DEVON ENERGY CORP/DE
Form 10-K
February 28, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

(Mark One)

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended December 31, 2006**
	or
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number 001-32318

Devon Energy Corporation
(Exact name of Registrant as Specified in its Charter)

Delaware	**73-1567067**
(State or Other Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification No.)*
20 North Broadway, Oklahoma City, Oklahoma	**73102-8260**
(Address of Principal Executive Offices)	*(Zip Code)*

Registrant s telephone number, including area code:
(405) 235-3611

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.10 per share	The New York Stock Exchange
4.90% Exchangeable Debentures, due 2008	The New York Stock Exchange
4.95% Exchangeable Debentures, due 2008	The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer (as defined in Rule 405 of the Securities Act). Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

The aggregate market value of the voting stock held by non-affiliates of the registrant as of June 30, 2006, was $26,464,653,232.

On February 15, 2007, 444,461,491 shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 2007 annual meeting of stockholders Part III

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DEFINITIONS

As used in this document:

Bbl or Bbls means barrel or barrels.

Bcf means billion cubic feet.

Boe means barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas.

FPSO means floating, production, storage and offloading facilities.

Btu means British Thermal units, a measure of heating value.

Inside FERC refers to the publication *Inside F.E.R.C. s Gas Market Report.*

LIBOR means London Interbank Offered Rate.

MBbls means thousand barrels.

MMBbls means million barrels.

MBoe means thousand Boe.

MMBoe means million Boe.

MMBtu means million Btu.

Mcf means thousand cubic feet.

MMcf means million cubic feet.

NGL or NGLs means natural gas liquids.

NYMEX means New York Mercantile Exchange.

Oil includes crude oil and condensate.

SEC means United States Securities and Exchange Commission.

Domestic means the properties of Devon in the onshore continental United States and the offshore Gulf of Mexico.

U.S. Onshore means the properties of Devon in the continental United States.

U.S. Offshore means the properties of Devon in the Gulf of Mexico.

Canada means the division of Devon encompassing oil and gas properties located in Canada.

International means the division of Devon encompassing oil and gas properties that lie outside the United States and Canada.

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs and plans and objectives of management for future operations, are forward-looking statements. Such forward-looking statements are based on our examination of historical operating trends, the information which was used to prepare the December 31, 2006 reserve reports and other data in our possession or available from third parties. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as may, will, expect, intend, project, estimate, anticipate, believe, or continue or the negative thereof or variations thereon or similar

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terminology. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, our assumptions about:

- energy markets;
- production levels, including Canadian production subject to government royalties which fluctuate with prices and international production governed by payout agreements which affect reported production;
- reserve levels;
- competitive conditions;
- technology;
- the availability of capital resources;
- capital expenditure and other contractual obligations;
- the supply and demand for oil, natural gas, NGLs and other products or services;
- the price of oil, natural gas, NGLs and other products or services;
- currency exchange rates;
- the weather;
- inflation;
- the availability of goods and services;
- drilling risks;
- future processing volumes and pipeline throughput;
- general economic conditions, either internationally or nationally or in the jurisdictions in which we or our subsidiaries conduct business;
- legislative or regulatory changes, including retroactive royalty or production tax regimes, changes in environmental regulation, environmental risks and liability under federal, state and foreign environmental laws and regulations;
- terrorism;
- occurrence of property acquisitions or divestitures;
- the securities or capital markets; and

other factors disclosed under Item 2. Properties Proved Reserves and Estimated Future Net Revenue, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, Item 7A. Quantitative and Qualitative Disclosures About Market Risk and elsewhere in this report.

All subsequent written and oral forward-looking statements attributable to Devon, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements. We assume no duty to update or revise our forward-looking statements based on changes in internal estimates or expectations or otherwise.

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PART I

Item 1. *Business*

General

Devon Energy Corporation, including its subsidiaries, (Devon) is an independent energy company engaged primarily in oil and gas exploration, development and production, the transportation of oil, gas, and NGLs and the processing of natural gas. We own oil and gas properties principally in the United States and Canada and, to a lesser degree, various regions located outside North America, including Azerbaijan, Brazil and China. We also own properties in West Africa and Egypt that we intend to sell in 2007. In addition to our oil and gas operations, we have marketing and midstream operations primarily in North America. These include marketing natural gas, crude oil and NGLs, and constructing and operating pipelines, storage and treating facilities and gas processing plants. A detailed description of our significant properties and associated 2006 developments can be found under Item 2. Properties.

We began operations in 1971 as a privately held company. In 1988, our common stock began trading publicly on the American Stock Exchange under the symbol DVN. In October 2004, we transferred our common stock listing to the New York Stock Exchange. Our principal and administrative offices are located at 20 North Broadway, Oklahoma City, OK 73102-8260 (telephone 405/235-3611).

