshore	17
United States Offshore	1
Canada	5

Marketing and Midstream Revenues and Expenses Devon's marketing and midstream revenues and expenses are derived primarily from its 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 NGL contract provisions, and the amount of repair and workover activity required to maintain anticipated transportation and 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 2005 marketing and midstream revenues will be between $1.26 billion and $1.40 billion, and marketing and midstream expenses will be between $1.00 billion and $1.10 billion.

Production and Operating Expenses Devon's 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 Devon's property base, changes in production tax rates, changes in the general price level of services and materials that are used in the operation of the properties and the amount of repair and workover activity required. 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 2005 lease operating expenses (including transportation costs) will be between $1.155 billion and $1.225 billion and production taxes will be between 3.25% and 3.75% of consolidated oil, natural gas and NGL revenues. This excludes the effect on revenues from hedges, upon which production taxes are not incurred.

Depreciation, Depletion and Amortization ("DD&A") The 2005 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 2005 compared to the costs incurred for such efforts, and the revisions to Devon's year-end 2004 reserve estimates that, based on prior experience, are likely to be made during 2005.

Given these uncertainties, oil and gas property related DD&A expense for 2005 is expected to be between $1.86 billion and $1.94 billion. Based on these DD&A amounts and the production estimates set forth earlier, we expect our oil and gas property related DD&A rate will be between $8.60 per Boe and $9.00 per Boe.

Additionally, we expect depreciation and amortization expense related to non-oil and gas property fixed assets to total between $150 million and $160 million.

Accretion of Asset Retirement Obligation Devon expects its 2005 accretion of its asset retirement obligation to be between $40 million and $45 million.

General and Administrative Expenses ("G&A") G&A includes the costs of many different goods and services used in support of our business. These goods and services are subject to general price level increases or decreases. In addition, Devon's G&A varies with its level of activity and the related staffing needs as well as with the amount of professional services required during any given period. Should our needs or the prices of the required goods and services differ significantly from current expectations, actual G&A could vary materially from the estimate.

The planned property dispositions have further added to the uncertainties around G&A estimates. Devon is currently in the process of determining the appropriate staffing needs subsequent to the dispositions. Specifically excluded from these estimates are both severance related costs and the cost savings that would result from an expected reduction of headcount. Any cost savings from these reductions will be dependent not only on the level of staff reductions, but also on the timing. As a result, until this process is complete, actual 2005 G&A could vary materially from current estimates.

Given these limitations, consolidated G&A in 2005 is expected to be between $260 million and $280 million.

Reduction of Carrying Value of Oil and Gas Properties We follow the full cost method of accounting for our oil and gas properties. Under the full cost method, Devon's net book value of oil and gas properties, less related deferred income taxes (the "costs to be recovered"), may not exceed a calculated "full cost ceiling." The ceiling limitation is the discounted estimated after-tax future net revenues from oil and gas properties plus the cost of properties not subject to amortization. The ceiling is imposed separately by country. In calculating future net revenues, current 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. Such contracts include derivatives accounted for as cash flow hedges. The costs to be recovered are compared to the ceiling on a quarterly basis. If the costs to be recovered exceed the ceiling, the excess 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.

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 cyclical and, on any particular day at the end of a quarter, 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.

Because of the volatile nature of oil and gas prices, it is not possible to predict whether we will incur a full cost writedown in future periods.

Interest Expense Future interest rates and debt outstanding have a significant effect on Devon's interest expense. Additionally, we can only marginally influence the prices we will receive in 2005 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.

The interest expense in 2005 related to our fixed-rate debt, including net accretion of related discounts, will be approximately $430 million. This fixed-rate debt removes the uncertainty of future interest rates from some, but not all, of Devon's 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
7.625% senior notes due in 2005	$ 125	LIBOR plus 237 basis points
10.25% bonds due in 2005	$ 235	LIBOR plus 711 basis points
2.75% notes due in 2006	$ 500	LIBOR less 26.8 basis points
6.55% senior notes due 2006	$ 166 (1)	Banker's Acceptance plus 340 basis points
4.375% senior notes due in 2007	$ 400	LIBOR plus 40 basis points
6.75% senior notes due 2011	$ 400	LIBOR plus 197 basis points

(1) Converted from $200 million Canadian dollars at a Canadian-to-U.S. dollar exchange rate of $0.8308 as of December 31, 2004.

Based on future LIBOR rates as of January 31, 2005, interest expense on our floating rate debt, including net amortization of premiums, is expected to total between $75 million and $85 million in 2005.

Devon's interest expense totals have historically included 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 our 2005 interest expense. Also, we expect to capitalize between $65 million and $75 million of interest during 2005.

Based on the information related to interest expense set forth herein and assuming no material changes in Devon's levels of indebtedness or prevailing interest rates, other than the retirement of debt due to mature in 2005, we expect our 2005 interest expense will be between $445 million and $455 million.

Effects of Changes in Foreign Currency Rates Our Canadian subsidiary has $400 million of fixed-rate senior notes which are denominated in U.S. dollars. Changes in the exchange rate between the U.S. dollar and the Canadian dollar during 2005 will increase or decrease the Canadian dollar equivalent balance of this debt. Such changes in the Canadian dollar equivalent balance of the debt are required to be included in determining net earnings for the period in which the exchange rate changes. Because of the variability of the exchange rate, it is difficult to estimate the effect which will be recorded in 2005. However, based on the December 31, 2004, Canadian-to-U.S. dollar exchange rate of $0.8308 and Devon's forecast 2005 rate of $0.8200, we expect to record an expense of approximately $5 million. The actual 2005 effect will depend on the exchange rate as of December 31, 2005.

Other Revenues Devon's other revenues in 2005 are expected to be between $260 million and $270 million. Included as part of other revenues is a $150 million gain on the sale of certain assets in the first quarter of 2005.

Our estimate of 2005 other revenues does not include the effect of any early settlements or hedge ineffectiveness of outstanding commodity price hedges as a result of the property dispositions. The amount of any settlement gain or loss or hedge ineffectiveness will depend not only on the timing of the property sales but also on the forward prices in effect at that time. As a result, Devon is unable to predict the effect that these early settlements or hedge ineffectiveness may have on its earnings. Under current market conditions, we would expect to record a loss on these early settlements or hedge ineffectiveness.

Income Taxes Our financial income tax rate in 2005 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2005 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 2005's income tax expense regardless of the level of pre-tax earnings that are produced. Given the uncertainty of our pre-tax earnings amount, we estimate that our consolidated financial income tax rate in 2005 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 2005's financial income tax rates.

Property Acquisitions and Divestitures Though Devon has 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.

During 2005, we contemplate the disposition of certain oil and gas properties (the "Disposition Properties"). The Disposition Properties are predominantly properties that are either outside of our core operating areas or otherwise do not fit our current strategic objectives. The Disposition Properties are located in the U.S. and Canada. At this time, we expect the dispositions will occur in the first half of 2005.

The estimates of our 2005 results previously set forth exclude any results from the Disposition Properties. The Disposition Properties' actual contributions to our 2005 operating results will depend upon the timing of the dispositions. The estimated first quarter 2005 results from the Disposition Properties (which are not included in the previous 2005 estimates in this report) are as follows:

	ESTIMATED PRODUCTION – 1ST QUARTER 2005			
	OIL	GAS	NGLs	TOTAL
	(MMBBLS)	(BCF)	(MMBBLS)	(MMBOE)
United States Onshore	0.4	6	0.3	1.7
United States Offshore	1.7	11	0.1	3.6
Canada	0.5	9	—	2.0
Total	2.6	26	0.4	7.3

	EXPECTED RANGE OF EXPENSE – 1ST QUARTER 2005
	(IN MILLIONS)
Lease operating expenses, including transportation	$48 to $50
DD&A expenses	$76 to $78

Not included in these estimates is the effect of any early settlements or hedge ineffectiveness of outstanding commodity price hedges as a result of the dispositions. The amount of any settlement gain or loss or hedge ineffectiveness will depend not only on the timing of the property sales but also on the forward prices in effect at that time. As a result, Devon is unable to predict the effect that these early settlements or hedge ineffectiveness may have on its earnings. Under current market conditions, we would expect to record a loss on these early settlements.

Year 2005 Potential Capital Sources, Uses and Liquidity

Capital Expenditures Devon's 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 Devon's price expectations for its future production, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2005 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, we expect 2005 capital expenditures for drilling and development efforts, plus related facilities, to total between $2.6 billion and $3.0 billion. These amounts include between $390 million and $450 million for drilling and facilities costs related to reserves classified as proved as of year-end 2004. In addition, these amounts include between $1.345 billion and $1.555 billion for other production capital and between $865 million and $995 million for exploration capital. 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.

The following table shows expected drilling and facilities expenditures by geographic area.

	EXPLORATION AND PRODUCTION EXPENDITURES				
	UNITED STATES ONSHORE	UNITED STATES OFFSHORE	CANADA	INTERNATIONAL	TOTAL
			(IN MILLIONS)		
Production capital related to proved reserves	$ 190 - $ 215	$ 85 - $ 95	$ 70 - $ 85	$ 45 - $ 55	$ 390 - $ 450
Other production capital	$ 655 - $ 765	$ 40 - $ 50	$615 - $ 695	$ 35 - $ 45	$1,345 - $1,555
Exploration capital	$ 165 - $ 190	$240 - $265	$310 - $ 345	$150 - $195	$ 865 - $ 995
Total	$1,010 - $1,170	$365 - $410	$995 - $1,125	$230 - $295	$2,600 - $3,000

In addition to the above expenditures for drilling and development, Devon expects to spend between $85 million to $95 million on its marketing and midstream assets, which include its oil pipelines, gas processing plants, CO2 removal facilities and gas transport pipelines. We also expect to capitalize between $165 million and $175 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 $25 million and $30 million for plugging and abandonment charges, and to spend between $70 million and $80 million for other non-oil and gas property fixed assets.

Other Cash Uses Devon's management expects the policy of paying a quarterly common stock dividend to continue. With the current $0.075 per share quarterly dividend rate and 484 million shares of common stock outstanding as of December 31, 2004, dividends are expected to approximate $145 million. Also, Devon has $150 million of 6.49% cumulative preferred stock upon which it will pay $10 million of dividends in 2005.

On September 27, 2004, Devon announced its intention to buy back up to 50 million shares of its common stock in conjunction with a stock buyback program. The shares will be repurchased with cash flow from operations and proceeds from the planned property divestitures. As of February 28, 2005, Devon has repurchased 12.5 million shares at a total cost of $501 million, or $40.04 per share.

Capital Resources and Liquidity Devon's estimated 2005 cash uses, including its drilling and development activities and repurchase of common stock, are expected to be funded primarily through a combination of working capital, operating cash flow and proceeds from its planned property divestitures, with the remainder, if any, funded with borrowings from our credit facility. The amount of operating cash flow to be generated during 2005 is uncertain due to the factors affecting revenues and expenses as previously cited. However, we expect our combined capital resources to be more than adequate to fund our anticipated capital expenditures and other cash uses for 2005. As of December 31, 2004, we had $2.1 billion of cash and short-term investments and $1.3 billion available under our $1.5 billion of credit facilities, net of $0.2 billion of outstanding letters of credit. 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 Devon's 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 Devon views and manages its 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.

Devon periodically enters into financial hedging activities with respect to a portion of its projected oil and natural gas production through various financial transactions which hedge the future prices received. These transactions include financial price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, and costless price collars that set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. These financial hedging activities are intended to support oil and natural gas prices at targeted levels and to manage Devon's exposure to oil and gas price fluctuations.

Devon's total hedged positions on future production as of December 31, 2004 are set forth in the following tables.

Price Swaps Through various price swaps, we have fixed the price we will receive on a portion of our oil and natural gas production in 2005. The following tables include information on this fixed-price production by area. Where necessary, the oil and gas prices related to these swaps have been adjusted for certain transportation costs that are netted against the price recorded by Devon, and the gas price has also been adjusted for the Btu content of the production that has been hedged.

OIL PRODUCTION

AREA	BBLS/DAY	PRICE/BBL	MONTHS OF PRODUCTION
United States Onshore	10,000	$ 27.17	Jan – Dec
Canada	6,000	$ 27.26	Jan – Dec
International	6,000	$ 25.88	Jan – Dec

GAS PRODUCTION

AREA	MCF/DAY	PRICE/MCF	MONTHS OF PRODUCTION
United States Onshore	7,343	$ 3.40	Jan – Dec

Costless Price Collars We have also entered into costless price collars that set a floor and ceiling price for a portion of our 2005 oil production that is otherwise subject to floating prices. The floor and ceiling prices related to domestic and Canadian oil production are based on the NYMEX price. The floor and ceiling prices related to international oil production are based on the Brent price. If the NYMEX or Brent price is outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. As long as Devon meets the ongoing requirements of hedge accounting for its derivatives, any such settlements will either increase or decrease Devon's oil revenues for the period. Because our oil volumes are often sold at prices that differ from the NYMEX or Brent price due to differing quality (i.e., sweet crude versus heavy or sour crude) and transportation costs from different geographic areas, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

We have also entered into costless price collars that set a floor and ceiling price for a portion of our 2005 natural gas production that otherwise is subject to floating prices. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's gas revenues for the period. Because Devon's gas volumes are often sold at prices that differ from the related regional indices, and due to differing Btu contents of gas produced, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

To simplify presentation, our costless collars as of December 31, 2004 have been aggregated in the following tables according to similar floor prices and similar ceiling prices. The floor and ceiling prices shown are weighted averages of the various collars in each aggregated group.

The international oil prices shown in the following table have been adjusted to a NYMEX-based price, using our estimates of 2005 differentials between NYMEX and the Brent price upon which the collars are based.

The natural gas prices shown in the following tables have been adjusted to a NYMEX-based price, using our estimates of future differentials between NYMEX and the specific regional indices upon which the collars are based. The floor and ceiling prices related to the domestic collars are based on various regional first-of-the-month price indices as published monthly by *Inside FERC*.

OIL PRODUCTION

		2005 WEIGHTED AVERAGE		
AREA	BBLS/DAY	FLOOR PRICE PER BBL	CEILING PRICE PER BBL	MONTHS OF PRODUCTION
United States Onshore	3,000	$ 22.00	$ 28.25	Jan – Dec
United States Offshore	17,000	$ 22.00	$ 27.62	Jan – Dec
Canada	15,000	$ 22.00	$ 28.28	Jan – Dec
International	15,000	$ 23.50	$ 29.61	Jan – Dec

GAS PRODUCTION

		2005 WEIGHTED AVERAGE		
AREA	MMBTU/DAY	FLOOR PRICE PER MMBTU	CEILING PRICE PER MMBTU	MONTHS OF PRODUCTION
United States Onshore	40,000	$ 4.04	$ 7.00	Jan – Jun
United States Offshore	40,000	$ 3.50	$ 7.50	Jan – Dec
United States Offshore	70,000	$ 4.09	$ 7.00	Jan – Jun

Devon uses a sensitivity analysis technique to evaluate the hypothetical effect that changes in the market value of oil and gas may have on the fair value of its commodity hedging instruments. At December 31, 2004, a 10% increase in the underlying commodities' prices would have increased the net liabilities recorded for our commodity hedging instruments by $115 million.

Fixed-Price Physical Delivery Contracts In addition to the commodity hedging instruments described above, Devon also manages its exposure to oil and gas price risks by periodically entering into fixed-price contracts.

We have fixed-price physical delivery contracts for the years 2005 through 2011 covering Canadian natural gas production ranging from 8 Bcf to 14 Bcf per year. From 2012 through 2016, Devon also has Canadian gas volumes subject to fixed-price contracts, but the yearly volumes are less than 1 Bcf.

We also have fixed-price physical delivery contracts for the years 2005 through 2008 covering International natural gas production of 4 Bcf per year, except in 2008 when the volume drops to 3 Bcf.

Interest Rate Risk

At December 31, 2004, Devon had debt outstanding of $8.0 billion. Of this amount, $6.0 billion, or 75%, bears interest at fixed rates averaging 7.0%. Devon also has a floating-to-fixed interest rate swap in which we will record a fixed rate of 6.4% on a notional amount of $104 million in 2005 and 2006 and 6.3% on a notional amount of $32 million in 2007.

The remaining $1.8 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. The terms of Devon's Senior Credit Facility allow interest rates to be fixed at our option for periods of between seven to 180 days. As of December 31, 2004, there were no borrowings outstanding under the Senior Credit Facility. 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
7.625% senior notes due in 2005	$ 125	LIBOR plus 237 basis points
10.25% bonds due in 2005	$ 235	LIBOR plus 711 basis points
2.75% notes due in 2006	$ 500	LIBOR less 26.8 basis points
6.55% senior notes due 2006	$ 166 (1)	Banker's Acceptance plus 340 basis points
4.375% senior notes due in 2007	$ 400	LIBOR plus 40 basis points
6.75% senior notes due 2011	$ 400	LIBOR plus 197 basis points

(1) Converted from $200 million Canadian dollars at a Canadian-to-U.S. dollar exchange rate of $0.8308 as of December 31, 2004.

Devon uses a sensitivity analysis technique to evaluate the hypothetical effect that changes in interest rates may have on the fair value of its interest rate swap instruments. At December 31, 2004, a 10% increase in the underlying interest rates would have decreased the fair value of Devon's interest rate swaps by $28 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

Devon's net assets, net earnings and cash flows from its 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.

Our Canadian subsidiary, Devon Canada, has $400 million of fixed-rate long-term debt that is denominated in U.S. dollars. Changes in the currency conversion rate between the Canadian and U.S. dollars between the beginning and end of a reporting period increase or decrease the expected amount of Canadian dollars required to repay the notes. The amount of such increase or decrease is required to be included in determining net earnings for the period in which the exchange rate changes. A 10% decrease in the Canadian-to-U.S. dollar exchange rate would cause us to record a charge of approximately $40 million in 2005. The $400 million becomes due in March 2011. Until then, the gains or losses caused by the exchange rate fluctuations have no effect on cash flow.

Report of Independent Registered Public Accounting Firm

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, 2004 and 2003, 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, 2004. 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, 2004 and 2003, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2004, 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, 2004, 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 March 4, 2005 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

Oklahoma City, Oklahoma
March 4, 2005

Consolidated Balance Sheets

DECEMBER 31, (IN MILLIONS, EXCEPT SHARE DATA)		2004	2003
ASSETS:			
Current assets:			
Cash and cash equivalents	$	1,152	932
Short-term investments		967	341
Accounts receivable		1,320	946
Fair value of derivative financial instruments		1	13
Other current assets		143	132
Total current assets		3,583	2,364
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($3,187 and $3,336 excluded from amortization in 2004 and 2003, respectively)		32,114	28,546
Less accumulated depreciation, depletion and amortization		12,768	10,212
		19,346	18,334
Investment in ChevronTexaco Corporation common stock, at fair value		745	613
Fair value of derivative financial instruments		8	14
Goodwill		5,637	5,477
Other assets		417	360
Total assets	$	29,736	27,162
LIABILITIES AND STOCKHOLDERS' EQUITY:			
Current liabilities:			
Accounts payable:			
Trade	$	715	859
Revenues and royalties due to others		487	315
Income taxes payable		223	15
Current portion of long-term debt		933	338
Accrued interest payable		139	130
Fair value of derivative financial instruments		399	153
Current portion of asset retirement obligation		46	42
Accrued expenses and other current liabilities		158	219
Total current liabilities		3,100	2,071
Debentures exchangeable into shares of ChevronTexaco Corporation common stock		692	677
Other long-term debt		6,339	7,903
Preferred stock of a subsidiary		—	55
Fair value of derivative financial instruments		72	52
Asset retirement obligation, long-term		693	629
Other liabilities		366	349
Deferred income taxes		4,800	4,370
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 $.10 par value. Authorized 800,000,000 shares; issued 483,909,000 in 2004 and 479,534,000 in 2003		48	47
Additional paid-in capital		9,087	9,043
Retained earnings		3,693	1,614
Accumulated other comprehensive income		930	569
Deferred compensation and other		(85)	(32)
Treasury stock, at cost: none in 2004 and 7,354,000 shares in 2003		—	(186)
Total stockholders' equity		13,674	11,056
Commitments and contingencies (Note 14)			
Total liabilities and stockholders' equity	$	29,736	27,162

See accompanying notes to consolidated financial statements

Consolidated Statements of Operations

YEAR ENDED DECEMBER 31, (IN MILLIONS, EXCEPT PER SHARE AMOUNTS)		2004	2003	2002
REVENUES:				
Oil sales	$	2,202	1,588	909
Gas sales		4,732	3,897	2,133
NGL sales		554	407	275
Marketing and midstream revenues		1,701	1,460	999
Total revenues		9,189	7,352	4,316
OPERATING COSTS AND EXPENSES:				
Lease operating expenses		1,280	1,078	775
Production taxes		255	204	111
Marketing and midstream operating costs and expenses		1,339	1,174	808
Depreciation, depletion and amortization of oil and gas properties		2,141	1,668	1,106
Depreciation and amortization of non-oil and gas properties		149	125	105
Accretion of asset retirement obligation		44	36	—
General and administrative expenses		277	307	219
Expenses related to mergers		—	7	—
Reduction of carrying value of oil and gas properties		—	111	651
Total operating costs and expenses		5,485	4,710	3,775
Earnings from operations		3,704	2,642	541
OTHER INCOME (EXPENSES):				
Interest expense		(475)	(502)	(533)
Dividends on subsidiary's preferred stock		—	(2)	—
Effects of changes in foreign currency exchange rates		23	69	1
Change in fair value of derivative financial instruments		(62)	1	28
Impairment of ChevronTexaco Corporation common stock		—	—	(205)
Other income		103	37	34
Net other expenses		(411)	(397)	(675)
Earnings (loss) from continuing operations before income taxes and cumulative effect of change in accounting principle		3,293	2,245	(134)
INCOME TAX EXPENSE (BENEFIT):				
Current		752	193	23
Deferred		355	321	(216)
Total income tax expense (benefit)		1,107	514	(193)
Earnings from continuing operations before cumulative effect of change in accounting principle		2,186	1,731	59
DISCONTINUED OPERATIONS:				
Results of discontinued operations before income taxes (including net gain on disposal of $31 million in 2002)		—	—	54
Income tax expense		—	—	9
Net results of discontinued operations		—	—	45
Earnings before cumulative effect of change in accounting principle		2,186	1,731	104
Cumulative effect of change in accounting principle, net of tax		—	16	—
Net earnings		2,186	1,747	104
Preferred stock dividends		10	10	10
Net earnings applicable to common stockholders	$	2,176	1,737	94
Basic net earnings per share:				
Earnings from continuing operations	$	4.51	4.12	0.16
Net results of discontinued operations		—	—	0.15
Cumulative effect of change in accounting principle, net of tax		—	0.04	—
Net earnings	$	4.51	4.16	0.31
Diluted net earnings per share:				
Earnings from continuing operations	$	4.38	4.00	0.16
Net results of discontinued operations		—	—	0.14
Cumulative effect of change in accounting principle, net of tax		—	0.04	—
Net earnings	$	4.38	4.04	0.30
Weighted average common shares outstanding:				
Basic		482	417	309
Diluted		499	433	313

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 COMPRE-HENSIVE INCOME (LOSS)	DEFERRED COMPEN-SATION AND OTHER	TREASURY STOCK	TOTAL STOCK-HOLDERS' EQUITY
BALANCE AS OF DECEMBER 31, 2001	$ 1	25	3,598	(147)	(28)	—	(190)	3,259
Comprehensive loss:								
Net earnings	—	—	—	104	—	—	—	104
Other comprehensive income (loss), net of tax:								
Foreign currency translation adjustments	—	—	—	—	46	—	—	46
Reclassification adjustment for derivative gains reclassified into oil and gas sales	—	—	—	—	(39)	—	—	(39)
Change in fair value of derivative financial instruments	—	—	—	—	(217)	—	—	(217)
Minimum pension liability adjustment	—	—	—	—	(54)	—	—	(54)
Unrealized loss on marketable securities	—	—	—	—	(103)	—	—	(103)
Impairment of marketable securities	—	—	—	—	128	—	—	128
Other comprehensive loss								(239)
Comprehensive loss								(135)
Stock issued	—	6	1,556	—	—	—	2	1,564
Tax benefit related to employee stock options	—	—	6	—	—	—	—	6
Dividends on common stock	—	—	—	(31)	—	—	—	(31)
Dividends on preferred stock	—	—	—	(10)	—	—	—	(10)
Grant of restricted stock awards	—	—	3	—	—	(3)	—	—
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	—	14	3,817	—	—	—	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	—	2	32	—	—	(34)	—	—
Amortization of restricted stock awards	—	—	—	—	—	2	—	2
Other	—	—	—	—	—	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	—	—	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