Strategy

We have a two-pronged operating strategy. First, we invest the vast majority of our capital budget in low-risk exploitation and development projects on our extensive North American property base which provides reliable and repeatable production and reserves additions. To supplement that strategy, we annually invest a measured amount of capital in high-impact, long cycle-time projects to replenish our development inventory for the future. The philosophy that underlies the execution of this strategy is to strive to increase value on a per share basis by:

- building oil and gas reserves and production;
- exercising capital discipline;
- preserving financial flexibility;
- maintaining a low unit-cost structure; and
- improving performance through our marketing and midstream operations.

Development of Business

During 1988, we expanded our capital base with our first issuance of common stock to the public. This transaction began a substantial expansion program that has continued through the subsequent years. This expansion is attributable to both a focused mergers and acquisitions program spanning a number of years and an active ongoing exploration and development drilling program. Total proved reserves increased from 8 MMBoe[1] at year-end 1987 to 2,376 MMBoe[2] at year-end 2006.

During the same time period, we have grown proved reserves from 0.66 Boe[1] per diluted share at the end of 1987 to 5.30 Boe[2] per diluted share at the end of 2006. This represents a compound annual growth rate of 12%. We have also increased production from 0.09 Boe[1] per diluted share in 1987 to 0.48 Boe[2] per diluted share in 2006, for a compound annual growth rate of 9%. This per share growth is a direct result of successful execution of our strategic plan and other key transactions and events.

[1] Excludes the effects of mergers in 1998 and 2000 that were accounted for as poolings of interests.
[2] Excludes reserves in Egypt that are held for sale and classified as discontinued operations as of December 31, 2006.

We achieved a number of significant accomplishments in our operations during 2006, including those discussed below.

Barnett Shale Expansion We dramatically increased our presence in the Barnett Shale area of north Texas in 2006 with our $2.2 billion acquisition of Chief Holdings LLC (Chief). The acquired properties included estimated proved reserves of approximately 600 Bcf of natural gas equivalent and leasehold totaling 169,000 net acres with some 2,000 additional drilling locations.

U.S. Onshore Production and Reserves Growth Our U.S. onshore properties, including the Barnett Shale and the Groesbeck and Carthage areas in east Texas, showed strong production growth in 2006. These three areas, which accounted for a little over one-half of our U.S. onshore production, had production growth in 2006 of 11% compared to 2005.

In addition to production growth, our U.S. onshore properties also demonstrated significant growth in proved reserves. U.S onshore production in 2006 of 110 MMBoe was more than offset by 265 MMBoe of additions from extensions and discoveries during the year, as well as 105 MMBoe added through acquisitions, primarily the Chief acquisition. The additional reserves added by drilling and acquisition activities caused our 2006 U.S. onshore proved reserves to increase 21% compared to the end of 2005.

Gulf of Mexico Exploration and Development We continued to achieve success in 2006 with our deepwater Gulf of Mexico exploration program. To date, we have drilled four discovery wells in the Lower Tertiary trend Cascade in 2002, St. Malo in 2003, Jack in 2004 and Kaskida in the third quarter of 2006. Also in the third quarter of 2006, we announced the successful production test of the Jack No. 2 well in the Lower Tertiary. These achievements support our positive view of the Lower Tertiary and demonstrate the growth potential of our high-impact exploration strategy on long-term production, reserves and value.

Specific Gulf of Mexico developments in 2006 included the following:

Along with our partners, we conducted a successful production test of the deepwater Jack No. 2 well in the Lower Tertiary trend. The successful production test was an important milestone in moving the Jack project, originally discovered in 2004, toward sanctioning and development. We have a 25% working interest in the Jack prospect.

Also in the Lower Tertiary trend, we increased our working interest in the Cascade project, discovered in 2002, from 25% to 50%. We and our partner plan to develop Cascade using an FPSO vessel. We anticipate first production from Cascade in late 2009.

Elsewhere in the Lower Tertiary, we and our partners announced an oil discovery on the Kaskida prospect. Kaskida is our fourth discovery in the Lower Tertiary trend and our first in the Keathley Canyon deepwater lease area. We have identified 19 additional exploratory prospects in the Lower Tertiary, and 12 of these prospects are on our Keathley Canyon acreage. We believe that Kaskida, in which we own a 20% working interest, is the largest of our four Lower Tertiary discoveries to date.

In addition to our Lower Tertiary success, we also announced a Miocene-aged oil discovery on the Mission Deep prospect in the fourth quarter of 2006. The well, in 7,300 feet of water, was drilled to 25,000 feet and encountered more than 250 feet of net oil pay. We have 15 additional prospects in our deepwater Miocene inventory. Our working interest in the Mission Deep prospect is 50%.

We secured long-term contracts for two deepwater drilling rigs in 2006. One of the rigs is scheduled for delivery in mid-2007, and the other is scheduled for delivery in mid-2008. With these two deepwater rigs under contract, we will have additional capacity and flexibility to test, appraise and develop multiple prospects in the Lower Tertiary and Miocene trends.

Jackfish During 2006, facilities construction and drilling continued at our 100% owned Jackfish thermal heavy oil project in Canada. We expect to commence steam injection at Jackfish in the second quarter of 2007, with estimated full production of 35,000 barrels of oil per day anticipated by the end of 2008.

Polvo Construction and fabrication for the Polvo oil development project offshore Brazil continued on schedule throughout 2006. We expect first production from Polvo in mid-2007. We operate Polvo with a 60% working interest.

On November 14, 2006, we announced our plans to divest our operations in Egypt. At December 31, 2006, our Egyptian operations had proved reserves of eight million Boe. Subsequently, on January 23, 2007, we announced our plans to divest our operations in West Africa, including Equatorial Guinea, Cote d Ivoire, and other countries in the region. At December 31, 2006, our West African operations had proved reserves of 90 million Boe. We anticipate completing the sale of our Egyptian operations in the first half of 2007 and our West African operations in the third quarter of 2007. Divesting these properties will allow us to redeploy our financial and intellectual capital to the significant growth opportunities we have developed onshore in North America and in the deepwater Gulf of Mexico. Additionally, we will sharpen our focus in North America and concentrate our international operations in Brazil and China, where we have established competitive advantages.

Pursuant to accounting rules for discontinued operations, our Egyptian operations were classified as discontinued operations at the end of 2006. Accordingly, we have classified all amounts related to our operations in Egypt as discontinued. Therefore, all amounts for all periods presented in this document related to our continuing operations exclude Egypt. Our West African operations did not meet the criteria to be considered discontinued operations at the end of 2006. Therefore, all amounts related to our operations in West Africa are still presented in this document as part of our continuing operations. Beginning in 2007, our operations in West Africa will be considered and classified as discontinued.

Financial Information about Segments and Geographical Areas

Notes 14 and 15 to the consolidated financial statements included in Item 8. Financial Statements and Supplementary Data of this report contain information on our segments and geographical areas.

Oil and Natural Gas Marketing

The spot market for oil and gas is subject to volatility as supply and demand factors fluctuate. We may periodically enter into financial hedging arrangements, fixed-price contracts or firm delivery commitments with a portion of our oil and gas production. These activities are intended to support targeted price levels and to manage our exposure to price fluctuations. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Oil Marketing

Our oil production is sold under both long-term (one year or more) and short-term (less than one year) agreements at prices negotiated with third parties. All of our oil production is sold at variable or market-sensitive prices.

Natural Gas Marketing

Our gas production is also sold under both long-term and short-term agreements at prices negotiated with third parties. Although exact percentages vary daily, as of February 2007, approximately 75% of our natural gas production was sold under short-term contracts at variable or market-sensitive prices. These market-sensitive sales are referred to as spot market sales. Another 23% of our production was committed under various long-term contracts which dedicate the natural gas to a purchaser for an extended period of time but still at market sensitive prices. Our remaining gas production was sold under long-term fixed price contracts.

Marketing and Midstream Activities

The primary objective of our marketing and midstream operations is to add value to us and other producers to whom we provide such services by gathering, processing and marketing oil and gas production in a timely and efficient manner. Our most significant marketing and midstream asset is the Bridgeport processing plant and gathering system located in North Texas. These facilities serve not only our gas production from the Barnett Shale but also gas production of other producers in the area.

Our marketing and midstream revenues are primarily generated by:

- selling NGLs that are either extracted from the gas streams processed by our plants or purchased from third parties for marketing, and
- selling or gathering gas that moves through our transport pipelines and unrelated third party pipelines.

Our marketing and midstream costs and expenses are primarily incurred from:

- purchasing the gas streams entering our transport pipelines and plants;
- purchasing fuel needed to operate our plants, compressors and related pipeline facilities;
- purchasing third-party NGLs;
- operating our plants, gathering systems and related facilities; and
- transporting products on unrelated third-party pipelines.

Customers

We sell our gas production to a variety of customers including pipelines, utilities, gas marketing firms, industrial users and local distribution companies. Existing gathering systems and interstate and intrastate pipelines are used to consummate gas sales and deliveries.

The principal customers for our crude oil production are refiners, remarketers and other companies, some of which have pipeline facilities near the producing properties. In the event pipeline facilities are not conveniently available, crude oil is trucked or shipped to storage, refining or pipeline facilities.

During 2006, revenues received from ExxonMobil and its affiliates were $1.1 billion, or 10% of our consolidated revenues. No purchaser accounted for over 10% of our revenues in 2005 or 2004.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations.

Government Regulation

The oil and gas industry is subject to various types of regulation throughout the world. Legislation affecting the oil and gas industry has been pervasive and is under constant review for amendment or expansion. Pursuant to such legislation, numerous government agencies have issued extensive laws and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Such laws and regulations have a significant impact on oil and gas exploration, production and marketing and midstream activities. These laws and regulations increase the cost of doing business and, consequently, affect profitability. Inasmuch as new legislation affecting the oil and gas industry is commonplace and existing laws and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws and regulations. However, we do not expect that any of these laws and regulations will affect our operations in a manner materially different than they would affect other oil and gas companies of similar size.

The following are significant areas of government control and regulation in the United States, Canada and other international locations in which we operate.