See accompanying notes to consolidated financial statements

Consolidated Statements of Cash Flows

YEAR ENDED DECEMBER 31, (IN MILLIONS)		2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES:				
Earnings from continuing operations	$	2,186	1,731	59
Adjustments to reconcile earnings from continuing operations to net cash provided by operating activities:				
Depreciation, depletion and amortization		2,290	1,793	1,211
Accretion of asset retirement obligation		44	36	—
Accretion of discounts on long-term debt, net		11	19	33
Effects of changes in foreign currency exchange rates		(23)	(69)	(1)
Change in fair value of derivative financial instruments		62	(1)	(28)
Reduction of carrying value of oil and gas properties		—	111	651
Impairment of ChevronTexaco Corporation common stock		—	—	205
Operating cash flows from discontinued operations		—	—	28
(Gain) loss on sale of assets		(34)	7	(2)
Deferred income tax expense (benefit)		355	321	(216)
Other		31	(48)	(9)
Changes in assets and liabilities, net of effects of acquisitions of businesses:				
(Increase) decrease in:				
Accounts receivable		(345)	(164)	(80)
Other current assets		(20)	(34)	22
Long-term other assets		(91)	—	—
Increase (decrease) in:				
Accounts payable		190	42	(74)
Income taxes payable		208	62	21
Accrued interest and expenses		(79)	(2)	(10)
Long-term other liabilities		31	(36)	(56)
Net cash provided by operating activities		4,816	3,768	1,754
CASH FLOWS FROM INVESTING ACTIVITIES:				
Proceeds from sale of property and equipment		95	179	1,067
Capital expenditures, including acquisitions of businesses		(3,103)	(2,587)	(3,426)
Purchases of short-term investments		(3,215)	(702)	—
Sales of short-term investments		2,589	361	—
Discontinued operations (including net proceeds from sale of $336 million in 2002)		—	—	316
Other		—	(24)	(3)
Net cash used in investing activities		(3,634)	(2,773)	(2,046)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from borrowings of long-term debt, net of issuance costs		—	597	6,067
Principal payments on long-term debt		(973)	(1,118)	(5,657)
Issuance of common stock, net of issuance costs		268	155	32
Repurchase of common stock		(189)	—	—
Dividends paid on common stock		(97)	(39)	(31)
Dividends paid on preferred stock		(10)	(10)	(10)
Increase in long-term other liabilities		—	1	—
Net cash (used in) provided by financing activities		(1,001)	(414)	401
Effect of exchange rate changes on cash		39	59	—
Net increase in cash and cash equivalents		220	640	109
Cash and cash equivalents at beginning of year		932	292	183
Cash and cash equivalents at end of year	$	1,152	932	292

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, and Devon's international activities—outside of North America—are located primarily in Azerbaijan, China, Egypt, 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. 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. Actual amounts could differ from those estimates.

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 obligations, 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 previously estimated costs of dismantlement, removal, site reclamation, and other similar activities in the total costs that are 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.

Assuming the provisions of SFAS No. 143 had been adopted as of January 1, 2002, Devon's 2002 net earnings would have been $5 million less than the reported 2002 net earnings. This would have also resulted in a $0.02 and $0.01 reduction to 2002 basic and diluted net earnings applicable to common stockholders, respectively.

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 did not materially impact the full cost ceiling test calculation or depletion for 2004.

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, 2004 and 2003, Devon's short-term investments consisted of $967 million and $341 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 7 to 49 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. The 2003 balance of such securities was previously classified as cash equivalents due to the liquidity and pricing reset feature. In 2004, these securities were reclassified as short-term investments to conform to current year presentation. There was no impact on net earnings or cash flow from operations as a result on the reclassification.

Devon's only other significant investment security is its investment in approximately 14.2 million shares of ChevronTexaco Corporation ("ChevronTexaco") 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 ChevronTexaco 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 2004, 2003 and 2002. 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, 2004 and 2003:

	DECEMBER 31, 2004	2003
	(IN MILLIONS)	
United States	$ 3,061	3,073
Canada	2,508	2,336
International	68	68
Total	$ 5,637	5,477

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 underproduced 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 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 2004, 2003 and 2002.

Derivative Instruments

Devon enters 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.

All derivatives are recognized as fair value of financial instruments on the consolidated balance sheets at their fair value. A substantial portion of Devon's derivatives consists of contracts that hedge the price of future oil and natural gas production. These derivative contracts are cash flow hedges that qualify 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.

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 treatment or the hedged transaction is no longer likely to occur, the changes in fair value of these hedging instruments would not be recorded directly to equity but in the consolidated results of operations. During 2004, 2003 and 2002, there were no gains or losses reclassified into earnings as a result of the discontinuance of hedge accounting treatment for any of Devon's derivatives.

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. Devon's commodity costless price collars and price swaps have been designated as cash flow hedges. Changes in the fair value of these derivatives are reported on the balance sheet in accumulated other comprehensive income. These amounts are reclassified to oil and gas sales when the forecasted transaction takes place.

During 2004, 2003 and 2002, Devon recorded in its statements of operations a loss of $62 million, a gain of $1 million and a gain of $28 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.

As of December 31, 2004, $395 million of net deferred losses on derivative instruments accumulated in accumulated other comprehensive income are expected to be reclassified to oil and gas sales during the next 12 months assuming no change in the forward commodity prices from the December 31, 2004 forward prices. Transactions and events expected to occur over the next 12 months that will necessitate reclassifying these derivatives' losses to earnings are primarily the production and sale of oil and natural gas which includes the production hedged under the various derivative instruments. Presently, the maximum term over which Devon has hedged exposures to the variability of cash flows for commodity price risk under its various derivative instruments is 12 months.

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 for prior years 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 2004, 2003 and 2002 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,		
		2004	2003	2002
		(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)		
Net earnings available to common stockholders, as reported	$	2,176	1,737	94
Add stock-based employee compensation expense included in reported net earnings, net of related tax expense		7	2	1
Deduct total stock-based employee compensation expense determined under fair value based method for all awards (see Note 11), net of related tax expense		(31)	(23)	(17)
Net earnings available to common stockholders, pro forma	$	2,152	1,716	78
Net earnings per share available to common stockholders:				
As reported:				
Basic	$	4.51	4.16	0.31
Diluted	$	4.38	4.04	0.30
Pro forma:				
Basic	$	4.46	4.11	0.25
Diluted	$	4.33	3.99	0.25

The weighted average fair values of stock options granted during 2004, 2003 and 2002 were $10.32, $8.14 and $7.63, 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 2004, 2003 and 2002, respectively: risk-free interest rates of 3.2%, 2.8% and 3.2%; dividend yields of 0.5%, 0.4% and 0.4%; expected lives of four, four and five years; and volatility of the price of the underlying common stock of 32.2%, 37.9% and 41.8%.

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. For 2004, 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, 2004.

In October 2004, Congress enacted new tax legislation allowing qualifying corporations to repatriate cash from foreign operations at a reduced income tax rate. 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. In the first quarter of 2005, Devon's board of directors approved the repatriation of $500 million of earnings from Canadian operations which will be taxed at the reduced income tax rate. As a result, Devon will recognize, in the first quarter of 2005, approximately $30 million of additional current income tax expense (which would have been the same approximate amount recognized in 2004 if Devon had finalized its repatriation plans prior to 2005).

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 preferred stock of a subsidiary were converted to common stock and if Devon's 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 2004, 2003 and 2002.

	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, 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
YEAR ENDED DECEMBER 31, 2002:			
Basic earnings per share	$ 94	309	$ 0.31
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	4	
Diluted earnings per share	$ 94	313	$ 0.30

The senior convertible debentures included in the 2004 and 2003 dilution calculations were not included in the 2002 dilution calculation because the effect of inclusion was anti-dilutive.

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.

	2004	2003	2002
Options excluded from dilution calculation (in millions)	4	10	11
Range of exercise prices	$33.00 – $44.83	$24.96 – $44.83	$22.75 – $44.83
Weighted average exercise price	$ 38.22	$ 28.05	$ 25.42

The excluded options for 2004 expire between January 9, 2007 and December 8, 2012.

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 14 for a discussion of amounts recorded for these liabilities.

Reclassifications

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

Impact of 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 third quarter of 2005 and anticipates adopting SFAS No. 123(R) using the modified prospective method. Under this method, Devon will recognize compensation expense for all stock-based awards granted or modified on or after July 1, 2005, as well as, any previously granted awards that are not fully vested as of July 1, 2005. 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. Devon is currently assessing the impact of adopting SFAS No. 123(R) on consolidated results of operations. However, Devon does not expect such impact to be material upon adoption in the third quarter of 2005.

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 and Devon's January 24, 2002 merger with Mitchell Energy & Development Corp. were consummated on January 1, 2002. 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, 2002. The pro forma information also should not be used as an indication of the future results that Devon will achieve after the transactions.

	PRO FORMA INFORMATION YEAR ENDED DECEMBER 31,	
	2003	2002
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS AND PRODUCTION VOLUMES) (UNAUDITED)	
REVENUES:		
Oil sales	$ 1,840	1,549
Gas sales	4,155	2,655
NGL sales	416	304
Marketing and midstream revenues	1,461	1,069
Total revenues	7,872	5,577
OPERATING COSTS AND EXPENSES:		
Lease operating expenses	1,167	1,025
Production taxes	219	148
Marketing and midstream operating costs and expenses	1,174	873
Depreciation, depletion and amortization of oil and gas properties	1,859	1,740
Depreciation and amortization of non-oil and gas properties	125	122
Accretion of asset retirement obligation	38	—
General and administrative expenses	340	321
Reduction of carrying value of oil and gas properties	111	727
Total operating costs and expenses	5,033	4,956
Earnings from operations	2,839	621
OTHER INCOME (EXPENSES):		
Interest expense	(515)	(582)
Dividends on subsidiary's preferred stock	(3)	(3)
Effects of changes in foreign currency exchange rates	69	1
Change in fair value of financial instruments	1	28
Impairment of ChevronTexaco Corporation common stock	—	(205)
Other income	40	32
Net other expenses	(408)	(729)
Earnings (loss) before income taxes and cumulative effect of change in accounting principle	2,431	(108)
INCOME TAX EXPENSE (BENEFIT):		
Current	219	47
Deferred	372	(199)
Total income tax expense (benefit)	591	(152)
Earnings from continuing operations before cumulative effect of change in accounting principle	1,840	44
DISCONTINUED OPERATIONS:		
Results of discontinued operations before income taxes (including net gain on disposal of $31 million in 2002)	—	54
Total income tax expense	—	9
Net results of discontinued operations	—	45
Earnings before cumulative effect of change in accounting principle	1,840	89
Cumulative effect of change in accounting principle	29	—
Net earnings	1,869	89
Preferred stock dividends	10	10
Net earnings applicable to common stockholders	$ 1,859	79

	PRO FORMA INFORMATION YEAR ENDED DECEMBER 31, 2003	2002
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS AND PRODUCTION VOLUMES) (UNAUDITED)	
Basic earnings per average common share outstanding:		
Earnings from continuing operations	$ 3.95	0.08
Net results of discontinued operations	—	0.10
Cumulative effect of change in accounting principle	0.06	—
Net earnings	$ 4.01	0.18
Diluted earnings per average common share outstanding:		
Earnings from continuing operations	$ 3.83	0.07
Net results of discontinued operations	—	0.10
Cumulative effect of change in accounting principle	0.06	—
Net earnings	$ 3.89	0.17
Weighted average common shares outstanding — basic	463	458
Weighted average common shares outstanding — diluted	481	472
Production volumes:		
Oil (MMBbls)	72	70
Gas (Bcf)	913	927
NGLs (MMBbls)	23	22
MMBoe	247	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, 2004, 2003 and 2002, and changes during each of the years then ended, is presented in the following table.

	FOREIGN CURRENCY TRANSLATION ADJUSTMENTS	CHANGE IN FAIR VALUE OF FINANCIAL INSTRUMENTS	MINIMUM PENSION LIABILITY ADJUSTMENTS	UNREALIZED GAIN (LOSS) ON MARKETABLE SECURITIES	TOTAL
			(IN MILLIONS)		
BALANCE AS OF DECEMBER 31, 2001	$ (145)	159	(17)	(25)	(28)
2002 activity	46	(379)	(85)	41	(377)
Deferred taxes	—	123	31	(16)	138
2002 activity, net of deferred taxes	46	(256)	(54)	25	(239)
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

The 2002 activity for unrealized gain (loss) on marketable securities includes unrealized losses of $164 million ($103 million net of taxes), offset by the recognition of a $205 million loss ($128 million net of taxes) in the statement of operations during 2002. The recognized loss was due to the impairment of the ChevronTexaco common stock owned by Devon.