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Exploration and Production Regulation

Our oil and gas operations are subject to various federal, state, provincial, local and international laws and regulations, including regulations related to the acquisition of seismic data; the location of wells; drilling and casing of wells; well production; spill prevention plans; the use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations; surface usage and the restoration of properties upon which wells have been drilled; the calculation and disbursement of royalty payments and production taxes; the plugging and abandoning of wells; the transportation of production; and, in international operations, minimum investments in the country of operations.

Our operations are also subject to conservation regulations, including the regulation of the size of drilling and spacing units or proration units; the number of wells which may be drilled in a unit; the rate of production allowable from oil and natural gas wells; and the unitization or pooling of oil and natural gas properties. In the United States, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases, which may make it more difficult to develop oil and gas properties. In addition, state conservation laws generally limit the venting or flaring of natural gas and impose certain requirements regarding the ratable purchase of production. The effect of these regulations is to limit the amounts of oil and natural gas we can produce from our wells and to limit the number of wells or the locations at which we can drill.

Certain of our U.S. oil and natural gas leases are granted by the federal government and administered by various federal agencies, including the Bureau of Land Management and the Minerals Management Service (MMS) of the Department of the Interior. Such leases require compliance with detailed federal regulations and orders that regulate, among other matters, drilling and operations on lands covered by these leases, and calculation and disbursement of royalty payments to the federal government. The MMS has been particularly active in recent years in evaluating and, in some cases, promulgating new rules and regulations regarding competitive lease bidding and royalty payment obligations for production from federal lands. The Federal Energy Regulatory Commission also has jurisdiction over certain U.S. offshore activities pursuant to the Outer Continental Shelf Lands Act.

Royalties and Incentives in Canada

The royalty system in Canada is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the parties. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, with the royalty rate dependent in part upon prescribed reference prices, well productivity, geographical location, field discovery date and the type and quality of the petroleum product produced. From time to time, the federal and provincial governments of Canada have also established incentive programs such as royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and gas exploration or enhanced recovery projects. These incentives generally have the effect of increasing our revenues, earnings and cash flow.

Pricing and Marketing in Canada

An order from Canada s National Energy Board (NEB) is required for oil and natural gas exports from Canada. Any oil or natural gas export to be made pursuant to an export contract of a certain duration or covering a certain quantity requires an exporter to obtain an export license from the NEB, which requires the approval of the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts meet certain criteria prescribed by the NEB. The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

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Investment Canada Act

The Investment Canada Act requires Government of Canada approval, in certain cases, of the acquisition of control of a Canadian business by an entity that is not controlled by Canadians. In certain circumstances, the acquisition of natural resource properties may be considered to be a transaction requiring such approval.

Production Sharing Contracts

Many of our international licenses are governed by Production Sharing Contracts (PSCs) between the concessionaires and the granting government agency. PSCs are contracts that define and regulate the framework for investments, revenue sharing, and taxation of mineral interests in foreign countries. Unlike most domestic leases, PSCs have defined production terms and time limits of generally 30 years. PSCs also generally contain sliding scale revenue sharing provisions. As a result, at either higher production rates or higher cumulative rates of return, PSCs generally allow the government partner to retain higher fractions of revenue.

Environmental and Occupational Regulations

We are subject to various federal, state, provincial, local and international laws and regulations concerning occupational safety and health and the discharge of materials into, and the protection of, the environment. Environmental laws and regulations relate to, among other things, assessing the environmental impact of seismic acquisition, drilling or construction activities; the generation, storage, transportation and disposal of waste materials; the monitoring, abandonment, reclamation and remediation of well and other sites, including sites of former operations; and the development of emergency response and spill contingency plans. The application of worldwide standards, such as ISO 14000 governing Environmental Management Systems, are required to be implemented for some international oil and gas operations.

In 1997, numerous countries participated in an international conference under the United Nations Framework Convention on Climate Change and adopted an agreement known as the Kyoto Protocol (the Protocol). The Protocol became effective February 14, 2005, and requires reductions of certain emissions that contribute to atmospheric levels of greenhouse gases. Certain countries in which we operate (but not the United States) have ratified the Protocol. Presently, it is not possible to accurately estimate the costs we could incur to comply with any laws or regulations developed to achieve such emissions reductions, but such expenditures could be substantial. In 2006, Devon published its Corporate Climate Change Position and Strategy. Key components of the strategy include initiation of energy conservation measures, tracking emerging climate changes legislation and publication of a corporate greenhouse gas emission inventory by the end of 2007. All provisions of the strategy are in progress.

We consider the costs of environmental protection and safety and health compliance necessary and manageable parts of our business. With the efforts of our Environmental, Health and Safety Department, we have been able to plan for and comply with environmental and safety and health initiatives without materially altering our operating strategy. We anticipate making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. While our unreimbursed expenditures in 2006 concerning such matters were immaterial, we cannot predict with any reasonable degree of certainty our future exposure concerning such matters.

We maintain levels of insurance customary in the industry to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of oil, salt water or other substances. However, we do not maintain 100% coverage concerning any environmental claim, and no coverage is maintained with respect to any penalty or fine required to be paid because of a violation of law.

Employees

As of December 31, 2006, we had approximately 4,600 employees. We consider labor relations with our employees to be satisfactory. We have not had any work stoppages or strikes pertaining to our employees.

Competition

See Item 1A. Risk Factors.

Availability of Reports

Through our website, http://www.devonenergy.com, we make available electronic copies of the charters of the committees of our Board of Directors, other documents related to Devon s corporate governance (including our Code of Ethics for the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer), and documents Devon files or furnishes to the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, as well as any amendments to these reports. Access to these electronic filings is available free of charge as soon as reasonably practicable after filing or furnishing them to the SEC. Printed copies of our committee charters or other governance documents and filings can be requested by writing to our corporate secretary at the address on the cover of this report.

Item 1A. *Risk Factors*

Our business activities, and the oil and gas industry in general, are subject to a variety of risks. Although we have a diversified asset base, a strong balance sheet and a history of generating sufficient cash to fund capital expenditure and investment programs and to pay dividends, if any of the following risk factors should occur, our profitability, financial condition and/or liquidity could be materially impacted. As a result, holders of our securities could lose part or all of their investment in Devon.

Oil, Natural Gas and NGL Prices are Volatile

Our financial results are highly dependent on the prices of and demand for oil, natural gas and NGLs. A significant downward movement of the prices for these commodities could have a material adverse effect on our estimated proved reserves, revenues and operating cash flows, as well as the level of planned drilling activities. Such a downward price movement could also have a material adverse effect on our profitability, the carrying value of our oil and gas properties and future growth. Historically, prices have been volatile and are likely to continue to be volatile in the future due to numerous factors beyond our control. These factors include, but are not limited to:

- consumer demand for oil, natural gas and NGLs;
- conservation efforts;
- OPEC production restraints;
- weather;
- regional market pricing differences;
- differing quality of oil produced (i.e., sweet crude versus heavy or sour crude) and Btu content of gas produced;
- the level of imports and exports of oil, natural gas and NGLs;
- the price and availability of alternative fuels;

the overall economic environment; and

governmental regulations and taxes.

Estimates of Oil, Natural Gas and NGL Reserves are Uncertain

The process of estimating oil, gas and NGL reserves is complex and requires significant judgment in the evaluation of available geological, engineering and economic data for each reservoir, particularly for new discoveries. Because of the high degree of judgment involved, different reserve engineers may develop different estimates of reserve quantities and related revenue based on the same data. In addition, the reserve

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estimates for a given reservoir may change substantially over time as a result of several factors including additional development activity, the viability of production under varying economic conditions and variations in production levels and associated costs. Consequently, material revisions to existing reserve estimates may occur as a result of changes in any of these factors. Such revisions to proved reserves could have a material adverse effect on our estimates of future net revenue, as well as our financial condition and profitability. Additional discussion of our policies regarding estimating and recording reserves is described in Item 2. Properties Proved Reserves and Estimated Future Net Revenue.

Discoveries or Acquisitions of Additional Reserves are Needed to Avoid a Material Decline in Reserves and Production

The production rate from oil and gas properties generally declines as reserves are depleted, while related per unit production costs generally increase due to decreasing reservoir pressures and other factors. Therefore, our estimated proved reserves and future oil, gas and NGL production will decline materially as reserves are produced unless we conduct successful exploration and development activities or, through engineering studies, identify additional producing zones in existing wells, secondary recovery reserves or tertiary recovery reserves, or acquire additional properties containing proved reserves. Consequently, our future oil, gas and NGL production and related per unit production costs are highly dependent upon our level of success in finding or acquiring additional reserves.

Future Exploration and Drilling Results are Uncertain and Involve Substantial Costs

Substantial costs are often required to locate and acquire properties and drill exploratory wells. Such activities are subject to numerous risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. The costs of drilling and completing wells are often uncertain. In addition, oil and gas properties can become damaged or drilling operations may be curtailed, delayed or canceled as a result of a variety of factors including, but not limited to:

- unexpected drilling conditions;
- pressure or irregularities in reservoir formations;
- equipment failures or accidents;
- fires, explosions, blowouts and surface cratering;
- marine risks such as capsizing, collisions and hurricanes;
- other adverse weather conditions;
- lack of access to pipelines or other methods of transportation;
- environmental hazards or liabilities; and
- shortages or delays in the delivery of equipment.

A significant occurrence of one of these factors could result in a partial or total loss of our investment in a particular property. In addition, drilling activities may not be successful in establishing proved reserves. Such a failure could have an adverse effect on our future results of operations and financial condition. While both exploratory and developmental drilling activities involve these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. We are currently performing exploratory drilling activities in certain international countries. We have been granted drilling concessions in these countries that require commitments on our behalf to incur capital expenditures. Even if future drilling activities are unsuccessful in establishing proved reserves, we will likely be required to fulfill our commitments to make such capital expenditures.