4 SUPPLEMENTAL CASH FLOW INFORMATION

Cash payments (refunds) for interest and income taxes in 2004, 2003 and 2002 are presented below:

	YEAR ENDED DECEMBER 31, 2004	2003	2002
	(IN MILLIONS)		
Interest paid	$ 474	508	248
Income taxes paid (refunded)	$ 477	123	(12)

The 2003 Ocean merger and 2002 Mitchell merger involved non-cash consideration as presented below:

	OCEAN MERGER	MITCHELL MERGER
	(IN MILLIONS)	
Value of common stock issued	$ 3,546	1,512
Convertible preferred stock assumed	64	—
Employee stock options assumed	124	27
Liabilities assumed	2,393	824
Deferred tax liability created	954	798
Fair value of assets acquired with non-cash consideration	$ 7,081	3,161

5 ACCOUNTS RECEIVABLE

The components of accounts receivable included the following:

	DECEMBER 31, 2004	2003
	(IN MILLIONS)	
Oil, gas and natural gas liquids revenue accruals	$ 946	668
Joint interest billings	159	124
Marketing and midstream revenue accruals	162	106
Other	60	59
	1,327	957
Allowance for doubtful accounts	(7)	(11)
Net accounts receivable	$ 1,320	946

6 PROPERTY AND EQUIPMENT AND ASSET RETIREMENT OBLIGATIONS

Property and equipment included the following:

	DECEMBER 31, 2004	2003
	(IN MILLIONS)	
Oil and gas properties:		
Subject to amortization	$ 27,257	23,590
Not subject to amortization	3,187	3,336
Accumulated depreciation, depletion and amortization	(12,410)	(9,967)
Net oil and gas properties	18,034	16,959
Other property and equipment	1,670	1,620
Accumulated depreciation and amortization	(358)	(245)
Net other property and equipment	1,312	1,375
Property and equipment, net of accumulated depreciation, depletion and amortization	$ 19,346	18,334

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 at least annually. 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, 2004:

		COSTS INCURRED IN				
		2004	2003	2002	PRIOR TO 2002	Total
				(IN MILLIONS)		
Acquisition costs	$	174	674	471	1,086	2,405
Exploration costs		279	246	47	6	578
Development costs		32	61	4	—	97
Capitalized interest		66	37	2	2	107
Total oil and gas properties costs not subject to amortization	$	551	1,018	524	1,094	3,187

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, 2004 and 2003.

		YEAR ENDED DECEMBER 31,	
		2004	2003
		(IN MILLIONS)	
Asset retirement obligation as of beginning of year	$	671	—
Cumulative effect of change in accounting principle		—	453
Asset retirement obligation assumed from Ocean merger		—	134
Liabilities incurred		51	48
Liabilities settled		(42)	(37)
Liabilities assumed by others		(4)	(4)
Accretion expense on discounted obligation		44	36
Foreign currency translation adjustment		19	41
Asset retirement obligation as of end of year		739	671
Less current portion		46	42
Asset retirement obligation, long-term	$	693	629

7 INVESTMENT IN CHEVRONTEXACO CORPORATION COMMON STOCK

In the fourth quarter of 2002, Devon recorded a $205 million other-than-temporary impairment of its investment in 14.2 million shares of ChevronTexaco common stock. Devon acquired these shares in its August 1999 acquisition of PennzEnergy Company. The shares are deposited with an exchange agent for possible exchange for $760 million of debentures that are exchangeable into the ChevronTexaco shares. The debentures, which mature in August 2008, were also assumed by Devon in the 1999 PennzEnergy acquisition.

At the closing date of the PennzEnergy acquisition, Devon initially recorded the ChevronTexaco common shares at their fair value, which was $47.69 per share, or an aggregate value of $677 million. Since then, as the ChevronTexaco shares have fluctuated in market value, the value of the shares on Devon's balance sheet has been adjusted to the applicable market value. Through September 30, 2002, any decreases in the value of the ChevronTexaco common shares were determined by Devon to be temporary in nature. Therefore, the changes in value were recorded directly to stockholders' equity and were not recorded in Devon's results of operations through September 30, 2002.

The determination that a decline in value of the ChevronTexaco shares is temporary or other than temporary is subjective and influenced by many factors. Among these factors are the significance of the decline as a percentage of the original cost, the length of time the stock price has been below original cost, the performance of the stock price in relation to the stock price of its competitors within the industry and the market in general, and whether the decline is attributable to specific adverse conditions affecting ChevronTexaco.

Beginning in July 2002, the market value of ChevronTexaco common stock began a significant decline. The price per share decreased from $44.25 at June 30, 2002, to $34.63 per share at September 30, 2002, and to $33.24 per share at December 31, 2002. The 2002 year-end price of $33.24 represented a 25% decline since June 30, 2002, and a 30% decline from the original valuation in August 1999. As a result of the decline in value during the fourth quarter of 2002, Devon determined that the decline was other than temporary, as that term is defined by accounting rules. Therefore, the $205 million cumulative decrease in the value of the ChevronTexaco common shares from the initial acquisition in August 1999 to December 31, 2002, was recorded as a noncash charge to Devon's results of operations in the fourth quarter of 2002. Net of the applicable tax benefit, the charge reduced net earnings by $128 million.

The share price of ChevronTexaco common stock has increased to $43.19 at December 31, 2003 and $52.51 at December 31, 2004. As a result, the market value of Devon's investment in ChevronTexaco common stock increased $273 million from December 31, 2002 to December 31, 2004. The changes in the value of the shares since December 31, 2002, net of applicable taxes, have been recorded directly to accumulated other comprehensive income in stockholders' equity. However, depending on the future performance of ChevronTexaco's common stock, Devon may be required to record additional noncash charges in future periods if the value of such stock declines, and Devon determines that such declines are other than temporary.

8 LONG-TERM DEBT AND RELATED EXPENSES

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

	DECEMBER 31, 2004	2003
	(IN MILLIONS)	
Borrowings under credit facilities with banks	$ —	—
Commercial paper borrowings	—	—
$3 billion term loan credit facility due October 15, 2006 (retired in 2004)	—	635
Debentures exchangeable into shares of ChevronTexaco Corporation common stock:		
4.90% due August 15, 2008	444	444
4.95% due August 15, 2008	316	316
Discount on exchangeable debentures	(68)	(83)
Zero coupon convertible senior debentures exchangeable into shares of Devon common stock, due June 27, 2020 (first put date June 26, 2005)	419	404
Other debentures and notes:		
6.75% due February 15, 2004	—	211
8.05% due June 15, 2004	—	125
7.625% due July 1, 2005	125	125
7.25% due July 18, 2005 ($175 million Canadian)	145	135
10.25% due November 1, 2005	236	236
2.75% due August 1, 2006	500	500
6.55% due August 2, 2006 ($200 million Canadian)	166	155
4.375% due October 1, 2007	400	400
10.125% due November 15, 2009	177	177
6.75% due March 15, 2011	400	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	4
Fair value adjustment on debt related to interest rate swaps	9	27
Net premium on other debentures and notes	67	82
	7,964	8,918
Less amount classified as current	933	338
Long-term debt	$ 7,031	8,580

Maturities of long-term debt as of December 31, 2004, excluding the $1 million of net discounts and the $9 million fair value adjustment, are as follows (in millions):

2005	$ 926
2006	667
2007	400
2008	761
2009	177
2010 and thereafter	5,025
Total	$ 7,956

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, 2009, 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 has obtained lender approval to extend the current maturity date of April 8, 2009 to April 8, 2010. This maturity date extension will be effective April 8, 2005 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, 2004, Devon was in compliance with such covenants and restrictions. Devon's debt-to-capitalization ratio at December 31, 2004, as calculated pursuant to the terms of the agreement, was 33.0%.

As of December 31, 2004, there were no borrowings under the Senior Credit Facility. The available capacity under the Senior Credit Facility as of December 31, 2004, net of $226 million of outstanding letters of credit, was approximately $1.3 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, 2004 and 2003, 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, 2004, the call price was 102.0% 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 ChevronTexaco common stock. In lieu of delivering ChevronTexaco 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 ChevronTexaco 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, 2004, Devon beneficially owned approximately 14.2 million shares of ChevronTexaco 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 ChevronTexaco common stock, an exchange rate equivalent to $53.60 per share of ChevronTexaco 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 ChevronTexaco 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 2000, Devon privately sold zero coupon convertible senior debentures. The debentures were sold at a price of $464.13 per debenture with a yield to maturity of 3.875% per annum. Each of the 760,000 debentures is convertible into 11.5186 shares of Devon common stock. Devon may call the debentures at any time after five years, and a debenture holder has the right to require Devon to repurchase the debentures after five, 10 and 15 years, at the issue price plus accrued original issue discount and interest. The first put date is June 26, 2005, at an accreted value of $427 million. Therefore, Devon has classified these debentures as current liabilities in the December 31, 2004 consolidated balance sheet. Devon has the right to satisfy its obligation by paying cash or issuing shares of Devon common stock with a value equal to its obligation. Devon's proceeds were approximately $346 million, net of debt issuance costs of approximately $7 million. Devon used the proceeds from the sale of these debentures to pay down other domestic long-term debt.

Other Debentures and Notes

Following are descriptions of the various other debentures and notes outstanding at December 31, 2004, 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 and discounts are being amortized or accreted using the effective interest method. All of the notes are general unsecured obligations of Devon.

DEBT ASSUMED	FAIR VALUE OF DEBT ASSUMED	EFFECTIVE RATE OF DEBT ASSUMED
	(IN MILLIONS)	
7.625% due July 2005 (principal of $125 million)	$ 139	3.0%
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 premiums and discounts are being amortized or accreted using the effective interest method. All of the notes are general unsecured obligations of Devon.

DEBT ASSUMED	FAIR VALUE OF DEBT ASSUMED	EFFECTIVE RATE OF DEBT ASSUMED
	(IN MILLIONS)	
7.25% senior notes due 2005	$ 116	6.3%
6.55% senior notes due 2006	$ 129	6.5%
6.75% senior notes due 2011	$ 400	6.8%

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 the $3 billion term loan credit facility.

10.25% Debentures due November 1, 2005 and 10.125% Debentures due November 15, 2009 These debentures were assumed as part of the PennzEnergy acquisition. The fair values of the respective debentures were determined using August 17, 1999, market interest rates. As a result, premiums were recorded on these debentures which lowered their effective interest rates to 8.3% and 8.9% on the $236 million of 10.25% debentures and $177 million of 10.125% debentures, respectively. The premiums are 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. The notes were redeemed at 104.375% of principal, or approximately $183 million.

Interest Expense

Following are the components of interest expense for the years 2004, 2003 and 2002:

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
		(IN MILLIONS)	
Interest based on debt outstanding	$ 513	531	499
Accretion of debt discount, net	2	3	13
Facility and agency fees	2	1	2
Amortization of capitalized loan costs	22	12	8
Capitalized interest	(70)	(50)	(4)
Early retirement premiums	—	—	8
Other	6	5	7
Total interest expense	$ 475	502	533

Effects of Changes in Foreign Currency Exchange Rates

The $400 million of 6.75% fixed-rate senior notes referred to in the first table of this note are payable by a Canadian subsidiary of Devon. However, the notes are 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 increase or decrease 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. As a result of changes in the rate of conversion of Canadian dollars to U.S. dollars, $22 million, $69 million and $1 million was recorded as a reduction of expense in 2004, 2003 and 2002, respectively.

9 INCOME TAXES

At December 31, 2004, 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	2020 – 2022	$ 383
Various U.S. states	2005 – 2022	$ 265
Canada	2006 – 2014	$ 524
Azerbaijan	Indefinite	$ 75

Additionally, at December 31, 2004, Devon had $29 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 deferred tax liability at December 31, 2004.

The earnings (loss) before income taxes and the components of income tax expense (benefit) for the years 2004, 2003 and 2002 were as follows:

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
		(IN MILLIONS)	
Earnings (loss) from continuing operations before income taxes:			
U.S	$ 2,264	1,603	354
Canada	598	603	(515)
International	431	39	27
Total	$ 3,293	2,245	(134)
Current income tax expense (benefit):			
U.S. federal	$ 473	125	(34)
Various states	10	6	11
Canada	49	(9)	28
International	220	71	18
Total current tax expense	752	193	23
Deferred income tax expense (benefit):			
U.S. federal	219	360	56
Various states	21	17	(14)
Canada	149	(16)	(253)
International	(34)	(40)	(5)
Total deferred tax expense (benefit)	355	321	(216)
Total income tax expense (benefit)	$ 1,107	514	(193)

The taxes on the results of discontinued operations presented in the accompanying statements of operations were all related to foreign operations.

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

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
		(IN MILLIONS)	
Expected income tax expense (benefit) based on U.S. statutory tax rate of 35%	$ 1,153	786	(47)
Financial expenses not deductible for income tax purposes	2	1	—
Dividends received deduction	(5)	(5)	(5)
Nonconventional fuel source credits	—	—	(19)
State income taxes	20	15	7
Taxation on foreign operations	(30)	(78)	(121)
Effect of Canadian tax rate reductions	(36)	(218)	—
Other	3	13	(8)
Total income tax expense (benefit)	$ 1,107	514	(193)

During 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 a $36 million and $218 million benefit being recorded in 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, 2004 and 2003 are presented below:

		DECEMBER 31, 2004	DECEMBER 31, 2003
		(IN MILLIONS)	
Deferred tax assets:			
Net operating loss carryforwards	$	336	416
Minimum tax credit carryforwards		29	56
Fair value of financial instruments		157	44
Asset retirement obligations		252	281
Pension benefit obligation		52	85
Other		130	139
Total deferred tax assets		956	1,021
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		(5,366)	(5,052)
ChevronTexaco Corporation common stock		(231)	(190)
Long-term debt		(149)	(102)
Other		(10)	(47)
Total deferred tax liabilities		(5,756)	(5,391)
Net deferred tax liability	$	(4,800)	(4,370)

As shown in the above table, Devon has recognized $956 million of deferred tax assets as of December 31, 2004. Such amount consists of $336 million of various carryforwards available to offset future income taxes. The carryforwards include federal net operating loss carryforwards, the majority of which do not begin to expire until 2020, state net operating loss carryforwards which expire primarily between 2005 and 2022, Canadian net operating loss carryforwards which expire primarily between 2006 and 2014, 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 2005 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.