Industry Competition For Leases, Materials, People and Capital Can Be Significant

Strong competition exists in all sectors of the oil and gas industry. We compete with major integrated and other independent oil and gas companies for the acquisition of oil and gas leases and properties. We also compete for the equipment and personnel required to explore, develop and operate properties. Competition is also prevalent in the marketing of oil, gas and NGLs. Higher recent commodity prices have increased drilling and operating costs of existing properties. Higher prices have also increased the costs of properties available for acquisition, and there are a greater number of publicly traded companies and private-equity firms with the financial resources to pursue acquisition opportunities. Certain of our competitors have financial and other resources substantially larger than ours, and they have also established strategic long-term positions and maintain strong governmental relationships in countries in which we may seek new entry. As a consequence, we may be at a competitive disadvantage in bidding for drilling rights. In addition, many of our larger competitors may have a competitive advantage when responding to factors that affect demand for oil and natural gas production, such as changing worldwide prices and levels of production, the cost and availability of alternative fuels and the application of government regulations.

International Operations Have Uncertain Political, Economic and Other Risks

Our operations outside North America are based primarily in Azerbaijan, Brazil, China and various countries in West Africa. As a result, we face political and economic risks and other uncertainties that are less prevalent for our operations in North America. Such factors include, but are not limited to:

- general strikes and civil unrest;
- the risk of war, acts of terrorism, expropriation, forced renegotiation or modification of existing contracts;
- import and export regulations;
- taxation policies, including royalty and tax increases and retroactive tax claims, and investment restrictions;
- transportation regulations and tariffs;
- exchange controls, currency fluctuations, devaluation or other activities that limit or disrupt markets and restrict payments or the movement of funds;
- laws and policies of the United States affecting foreign trade, including trade sanctions;
- the possibility of being subject to exclusive jurisdiction of foreign courts in connection with legal disputes relating to licenses to operate and concession rights in countries where we currently operate;
- the possible inability to subject foreign persons to the jurisdiction of courts in the United States; and
- difficulties in enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations.

Foreign countries have occasionally asserted rights to oil and gas properties through border disputes. If a country claims superior rights to oil and gas leases or concessions granted to us by another country, our interests could decrease in value or be lost. Even our smaller international assets may affect our overall business and results of operations by distracting management s attention from our more significant assets. Various regions of the world have a history of political and economic instability. This instability could result in new governments or the adoption of new policies that might result in a substantially more hostile attitude toward foreign investment. In an extreme case, such a change could result in termination of contract rights and expropriation of foreign-owned assets. This could adversely affect our interests and our future profitability.

The impact that future terrorist attacks or regional hostilities may have on the oil and gas industry in general, and on our operations in particular, is not known at this time. Uncertainty surrounding military strikes or a sustained military campaign may affect operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or indirect casualties of, an act of terror or war. We may be required to incur significant costs in the future to safeguard our assets against terrorist activities.

Government Laws and Regulations Can Change

Our operations are subject to federal laws and regulations in the United States, Canada and the other international countries in which we operate. In addition, we are also subject to the laws and regulations of various states, provinces and local governments. Pursuant to such legislation, numerous government departments and agencies have issued extensive rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Changes in such legislation have affected, and at times in the future could affect, our future operations. Political developments can restrict production levels, enact price controls, change environmental protection requirements, and increase taxes, royalties and other amounts payable to governments or governmental agencies. Although we are unable to predict changes to existing laws and regulations, such changes could significantly impact our profitability. While such legislation can change at any time in the future, those laws and regulations outside North America to which we are subject generally include greater risk of unforeseen change.

Environmental Matters and Costs Can Be Significant

As an owner or lessee and operator of oil and gas properties, we are subject to various federal, state, provincial, local and international laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on us for the cost of pollution clean-up resulting from our operations in affected areas. Any future environmental costs of fulfilling our commitments to the environment are uncertain and will be governed by several factors, including future changes to regulatory requirements. There is no assurance that changes in or additions to laws or regulations regarding the protection of the environment will not have a significant impact on our operations and profitability.

Insurance Does Not Cover All Risks

Exploration, development, production and processing of oil, natural gas and NGLs can be hazardous and involve unforeseen occurrences such as hurricanes, blowouts, cratering, fires and loss of well control. These occurrences can result in damage to or destruction of wells or production facilities, injury to persons, loss of life, or damage to property or the environment. We maintain insurance against certain losses or liabilities in accordance with customary industry practices and in amounts that management believes to be prudent. However, insurance against all operational risks is not available to us. Due to changes in the marketplace following the 2005 hurricanes in the Gulf of Mexico, we currently have only a *de minimis* amount of coverage for any damage that may be caused by future named windstorms in the Gulf of Mexico.

Item 1B. *Unresolved Staff Comments*

Not applicable.

Item 2. *Properties*

Substantially all of our properties consist of interests in developed and undeveloped oil and gas leases and mineral acreage located in our core operating areas. These interests entitle us to drill for and produce oil, natural gas and NGLs from specific areas. Our interests are mostly in the form of working interests and, to a lesser extent, overriding royalty, mineral and net profits interests, foreign government concessions and other forms of direct and indirect ownership in oil and gas properties.

We also have certain midstream assets, including natural gas and NGL processing plants and pipeline systems. Our most significant midstream assets are our assets serving the Barnett Shale region in North Texas. These assets include approximately 2,700 miles of pipeline, two gas processing plants with 680 MMcf per day of total capacity, and a 15 MBbls per day NGL fractionator.

Proved Reserves and Estimated Future Net Revenue

The SEC defines proved oil and gas reserves as the estimated quantities of crude oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

The process of estimating oil, gas and NGL reserves is complex and requires significant judgment as discussed in Item 1A. Risk Factors. As a result, we have developed internal policies for estimating and recording reserves. Our policies regarding booking reserves require proved reserves to be in compliance with the SEC definitions and guidance, and assign responsibilities for reserves bookings to our Reserve Evaluation Group (the Group). Our policies also require that reserve estimates be made by qualified reserves estimators (QREs), as defined by the Society of Petroleum Engineers standards. A list of our QREs is kept by the Senior Advisor Corporate Reserves. All QREs are required to receive education covering the fundamentals of SEC proved reserves assignments.

The Group is responsible for internal reserves evaluation and certification and includes the Manager E&P Budgets and Reserves and the Senior Advisor Corporate Reserves. The Group reports independently of any of our operating divisions. The Vice President Planning and Evaluation is directly responsible for overseeing the Group and reports to the President of Devon. No portion of the Group s compensation is dependent on the quantity of reserves booked.

Throughout the year, the Group performs internal audits of each operating division s reserves. Selection criteria of reserves that are audited include major fields and major additions and revisions to reserves. In addition, the Group reviews reserve estimates with each of the third-party petroleum consultants discussed below.

In addition to internal audits, we engage three independent petroleum consulting firms to both prepare and audit a significant portion of our proved reserves. Ryder Scott Company, L.P. prepared the 2006 reserves estimates for all our offshore Gulf of Mexico properties and for 99% of our International proved reserves. LaRoche Petroleum Consultants, Ltd. audited the 2006 reserves estimates for 87% of our domestic onshore properties. AJM Petroleum Consultants prepared estimates covering 46% of our 2006 Canadian reserves and audited an additional 39% of our Canadian 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 2006, 2005 and 2004.

	2006		2005		2004	
	Prepared	**Audited**	**Prepared**	**Audited**	**Prepared**	**Audited**
U.S.	7%	81%	9%	79%	16%	61%
Canada	46%	39%	46%	26%	22%	
International	99%		98%		98%	
Total	28%	61%	31%	54%	28%	35%

Prepared reserves are those quantities of reserves which were prepared by an independent petroleum consultant. Audited reserves are those quantities of reserves which were estimated by our 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.

In addition to internal and external reviews, three independent members of our Board of Directors have been assigned to a Reserves Committee. The Reserves Committee meets at lease twice a year to discuss reserves issues and policies and periodically meets separately with our senior reserves engineering personnel and our independent petroleum consultants. The Reserves Committee assists the Board of Directors with the oversight of the following:

- the annual review and evaluation of our consolidated oil, gas and NGL reserves;
- the integrity of our reserves evaluation and reporting system;
- our compliance with legal and regulatory requirements related to reserves evaluation, preparation, and disclosure;
- the qualifications and independence of our independent engineering consultants; and
- our business practices and ethical standards in relation to the preparation and disclosure of reserves.

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The following table sets forth our estimated proved reserves and the related estimated pre-tax future net revenues, pre-tax 10% present value and after-tax standardized measure of discounted future net cash flows as of December 31, 2006. These estimates correspond with the method used in presenting the Supplemental Information on Oil and Gas Operations in Note 15 to our consolidated financial statements included herein.

	Total Proved Reserves	Proved Developed Reserves	Proved Undeveloped Reserves
Total Reserves			
Oil (MMBbls)	708	358	350
Gas (Bcf)	8,356	6,518	1,838
NGLs (MMBbls)	275	229	46
MMBoe(1)	2,376	1,674	702
Pre-tax future net revenue (in millions)(2)	$ 44,428	32,471	11,957
Pre-tax 10% present value (in millions)(2)	$ 24,095	19,168	4,927
Standardized measure of discounted future net cash flows (in millions)(2)(3)	$ 16,573		
U.S. Reserves			
Oil (MMBbls)	170	147	23
Gas (Bcf)	6,355	4,916	1,439
NGLs (MMBbls)	233	196	37
MMBoe(1)	1,462	1,163	299
Pre-tax future net revenue (in millions)(2)	$ 24,203	20,504	3,699
Pre-tax 10% present value (in millions)(2)	$ 12,639	11,503	1,136
Standardized measure of discounted future net cash flows (in millions)(2)(3)	$ 8,677		
Canadian Reserves			
Oil (MMBbls)	329	112	217
Gas (Bcf)	1,896	1,560	336
NGLs (MMBbls)	42	33	9
MMBoe(1)	687	405	282
Pre-tax future net revenue (in millions)(2)	$ 12,749	8,499	4,250
Pre-tax 10% present value (in millions)(2)	$ 6,714	4,872	1,842
Standardized measure of discounted future net cash flows (in millions)(2)(3)	$ 4,817		
International Reserves			
Oil (MMBbls)	209	99	110
Gas (Bcf)	105	42	63
NGLs (MMBbls)			
MMBoe(1)	227	106	121
Pre-tax future net revenue (in millions)(2)	$ 7,476	3,468	4,008
Pre-tax 10% present value (in millions)(2)	$ 4,742	2,793	1,949
Standardized measure of discounted future net cash flows (in millions)(2)(3)	$ 3,079		

(1) Gas reserves are converted to Boe at the rate of six Mcf per Bbl of oil, based upon the approximate relative energy content of natural gas to oil, which rate is not necessarily indicative of the relationship of gas to oil prices. NGL reserves are converted to Boe on a one-to-one basis with oil.