10 PREFERRED STOCK OF A SUBSIDIARY

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.

11 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.

There were 32 million exchangeable shares issued on December 10, 1998, in connection with the Northstar Energy Corporation combination. These shares were essentially equivalent to Devon common stock and were exchangeable at any time, on a one-for-one basis, for common shares of Devon at the holder's option. The last remaining exchangeable shares outstanding were exchanged for Devon common stock on August 27, 2004.

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, 2004, 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.

On September 27, 2004, Devon announced a stock buyback 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. Devon intends to continue repurchasing its shares in the open market and in privately negotiated transactions, depending upon market conditions. The stock repurchase program may be discontinued at any time.

The following is a summary of the changes in Devon's common shares outstanding for 2004, 2003 and 2002:

	2004	2003	2002
		(IN MILLIONS)	
Shares outstanding, beginning of year	472	314	252
Exercise of stock options	13	10	2
Shares repurchased and retired	(5)	—	—
Grant of restricted stock	2	—	—
Conversion of subsidiary's preferred stock	2	—	—
Issuance of common stock	—	148	60
Shares outstanding, end of year	484	472	314

Stock Option Plans

Devon has outstanding stock options issued to key management and professional employees under three stock option plans adopted in 1993, 1997 and 2003 (the "1993 Plan," the "1997 Plan" and the "2003 Plan"). Options granted under the 1993 Plan and 1997 Plan remain exercisable by the employees owning such options, but no new options will be granted under these plans. At December 31, 2004, there were 202,000 and 8,774,000 options outstanding under the 1993 Plan and the 1997 Plan, respectively.

On April 25, 2003, Devon's stockholders adopted the 2003 Long-Term Incentive Plan. The new long-term incentive plan authorizes the compensation committee of Devon's board of directors to grant nonqualified and incentive stock options, stock appreciation rights, restricted stock awards, 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 25,000,000 shares of Devon common stock have been reserved for issuance pursuant to the plan. Of these shares, no more than 5,000,000 shares may be granted as restricted stock, performance bonuses and performance units. During 2004 and 2003, 1,703,000 and 1,306,000 restricted stock awards, respectively, were granted which are subject to pro rata vesting over a four-year period. These awards had an aggregate fair value of $66 million and $34 million in 2004 and 2003, respectively, and will be recorded as compensation expense over the vesting period.

The exercise price of stock options granted under the 2003 Plan may not be less than the estimated fair market value of the stock at the date of grant. Options granted are exercisable during a period established for each grant, which period may not exceed eight years from the date of grant. Under the 2003 Plan, 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. The 2003 Plan is administered by a committee comprised of non-management members of the board of directors. The 2003 Plan expires on April 25, 2013. As of December 31, 2004, there were 5,906,000 options outstanding under the 2003 Plan. There were 16,022,000 options available for future grants as of December 31, 2004.

In addition to the stock options outstanding under the 1993 Plan, 1997 Plan and 2003 Plan there were approximately 2,739,000, 363,000, 200,000 and 1,591,000 stock options outstanding at the end of 2004 that were assumed as part of the Ocean merger, the Mitchell merger, the Santa Fe Snyder merger and the PennzEnergy merger, respectively.

A summary of the status of Devon's stock option plans as of December 31, 2002, 2003 and 2004, 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, 2001	16,368	$ 20.54	11,032	$ 20.97
Options granted	5,614	$ 22.88		
Options assumed in the Mitchell merger	3,108	$ 13.41		
Options exercised	(1,799)	$ 14.67		
Options forfeited	(830)	$ 23.56		
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

The following table summarizes information about Devon's stock options which were outstanding, and those which were exercisable, as of December 31, 2004:

	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
$4.84 - $17.43	3,765	4.63 Years	$ 15.75	3,316	$ 15.52
$17.90 - $23.04	2,158	4.64 Years	$ 20.68	2,108	$ 20.68
$23.05 - $23.05	3,784	5.94 Years	$ 23.05	2,170	$ 23.05
$23.14 - $26.43	4,829	5.24 Years	$ 25.95	3,090	$ 25.73
$26.50 - $38.45	4,922	4.82 Years	$ 35.70	2,040	$ 32.43
$38.61 - $44.83	317	2.88 Years	$ 40.86	303	$ 40.89
	19,775	5.05 Years	$ 25.54	13,027	$ 23.27

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 $.01 per right until the rights become exercisable.

Dividends

Dividends on Devon's common stock were paid in 2004 at a per share rate of $0.05 per quarter. Dividends on Devon's common stock were paid in 2003 and 2002 at a per share rate of $0.025 per quarter.

12 FINANCIAL INSTRUMENTS

The following table presents the carrying amounts and estimated fair values of Devon's financial instrument assets (liabilities) at December 31, 2004 and 2003.

		2004		2003	
		CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
		(IN MILLIONS)			
Investment in ChevronTexaco Corporation common stock	$	745	745	613	613
Oil and gas price hedge agreements	$	(395)	(395)	(186)	(186)
Interest rate swap agreements	$	—	—	18	18
Electricity hedge agreements	$	—	—	(1)	(1)
Embedded option in exchangeable debentures	$	(67)	(67)	(9)	(9)
Long-term debt	$	(7,964)	(9,046)	(8,918)	(9,680)
Preferred stock of a subsidiary	$	—	—	(55)	(63)

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, 2004 and 2003.

Investment in ChevronTexaco 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 are 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.

Electricity Hedge Agreements — The fair values of the electricity hedges are based on internal discounted cash flow calculations.

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

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.

Preferred Stock of a Subsidiary — The fair value of the preferred stock is based upon quotes obtained from brokers.

Devon's total hedged positions as of December 31, 2004 are set forth in the following tables.

Price Swaps

Through various price swaps, Devon has fixed the price it will receive on a portion of its oil and natural gas production in 2005. These swaps will result in the fixed prices included below. Where necessary, the oil and gas prices related to these swaps have been adjusted for certain transportation costs that are netted against the price recorded by Devon, and the gas price has also been adjusted for the Btu content of the production that has been hedged.

OIL PRODUCTION		
YEAR	BBLS/DAY	WEIGHTED AVERAGE PRICE PER BBL
2005	22,000	$ 26.84

GAS PRODUCTION		
YEAR	MCF/DAY	WEIGHTED AVERAGE PRICE PER MCF
2005	7,343	$ 3.40

Costless Price Collars

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2005 oil production that is otherwise subject to floating prices. The floor and ceiling prices related to domestic and Canadian oil production are based on the NYMEX price. The floor and ceiling prices related to international oil production are based on the Brent price. If the NYMEX or Brent price is outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. As long as Devon meets the ongoing requirements of hedge accounting for its derivatives, any such settlements will either increase or decrease Devon's oil revenues for the period. Because Devon's oil volumes are often sold at prices that differ from the NYMEX or Brent price due to differing quality (i.e., sweet crude versus heavy or sour crude) and transportation costs from different geographic areas, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2005 natural gas production that otherwise is subject to floating prices. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's gas revenues for the period. Because Devon's gas volumes are often sold at prices that differ from the related regional indices, and due to differing Btu contents of gas produced, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

The floor and ceiling prices shown in the following table are weighted averages of the various collars. The international oil prices shown in the following table have been adjusted to a NYMEX-based price, using Devon's estimates of 2005 differentials between NYMEX and the Brent price upon which the collars are based.

The natural gas prices shown in the following table have been adjusted to a NYMEX-based price, using Devon's estimates of future differentials between NYMEX and the specific regional indices upon which the collars are based. The floor and ceiling prices related to the collars are based on various regional first-of-the-month price indices as published monthly by *Inside FERC*.

OIL PRODUCTION			
		WEIGHTED AVERAGE	
YEAR	BBLS/DAY	FLOOR PRICE PER BBL	CEILING PRICE PER BBL
2005	50,000	$ 22.45	$ 28.45

GAS PRODUCTION			
		WEIGHTED AVERAGE	
YEAR	MMBTU/DAY	FLOOR PRICE PER MMBTU	CEILING PRICE PER MMBTU
2005	94,548	$ 3.83	$ 7.21

Interest Rate Swaps

Devon has also entered into a floating-to-fixed interest rate swap and fixed-to-floating interest rate swaps. Under the floating-to-fixed interest rate swap, Devon will record a fixed rate of 6.4% on a notional amount of $104 million in 2005 and 2006 and 6.3% on a notional amount of $32 million in 2007. 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
7.625% senior notes due in 2005	$ 125	LIBOR plus 237 basis points
10.25% bonds due in 2005	$ 235	LIBOR plus 711 basis points
2.75% notes due in 2006	$ 500	LIBOR less 26.8 basis points
6.55% senior notes due 2006	$ 166 (1)	Banker's Acceptance plus 340 basis points
4.375% senior notes due in 2007	$ 400	LIBOR plus 40 basis points
6.75% senior notes due 2011	$ 400	LIBOR plus 197 basis points

(1) Converted from $200 million Canadian dollars at a Canadian-to-U.S. dollar exchange rate of $0.8308 as of December 31, 2004.

13 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.

During 2002, Devon established a funding policy regarding the Qualified Plans such that it would contribute the amount of funds necessary so that the Qualified Plans' assets would be approximately equal to the related accumulated benefit obligation by the end of 2004. As of December 31, 2004, the fair value of the Qualified Plans' assets was $456 million, which was $11 million more 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 $60 million and $66 million at December 31, 2004, and 2003, respectively, and are included in noncurrent 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

Devon uses a measurement date of December 31 for its pension and postretirement benefit plans. The following table presents the plans' benefit obligations and the weighted-average actuarial assumptions used to calculate such obligations at December 31, 2004, and 2003. 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, 2004, and 2003 was $542 million and $475 million, respectively.

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
	(In millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 512	460	70	69
Service cost	15	12	1	1
Interest cost	32	31	3	4
Participant contributions	—	—	1	1
Amendments	1	1	(7)	(1)
Mergers and acquisitions	—	19	—	—
Special termination benefits	1	—	—	—
Foreign exchange rate changes	2	4	—	—
Actuarial loss (gain)	52	28	(10)	3
Benefits paid	(27)	(43)	(8)	(7)
Benefit obligation at end of year	$ 588	512	50	70
Actuarial assumptions:				
Discount rate	5.74%	6.23%	5.75%	6.25%
Rate of compensation increase	4.50%	4.88%	N/A	N/A

For measurement purposes, a 10% annual rate of increase in the per capita cost of covered health care benefits, excluding prescription benefits, was assumed for 2005. The rate was assumed to decrease one percent annually to 5% in the year 2010 and remain at that level thereafter. Additionally, an 11% annual rate of increase in the per capita cost of covered prescription benefits was assumed for 2005. The rate was assumed to decrease approximately one percent annually to 5.25% in the year 2010 and remain at that level thereafter. A one-percentage-point increase in assumed health care cost trend rates would increase the December 31, 2004 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, 2004 and 2003.

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
	(In millions)			
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 375	281	—	—
Actual return on plan assets	40	70	—	—
Employer contributions	70	67	7	6
Participant contributions	—	—	1	1
Transfer to defined contribution plan	(3)	(3)	—	—
Benefits paid	(27)	(43)	(8)	(7)
Foreign exchange rate changes	1	3	—	—
Fair value of plan assets at end of year	$ 456	375	—	—

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 $6 million in 2004 and $22 million in 2003 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, 2004, 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, 2004 and 2003, and the target allocation for 2005, by asset category, follows:

	TARGET ALLOCATION	PERCENTAGE OF PLAN ASSETS AT YEAR END	
	2005	2004	2003
Equity securities	80%	82%	79%
Debt securities	20%	17%	19%
Other	0%	1%	2%
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, 2004, and 2003.

	PENSION BENEFITS		OTHER POSTRETIREMENT BENEFITS	
	2004	2003	2004	2003
	(IN MILLIONS)			
Net amounts recognized in consolidated balance sheets:				
Fair value of plan assets	$ 456	375	—	—
Benefit obligations	588	512	50	70
Funded status	(132)	(137)	(50)	(70)
Unrecognized net actuarial loss	155	119	1	11
Unrecognized prior service cost (benefit)	5	5	(9)	(2)
Net amounts recognized	$ 28	(13)	(58)	(61)
Components of net amounts recognized in the consolidated balance sheets:				
Prepaid cost	$ 98	—	—	—
Accrued benefit cost	(96)	(102)	(58)	(61)
Intangible asset	4	4	—	—
Accumulated other comprehensive income	22	85	—	—
Net amount recognized	$ 28	(13)	(58)	(61)

During 2004 and 2003, the pre-tax change in the minimum pension liability increased other comprehensive income by $61 million and $28 million, respectively. During 2002, the pre-tax change in the minimum pension liability decreased other comprehensive income by $85 million.

Certain of Devon's pension and postretirement plans have a projected benefit obligation in excess of plan assets at December 31, 2004 and 2003. The aggregate benefit obligation and fair value of plan assets for these plans is included below.

	DECEMBER 31,	
	2004	2003
	(IN MILLIONS)	
Projected benefit obligation	$ 626	571
Fair value of plan assets	$ 441	359

Certain of Devon's pension plans have an accumulated benefit obligation in excess of plan assets at December 31, 2004 and 2003. The aggregate accumulated benefit obligation and fair value of plan assets for these plans is included below.

	DECEMBER 31,	
	2004	2003
	(IN MILLIONS)	
Accumulated benefit obligation	$ 98	465
Fair value of plan assets	$ —	359

The plan assets included in the tables above exclude the Supplemental Plan trusts which had a total value of $60 million and $66 million at December 31, 2004 and 2003, 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, 2004, 2003 and 2002.

	Pension Benefits			Other Postretirement Benefits		
	2004	2003	2002	2004	2003	2002
	(In millions)					
Components of net periodic benefit cost:						
Service cost	$ 15	12	9	1	1	1
Interest cost	32	31	28	4	4	4
Expected return on plan assets	(30)	(22)	(24)	—	—	—
Curtailment loss	—	1	—	—	—	—
Termination benefits	1	—	—	—	—	—
Amortization of prior service cost	1	1	1	(1)	—	—
Recognized net actuarial loss	7	12	2	—	—	—
Net periodic benefit cost	$ 26	35	16	4	5	5
Actuarial assumptions:						
Discount rate	6.23%	6.53%	7.10%	6.25%	6.75%	7.15%
Expected return on plan assets	8.34%	8.25%	8.27%	N/A	N/A	N/A
Rate of compensation increase	4.88%	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. 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 will 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.

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 – 2005	$ 6	6
Benefit payments:		
2005	29	6
2006	31	6
2007	32	6
2008	34	6
2009	35	5
2010 – 2014	208	24

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 2005, $6 million is expected to be funded from the trusts established for the Supplemental Plans and $6 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 and $6 million at December 31, 2004 and 2003, respectively.

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 $11 million, $10 million and $8 million for the years ended December 31, 2004, 2003 and 2002, 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 2004, 2003 and 2002, Devon's combined contributions to the Canadian defined contribution plan and the Canadian savings plan were $9 million, $8 million and $8 million, respectively.

14 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, 2004, Devon's consolidated balance sheet included $7 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 is 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. Devon believes that it has acted reasonably and paid royalties in good faith and in accordance with its obligations under its oil and gas leases and applicable law, and Devon does not believe that it is subject to material exposure in association with this litigation.

Tax Treatment of Exchangeable Debentures

As described more fully in Note 8, Devon has certain exchangeable debentures, with a principal amount totaling $760 million, which are exchangeable at the option of the holders into shares of ChevronTexaco common stock owned by Devon. The debentures were assumed, and the ChevronTexaco common stock was acquired, by Devon in the 1999 PennzEnergy merger.

The Internal Revenue Service ("IRS") recently examined the 1998 income tax return of PennzEnergy's predecessor, and the IRS formally notified Devon in April 2004 that it disagreed with certain tax treatments of the exchangeable debentures and similar exchangeable debentures retired in 1998. Devon did not agree with the IRS positions and contested the claim of additional taxes. In June 2004, Devon formally protested the IRS notice and requested a conference with the IRS Appeals Office. A preliminary appeals conference was held in October 2004, and additional appeals meetings were held in November and December 2004. This matter was resolved in February 2005, when the IRS agreed with Devon and concluded that no taxes were due.

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.

Operating Leases

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 $49 million, $51 million and $37 million in 2004, 2003 and 2002, 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 operating leases are for 20-year terms and contain various options whereby Devon may purchase the lessors' interests in the spars. Total rental expense included in lease operating expenses under these operating leases was $17 million and $11 million in 2004 and 2003, respectively. Devon has guaranteed that the spars will have residual values at the end of the operating leases equal to at least 10% of the fair value of the spars at the inception of the leases. The total guaranteed value is $20 million in 2022. However, such amount may be reduced under the terms of the lease agreements.

Devon also has two floating, production, storage and offloading facilities ("FPSO") that are being leased under operating lease arrangements. One FPSO is being used in the Panyu project offshore China, and the other is being used in the Zafiro field offshore Equatorial Guinea. The China lease expires in September 2009 and the Equatorial Guinea lease expires in July 2009. Total rental expense included in lease operating expenses under these operating leases was $20 million and $6 million in 2004 and 2003, respectively.

The following is a schedule by year of future minimum rental payments required under office and equipment, spar and FPSO leases that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 2004:

YEAR ENDING DECEMBER 31,	OFFICE AND EQUIPMENT LEASES	SPAR LEASES	FPSO LEASES
		(IN MILLIONS)	
2005	$ 35	15	20
2006	30	15	20
2007	28	15	20
2008	25	15	19
2009	23	14	13
Thereafter	69	228	—
Total minimum lease payments	$ 210	302	92

15 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. Devon has entered into various derivative instruments that are accounted for as cash flow hedges. These instruments, which consist of price swaps and costless price collars, and the related future production volumes, are discussed in Note 12. The effect of these hedges has been considered in calculating the full cost ceiling limitations as of December 31, 2004. These hedges reduced the full cost ceiling limitations for the United States, Canada and Equatorial Guinea as of the end of 2004 by $102 million, $77 million and $76 million, respectively. However, the 2004 capitalized costs in these countries did not exceed the related ceiling limitations, with or without the effects of the hedges.

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 2003 and 2002, Devon reduced the carrying value of its oil and gas properties by $68 million and $651 million, respectively, due to the full cost ceiling limitations. The after-tax effects of these reductions in 2003 and 2002 were $36 million and $371 million, respectively. The following table summarizes these reductions by geographic area.

	YEAR ENDED DECEMBER 31,			
	2003		2002	
	GROSS	NET OF TAXES	GROSS	NET OF TAXES
		(IN MILLIONS)		
Canada	$ —	—	651	371
International	68	36	—	—
Total	$ 68	36	651	371

The 2003 reduction in carrying value was related to properties in Egypt, Russia and Indonesia. 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. As a result, Devon's Egyptian, Russian and Indonesian costs to be recovered exceeded the related ceiling value by $26 million, $9 million and $1 million, respectively. These after-tax amounts resulted in pre-tax reductions of the carrying values of Devon's Egyptian, Russian and Indonesian oil and gas properties of $45 million, $19 million and $4 million, respectively, in the fourth quarter of 2003.

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 Devon's internal criteria to justify further investment. Accordingly, Devon recorded a $43 million charge associated with the impairment of these properties. The after-tax effect of this reduction was $38 million.

The 2002 Canadian reduction was primarily the result of lower prices. The recorded values of oil and gas properties added from the Anderson acquisition in 2001 were based on expected future oil and gas prices that were higher than the June 30, 2002, prices used to calculate the Canadian ceiling.

16 DISCONTINUED OPERATIONS

On April 18, 2002, Devon sold its Indonesian operations to PetroChina Company Limited for total cash consideration of $250 million. On October 25, 2002, Devon sold its Argentine operations to Petroleo Brasileiro S.A. for total cash consideration of $90 million. On January 27, 2003, Devon sold its Egyptian operations to IPR Transoil Corporation for total cash consideration of $7 million.

As a result, Devon reclassified its Indonesian, Argentine and Egyptian activities as discontinued operations. This reclassification affects the 2002 presentation of financial results. 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 in 2004 and 2003. The revenues from these discontinued operations for the year ended December 31, 2002 (in millions) are presented below:

Oil sales	$ 72
Gas sales	7
NGL sales	1
Total revenues	$ 80

17 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 18.

Following is certain financial information regarding Devon's segments for 2004, 2003 and 2002. The revenues reported are all from external customers.

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
As of December 31, 2004				
Current assets	$ 2,038	1,018	527	3,583
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	$ 17,233	9,286	3,217	29,736
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	2,695	1,714	391	4,800
Stockholders' equity	8,297	2,966	2,411	13,674
Total liabilities and stockholders' equity	$ 17,233	9,286	3,217	29,736

		U.S.	CANADA	INTERNATIONAL	TOTAL
			(IN MILLIONS)		
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
Operating costs and expenses:					
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
Total operating costs and expenses		3,887	1,056	542	5,485
Earnings from operations		2,443	836	425	3,704
Other income (expenses):					
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		81	17	5	103
Net other income (expenses)		(179)	(238)	6	(411)
Earnings before income taxes		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
Capital expenditures	$	1,785	975	343	3,103

		U.S.	CANADA	INTERNATIONAL	TOTAL
			(IN MILLIONS)		
As of December 31, 2003					
Current assets	$	1,411	643	310	2,364
Property and equipment, net of accumulated depreciation, depletion and amortization		10,753	4,900	2,681	18,334
Goodwill		3,073	2,336	68	5,477
Other assets		908	27	52	987
Total assets	$	16,145	7,906	3,111	27,162
Current liabilities	$	1,320	458	293	2,071
Long-term debt		4,810	3,770	—	8,580
Asset retirement obligation, long-term		386	218	25	629
Other liabilities		371	20	10	401
Preferred stock of a subsidiary		55	—	—	55
Deferred income taxes		2,471	1,433	466	4,370
Stockholders' equity		6,732	2,007	2,317	11,056
Total liabilities and stockholders' equity	$	16,145	7,906	3,111	27,162

	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
Operating costs and expenses:				
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
Total operating costs and expenses	3,452	859	399	4,710
Earnings from operations	1,793	812	37	2,642
Other income (expenses):				
Interest expense	(211)	(285)	(6)	(502)
Dividends on subsidiary's preferred stock	(2)	—	—	(2)
Effects of changes in foreign currency exchange rates	—	69	—	69
Change in fair value of financial instruments	2	(1)	—	1
Other income	21	8	8	37
Net other income (expenses)	(190)	(209)	2	(397)
Earnings before income taxes 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
Capital expenditures	$ 1,579	704	304	2,587

		U.S.	CANADA	INTERNATIONAL	TOTAL
			(IN MILLIONS)		
Year Ended December 31, 2002					
Revenues:					
Oil sales	$	524	331	54	909
Gas sales		1,403	730	—	2,133
NGL sales		192	83	—	275
Marketing and midstream revenues		985	14	—	999
Total revenues		3,104	1,158	54	4,316
Operating costs and expenses:					
Lease operating expenses		453	310	12	775
Production taxes		104	7	—	111
Marketing and midstream operating costs and expenses		800	8	—	808
Depreciation, depletion and amortization of oil and gas properties		737	364	5	1,106
Depreciation and amortization of non-oil and gas properties		97	7	1	105
General and administrative expenses		166	40	13	219
Reduction in carrying value of oil and gas properties		—	651	—	651
Total operating costs and expenses		2,357	1,387	31	3,775
Earnings (loss) from operations		747	(229)	23	541
Other income (expenses):					
Interest expense		(235)	(295)	(3)	(533)
Effects of changes in foreign currency exchange rates		—	1	—	1
Change in fair value of financial instruments		31	(3)	—	28
Impairment of ChevronTexaco Corporation common stock		(205)	—	—	(205)
Other income		16	11	7	34
Net other income (expenses)		(393)	(286)	4	(675)
Earnings (loss) from continuing operations before income taxes		354	(515)	27	(134)
Income tax expense (benefit):					
Current		(23)	28	18	23
Deferred		42	(253)	(5)	(216)
Total income tax expense (benefit)		19	(225)	13	(193)
Earnings (loss) from continuing operations		335	(290)	14	59
Discontinued operations:					
Results of discontinued operations before income taxes		—	—	54	54
Income tax expense		—	—	9	9
Net results of discontinued operations		—	—	45	45
Net earnings (loss)	$	335	(290)	59	104
Capital expenditures	$	2,797	532	97	3,426

18 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,		
	2004	2003	2002
		(IN MILLIONS)	
Property acquisition costs:			
Proved properties	$ 38	4,343	1,538
Unproved properties – business combinations	—	1,063	639
Unproved properties – other acquisitions	141	87	64
Total unproved properties	141	1,150	703
Exploration costs	735	714	383
Development costs	1,938	1,864	1,140
Costs incurred	$ 2,852	8,071	3,764

	DOMESTIC		
	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
		(IN MILLIONS)	
Property acquisition costs:			
Proved properties	$ 27	2,697	1,536
Unproved properties – business combinations	—	551	639
Unproved properties – other acquisitions	75	48	27
Total unproved properties	75	599	666
Exploration costs	335	343	161
Development costs	1,163	1,193	808
Costs incurred	$ 1,600	4,832	3,171

	CANADA		
	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
		(IN MILLIONS)	
Property acquisition costs:			
Proved properties	$ 11	26	2
Unproved properties – business combinations	—	—	—
Unproved properties – other acquisitions	52	39	28
Total unproved properties	52	39	28
Exploration costs	272	214	207
Development costs	625	491	299
Costs incurred	$ 960	770	536

	INTERNATIONAL		
	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
		(IN MILLIONS)	
Property acquisition costs:			
Proved properties	$ —	1,620	—
Unproved properties – business combinations	—	512	—
Unproved properties – other acquisitions	14	—	9
Total unproved properties	14	512	9
Exploration costs	128	157	15
Development costs	150	180	33
Costs incurred	$ 292	2,469	57

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 $172 million, $140 million and $97 million in the years 2004, 2003 and 2002, 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, $50 million and $4 million in the years 2004, 2003 and 2002, respectively.

The preceding Total and International cost incurred tables exclude $16 million in 2002 related to discontinued operations.

As discussed in Note 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.

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,		
	2004	2003	2002
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and NGL sales	$ 7,488	5,892	3,317
Production and operating expenses	(1,535)	(1,282)	(886)
Depreciation, depletion and amortization	(2,141)	(1,668)	(1,106)
Accretion of asset retirement obligation	(44)	(36)	—
General and administrative expenses directly related to oil and gas producing activities	(38)	(48)	(29)
Reduction of carrying value of oil and gas properties	—	(111)	(651)
Income tax expense	(1,288)	(895)	(234)
Results of operations for oil and gas producing activities	$ 2,442	1,852	411
Depreciation, depletion and amortization per equivalent barrel of production	$ 8.54	7.33	5.88

	DOMESTIC YEAR ENDED DECEMBER 31,		
	2004	2003	2002
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and NGL sales	$ 4,642	3,802	2,119
Production and operating expenses	(934)	(811)	(557)
Depreciation, depletion and amortization	(1,242)	(1,084)	(737)
Accretion of asset retirement obligation	(27)	(22)	—
General and administrative expenses directly related to oil and gas producing activities	(22)	(27)	(14)
Income tax expense	(827)	(775)	(295)
Results of operations for oil and gas producing activities	$ 1,590	1,083	516
Depreciation, depletion and amortization per equivalent barrel of production	$ 8.23	7.42	6.22

		CANADA		
		YEAR ENDED DECEMBER 31,		
		2004	2003	2002
		(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and NGL sales	$	1,879	1,654	1,144
Production and operating expenses		(443)	(395)	(317)
Depreciation, depletion and amortization		(522)	(388)	(364)
Accretion of asset retirement obligation		(15)	(13)	—
General and administrative expenses directly related to oil and gas producing activities		(16)	(15)	(14)
Reduction of carrying value of oil and gas properties		—	—	(651)
Income tax (expense) benefit		(275)	(89)	74
Results of operations for oil and gas producing activities	$	608	754	(128)
Depreciation, depletion and amortization per equivalent barrel of production	$	8.00	6.17	5.39

		INTERNATIONAL		
		YEAR ENDED DECEMBER 31,		
		2004	2003	2002
		(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and NGL sales	$	967	436	54
Production and operating expenses		(158)	(76)	(12)
Depreciation, depletion and amortization		(377)	(196)	(5)
Accretion of asset retirement obligation		(2)	(1)	—
General and administrative expenses directly related to oil and gas producing activities		—	(6)	(1)
Reduction of carrying value of oil and gas properties		—	(111)	—
Income tax expense		(186)	(31)	(13)
Results of operations for oil and gas producing activities	$	244	15	23
Depreciation, depletion and amortization per equivalent barrel of production	$	10.88	10.52	2.40

The preceding Total and International results of oil and gas producing activities tables exclude $19 million in 2002 related to discontinued operations.

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 2004, 2003 and 2002.

	2004		2003		2002	
	PREPARED	AUDITED	PREPARED	AUDITED	PREPARED	AUDITED
Domestic	16%	61%	33%	37%	12%	61%
Canada	22%	—	28%	—	31%	—
International	98%	—	98%	—	100%	—

“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, 2004.

TOTAL				
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2001	527	5,024	108	1,472
Revisions due to prices	(19)	27	2	(12)
Revisions other than price	9	(108)	(2)	(11)
Extensions and discoveries	36	570	11	142
Purchase of reserves	13	1,723	105	405
Production	(42)	(761)	(19)	(188)
Sale of reserves	(80)	(639)	(13)	(199)
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
Proved developed reserves as of:				
December 31, 2001	298	3,911	88	1,038
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

DOMESTIC				
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2001	191	2,399	52	642
Revisions due to prices	13	74	3	29
Revisions other than price	(5)	(48)	(1)	(14)
Extensions and discoveries	10	344	6	73
Purchase of reserves	12	1,722	105	404
Production	(24)	(482)	(14)	(118)
Sale of reserves	(50)	(457)	(5)	(131)
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
Proved developed reserves as of:				
December 31, 2001	167	1,988	48	546
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

	CANADA			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2001	166	2,625	56	660
Revisions due to prices	(2)	(47)	(1)	(11)
Revisions other than price	4	(60)	(1)	(7)
Extensions and discoveries	26	226	5	69
Purchase of reserves	1	1	—	1
Production	(16)	(279)	(5)	(68)
Sale of reserves	(30)	(182)	(8)	(68)
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
Proved developed reserves as of:				
December 31, 2001	124	1,923	40	485
December 31, 2002	119	1,816	33	455
December 31, 2003	123	1,964	43	493
December 31, 2004	123	2,043	43	507

	INTERNATIONAL			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2001	170	—	—	170
Revisions due to prices	(30)	—	—	(30)
Revisions other than price	10	—	—	10
Extensions and discoveries	—	—	—	—
Purchase of reserves	—	—	—	—
Production	(2)	—	—	(2)
Sale of reserves	—	—	—	—
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
Proved developed reserves as of:				
December 31, 2001	7	—	—	7
December 31, 2002	6	—	—	6
December 31, 2003	114	81	—	127
December 31, 2004	120	71	—	131

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

The preceding Total and International quantities of oil and gas reserves tables exclude the following proved reserves and proved developed reserves related to discontinued operations.

	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of:				
December 31, 2001	59	453	13	147
December 31, 2002	1	—	—	1
Proved developed reserves as of:				
December 31, 2001	26	37	—	32
December 31, 2002	—	—	—	—

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 YEAR ENDED DECEMBER 31,		
	2004	2003	2002
	(IN MILLIONS)		
Future cash inflows	$ 67,035	60,562	38,399
Future costs:			
Development	(4,250)	(3,693)	(2,053)
Production	(18,395)	(16,232)	(9,076)
Future income tax expense	(14,241)	(12,078)	(8,737)
Future net cash flows	30,149	28,559	18,533
10% discount to reflect timing of cash flows	(14,064)	(12,638)	(8,168)
Standardized measure of discounted future net cash flows	$ 16,085	15,921	10,365

	DOMESTIC YEAR ENDED DECEMBER 31,		
	2004	2003	2002
	(IN MILLIONS)		
Future cash inflows	$ 39,214	36,602	20,571
Future costs:			
Development	(2,208)	(2,028)	(1,122)
Production	(12,093)	(10,788)	(5,871)
Future income tax expense	(7,989)	(6,848)	(3,911)
Future net cash flows	16,924	16,938	9,667
10% discount to reflect timing of cash flows	(7,550)	(7,435)	(4,157)
Standardized measure of discounted future net cash flows	$ 9,374	9,503	5,510

	CANADA YEAR ENDED DECEMBER 31,		
	2004	2003	2002
	(IN MILLIONS)		
Future cash inflows	$ 18,483	15,517	13,799
Future costs:			
Development	(1,353)	(1,051)	(633)
Production	(4,285)	(3,585)	(2,600)
Future income tax expense	(4,200)	(3,316)	(3,999)
Future net cash flows	8,645	7,565	6,567
10% discount to reflect timing of cash flows	(4,764)	(3,442)	(2,677)
Standardized measure of discounted future net cash flows	$ 3,881	4,123	3,890

		INTERNATIONAL		
		YEAR ENDED DECEMBER 31,		
		2004	2003	2002
			(IN MILLIONS)	
Future cash inflows	$	9,338	8,443	4,029
Future costs:				
Development		(689)	(614)	(298)
Production		(2,017)	(1,859)	(605)
Future income tax expense		(2,052)	(1,914)	(827)
Future net cash flows		4,580	4,056	2,299
10% discount to reflect timing of cash flows		(1,750)	(1,761)	(1,334)
Standardized measure of discounted future net cash flows	$	2,830	2,295	965

Future cash inflows are computed by applying year-end prices (averaging $34.94 per barrel of oil, $5.46 per Mcf of gas and $22.84 per barrel of natural gas liquids at December 31, 2004) 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. Such arrangements include derivatives accounted for as cash flow hedges.

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 $4.3 billion of future development costs, $818 million, $588 million and $388 million are estimated to be spent in 2005, 2006 and 2007, respectively.

Future development costs include not only development costs, but also future dismantlement, abandonment and rehabilitation costs. Included as part of the $4.3 billion of future development costs are $1.0 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.

The preceding Total and International standardized measure of discounted future net cash flows tables exclude $21 million in 2002 related to discontinued 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,		
		2004	2003	2002
			(IN MILLIONS)	
Beginning balance	$	15,921	10,365	5,015
Oil, gas and NGL sales, net of production costs		(5,915)	(4,562)	(2,402)
Net changes in prices and production costs		2,749	2,645	9,122
Extensions, discoveries, and improved recovery, net of future development costs		3,103	2,218	1,471
Purchase of reserves, net of future development costs		32	5,763	888
Development costs incurred during the period which reduced future development costs		684	1,022	175
Revisions of quantity estimates		(1,132)	(728)	(61)
Sales of reserves in place		(13)	(307)	(1,879)
Accretion of discount		2,265	1,531	692
Net change in income taxes		(1,782)	(2,305)	(2,673)
Other, primarily changes in timing		173	279	17
Ending balance	$	16,085	15,921	10,365

The preceding table excludes $21 million and $299 million as of December 31, 2002 and 2001, respectively, related to discontinued operations.

19 SUPPLEMENTAL QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Following is a summary of the unaudited interim results of operations for the years ended December 31, 2004 and 2003.

	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

	2003				
	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	FULL YEAR
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)				
Oil, gas and NGL sales	$ 1,237	1,478	1,613	1,564	5,892
Total revenues	$ 1,671	1,813	1,948	1,921	7,352
Net earnings before cumulative effect of change in accounting principle	$ 420	356	412	543	1,731
Net earnings	$ 436	356	412	543	1,747
Net earnings per common share:					
Basic:					
Net earnings before cumulative effect of change in accounting principle	$ 1.33	0.84	0.88	1.16	4.12
Cumulative effect of change in accounting principle	0.05	—	—	—	0.04
Total basic	$ 1.38	0.84	0.88	1.16	4.16
Diluted:					
Net earnings before cumulative effect of change in accounting principle	$ 1.29	0.81	0.85	1.13	4.00
Cumulative effect of change in accounting principle	0.05	—	—	—	0.04
Total diluted	$ 1.34	0.81	0.85	1.13	4.04

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 fourth quarter of 2003 includes a $218 million income tax benefit due to a statutory rate reduction of Canadian tax rates. The per share effect of this tax benefit was $0.45. The fourth quarter of 2003 also includes $111 million of reduction of carrying value of oil and gas properties. The after-tax effect of the reduction in carrying value was $74 million, or $0.16 per share.

Reports on Internal Control Over Financial Reporting

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 18, 2005, management concluded that its internal control over financial reporting was effective as of December 31, 2004.

Management's assessment of the effectiveness of Devon's internal control over financial reporting as of December 31, 2004 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, 2004, 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, 2004, 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, 2004, 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, 2004, 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, 2004 and 2003, 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, 2004, and our report dated March 4, 2005 expressed an unqualified opinion on those consolidated financial statements.

Oklahoma City, Oklahoma
March 4, 2005

Non-GAAP Financial Measures

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 debentures exchangeable into shares of ChevronTexaco common stock, for the calculation of total capitalization provides a better measure than using debt. Management 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 these assets to repay debt. Furthermore, included in Devon's indebtedness are $692 million of debentures that are exchangeable into 14.2 million shares of ChevronTexaco common stock owned outright by Devon. Since these shares, with a market value of $745 million as of December 31, 2004, are being held by Devon exclusively to satisfy the related indebtedness, Devon believes that netting the value of the debentures provides a clearer picture of the 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

		DECEMBER 31, 2004	DECEMBER 31, 2003
		(IN MILLIONS)	
Net Debt			
Total debt (GAAP)	$	7,964	8,918
Adjustments:			
Cash and short-term investments		(2,119)	(1,273)
Debentures exchangeable into ChevronTexaco Corporation common stock		(692)	(677)
Net Debt (Non-GAAP)	$	5,153	6,968
Total Capitalization			
Total debt	$	7,964	8,918
Stockholders' equity		13,674	11,056
Total Capitalization (GAAP)	$	21,638	19,974
Adjusted Capitalization			
Net debt	$	5,153	6,968
Stockholders' equity		13,674	11,056
Adjusted Capitalization (Non-GAAP)	$	18,827	18,024

Drill-bit capital, a non-GAAP measure, 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. Management believes drill-bit capital is relevant because it provides additional insight into costs associated with current year drilling, facilities and unproved acreage acquisitions related to the company's exploration program. 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.

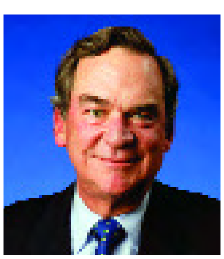
		YEAR ENDED DECEMBER 31, 2004	YEAR ENDED DECEMBER 31, 2003
		(IN MILLIONS)	
Drill-bit Capital			
Costs Incurred (GAAP)	$	2,852	8,071
Less:			
Proven acquisition costs		38	4,209
Unproven acquisition costs resulting from business combinations		—	1,063
Accrued asset retirement costs		51	182
Plus: Actual retirement expenditures		42	37
Drill-bit capital (Non-GAAP)	$	2,805	2,654

Directors

JOHN W. NICHOLS, 90, 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.

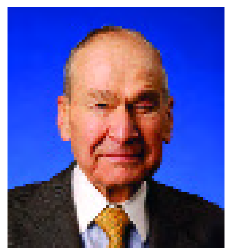
J. LARRY NICHOLS, 62, is a co-founder of Devon. He was named chairman of the board of directors in 2000. He has been a director since 1971. Nichols served as president from 1976 until 2003 and has served as chief executive officer since 1980. Nichols serves as a director of Smedvig ASA and Baker Hughes Inc. He is a director of the Oklahoma City Branch of the Federal Reserve Bank of Kansas City. Nichols 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, 68, joined the board of directors in 1982 and serves as chairman of the Audit Committee. Ferguson is the 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.

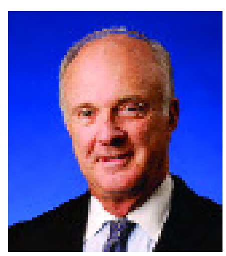


PETER J. FLUOR, 57, joined the board of directors in 2003. Fluor previously served as a director of Ocean Energy Inc. from 1980 to 2003. He has been chairman and chief executive officer of Texas Crude Energy Inc., a private oil and gas company, since January 2001. From 1997 through 2000, Fluor was president 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, 70, joined the board of directors in 1979 and serves as 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. 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.

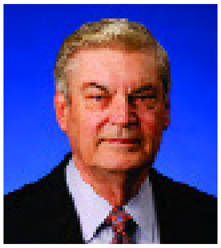


MICHAEL E. GELLERT, 73, joined the board of directors in 1971 and serves as chairman of the Nominating and Governance Committee. Gellert has been a general partner of Windcrest Partners, a private investment partnership in New York City, since 1967. From January 1958 until his retirement in October 1989, Gellert served in executive capacities with Drexel Burnham Lambert Inc. and its predecessors in New York City. In addition to serving as a member of Devon's board of directors, Gellert serves on the boards of Humana Inc., Seacor Smit Inc., Six Flags Inc., Travelers Series Fund Inc., Dalet Technologies and Smith Barney World Funds.



JOHN A. HILL, 63, joined the board of directors in 2000 following Devon's merger with Santa Fe Snyder. 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.

ROBERT L. HOWARD, 68, 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. from 1996 to 2003. 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, 70, joined the board of directors in 1999. Johnson previously served as a director of PennzEnergy Co. and has been a private consultant in the oil and gas industry for more than five 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, 56, 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., a privately held energy corporation. Kanovsky continues to be active in the Canadian energy industry and is currently a director of Accrete Energy Inc., ARC Resources Ltd., Bonavista Petroleum Ltd., Pure Technologies Ltd. and TransAlta Corp.

CHARLES F. MITCHELL, M.D., 56, joined the board of directors in 2003. Mitchell previously served as a director of Ocean Energy Inc. from 1995 to 2003. He is a physician and surgeon and has been a senior partner of ENT Medical Center in Baton Rouge, La., since 1985. Mitchell is involved in numerous private investments.

J. TODD MITCHELL, 46, 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.

ROBERT A. MOSBACHER JR., 53, joined the board of directors in 1999 following Devon's merger with PennzEnergy Co. He has served as president and chief executive officer of Mosbacher Energy Co. since 1986. Mosbacher is currently a director of JPMorgan Chase & Co., Houston Regional Board, and is on the executive committee of the U.S. Oil & Gas Association.

Senior Officers

JOHN RICHELS, 53, 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, 49, was named senior vice president, Exploration and Production, in 2004. Hadden joined Texaco, now ChevronTexaco, 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 Production; division manager for the Bakersfield

Senior Officers

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, 44, 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, 63, 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, 54, was elected to the position of senior vice president, Administration, in 1999. Moon is responsible for Human Resources, Office Administration, Information Technology, Process Development and Corporate Governance. Moon has been with Devon for 20 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, 57, 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 of Terms

Bitumen: A viscous, tar-like oil that requires non-conventional 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.

Deepwater: In offshore areas, water depths of greater than 600 feet.

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 its geographical location 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.

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.

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.

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 and government take, multiplied by one's fractional working interest.

Proppant: Granular particles mixed with the fracturing fluid to hold open the formation cracks created by a fracture treatment.

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 landowner's share of the value of minerals (oil and gas) produced on the property.

SEC Case: The method for calculating future net revenues from proved reserves as established by the Securities and Exchange Commission (SEC). Future oil and gas revenues are estimated using essentially fixed or unescalated prices. Future production and development costs also are unescalated and are subtracted from future revenues.

SEC @ 10% or SEC 10% present value: The future net revenue anticipated from proved reserves using the SEC Case, discounted at 10%.

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.

Stepout 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.

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.

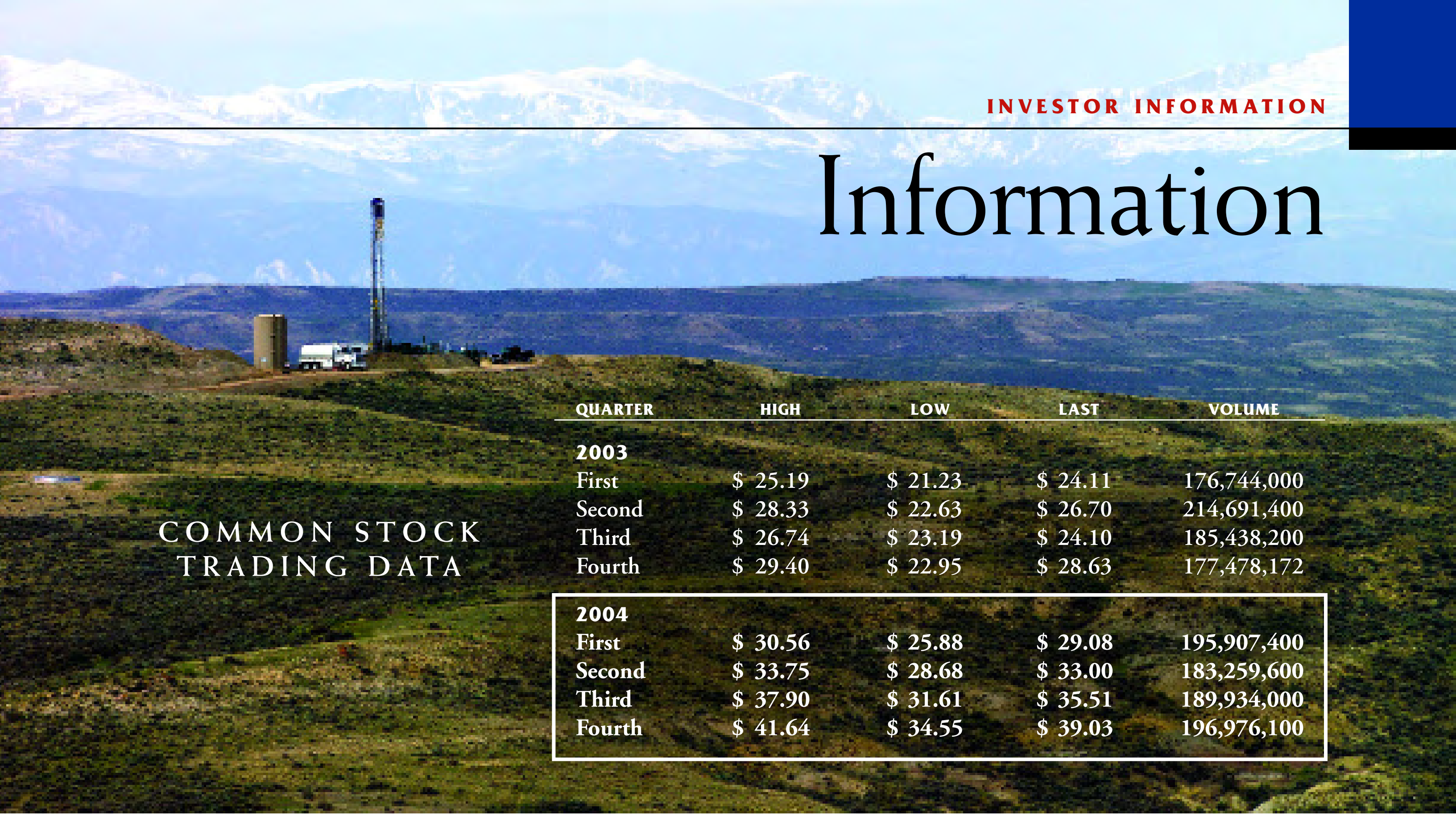
VOLUME ACRONYMS

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



Information

COMMON STOCK TRADING DATA

QUARTER	HIGH	LOW	LAST	VOLUME
2003				
First	$ 25.19	$ 21.23	$ 24.11	176,744,000
Second	$ 28.33	$ 22.63	$ 26.70	214,691,400
Third	$ 26.74	$ 23.19	$ 24.10	185,438,200
Fourth	$ 29.40	$ 22.95	$ 28.63	177,478,172
2004				
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**

CORPORATE HEADQUARTERS
Devon Energy Corporation
20 North Broadway
Oklahoma City, OK 73102-8260
Telephone: (405) 235-3611
Fax: (405) 552-4550

PERMIAN, MID-CONTINENT, ROCKY MOUNTAINS and MARKETING AND MIDSTREAM OPERATIONS
Devon Energy Corporation
20 North Broadway
Oklahoma City, OK 73102-8260
Telephone: (405) 235-3611
Fax: (405) 552-4550

GULF, GULF COAST and INTERNATIONAL OPERATIONS
Devon Energy Corporation
Devon Energy Tower
1200 Smith Street
Houston, TX 77002-4313
Telephone: (713) 286-5700

CANADIAN OPERATIONS
Devon Canada Corporation
2000, 400 - 3rd Avenue S.W.
Calgary, Alberta T2P 4H2
Telephone: (403) 232-7100

SHAREHOLDER ASSISTANCE
For information about transfer or exchange of shares, dividends, address changes, account consolidation, multiple mailings, lost certificates and Form 1099:

Wachovia Bank, N.A.
Shareholder Services Group
1525 West W.T. Harris Blvd.
Bldg. 3C, 3rd Floor
Charlotte, NC 28288-1153
Toll Free: (800) 829-8432

COMPANY CONTACTS
Vince White, Vice President
Communications and Investor Relations
Telephone: (405) 552-4505
E-mail: vince.white@dvn.com

Investor Relations:
Zack Hager
Manager, Investor Relations
Telephone: (405) 552-4526
E-mail: zack.hager@dvn.com

Scott Smalling
Senior Investor Relations Analyst
Telephone: (405) 228-4477
E-mail: scott.smalling@dvn.com

Shea Snyder
Senior Investor Relations Analyst
Telephone: (405) 552-4782
E-mail: shea.snyder@dvn.com

Media:
Brian Engel
Manager, Public Affairs
Telephone: (405) 228-7750
E-mail: brian.engel@dvn.com

Chip Minty
Senior External Communications Specialist
Telephone: (405) 228-8647
E-mail: chip.minty@dvn.com

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
Telephone: (405) 552-4570
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 8, 2005, on the Third Floor of the Bank One Center, 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 19,000 shareholders of record.

THE DEVON WEBSITE

To learn more about Devon Energy, visit our website at: **www.devonenergy.com**. Devon's website contains press releases, SEC filings, answers to commonly asked questions, stock quote information and more.