(2) Estimated pre-tax future net revenue represents estimated future revenue to be generated from the production of proved reserves, net of estimated production and development costs and site restoration and abandonment charges. The amounts shown do not give effect to non-property related expenses such as debt service and future income tax expense or to depreciation, depletion and amortization.

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These amounts were calculated using prices and costs in effect for each individual property as of December 31, 2006. These prices were not changed except where different prices were fixed and determinable from applicable contracts. These assumptions yield average prices over the life of our properties of $46.11 per Bbl of oil, $5.06 per Mcf of natural gas and $27.63 per Bbl of NGLs. These prices compare to the December 31, 2006, NYMEX cash price of $61.05 per Bbl for crude oil and the Henry Hub spot price of $5.64 per MMBtu for natural gas.

The present value of after-tax future net revenues discounted at 10% per annum (standardized measure) was $16.6 billion at the end of 2006. Included as part of standardized measure were discounted future income taxes of $7.5 billion. Excluding these taxes, the present value of our pre-tax future net revenue (pre-tax 10% present value) was $24.1 billion. We believe the pre-tax 10% present value is a useful measure in addition to the after-tax standardized measure. The pre-tax 10% present value 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 standardized measure is dependent on the unique tax situation of each individual company, while the pre-tax 10% present value is based on prices and discount factors which are more consistent from company to company. We also understand that securities analysts use the pre-tax 10% present value measure in similar ways.

(3) See Note 15 to the consolidated financial statements included in Item 8. Financial Statements and Supplementary Data.

As presented in the previous table, we had 1,674 MMBoe of proved developed reserves at December 31, 2006. Proved developed reserves consist of proved developed producing reserves and proved developed non-producing reserves. The following table provides additional information regarding our proved developed reserves at December 31, 2006.

	Total Proved Developed Reserves	**Proved Developed Producing Reserves**	**Proved Developed Non-Producing Reserves**
Total Reserves			
Oil (MMBbls)	358	298	60
Gas (Bcf)	6,518	5,784	734
NGLs (MMBbls)	229	208	21
MMBoe	1,674	1,470	204
U.S. Reserves			
Oil (MMBbls)	147	123	24
Gas (Bcf)	4,916	4,337	579
NGLs (MMBbls)	196	178	18
MMBoe	1,163	1,024	139
Canadian Reserves			
Oil (MMBbls)	112	93	19
Gas (Bcf)	1,560	1,410	150
NGLs (MMBbls)	33	30	3
MMBoe	405	358	47
International Reserves			
Oil (MMBbls)	99	82	17
Gas (Bcf)	42	37	5
NGLs (MMBbls)			

MMBoe	106	88	18

No estimates of our proved reserves have been filed with or included in reports to any federal or foreign governmental authority or agency since the beginning of the last fiscal year except in filings with the SEC and

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the Department of Energy (DOE). Reserve estimates filed with the SEC correspond with the estimates of our reserves contained herein. Reserve estimates filed with the DOE are based upon the same underlying technical and economic assumptions as the estimates of our reserves included herein. However, the DOE requires reports to include the interests of all owners in wells that we operate and to exclude all interests in wells that we do not operate.

The prices used in calculating the estimated future net revenues attributable to proved reserves do not necessarily reflect market prices for oil, gas and NGL production subsequent to December 31, 2006. There can be no assurance that all of the proved reserves will be produced and sold within the periods indicated, that the assumed prices will be realized or that existing contracts will be honored or judicially enforced.

Production, Revenue and Price History

Certain information concerning oil, natural gas and NGL production, prices, revenues (net of all royalties, overriding royalties and other third party interests) and operating expenses for the three years ended December 31, 2006, is set forth in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

Drilling Activities

The following tables summarize the results of our development and exploratory drilling activity for the past three years. The tables do not include our Egyptian operations that were classified as discontinued at the end of 2006.

Development Well Activity

	Wells Drilling at December 31, 2006		Net Wells Completed(2)					
			2006		2005		2004	
	Gross(1)	Net(2)	Productive	Dry	Productive	Dry	Productive	Dry
U.S.	210	151.4	877.1	12.5	782.3	8.2	719.4	11.7
Canada	12	7.1	593.2	3.3	546.8	5.2	413.2	17.7
International	20	2.3	8.5		10.3		22.5	
Total	242	160.8	1,478.8	15.8	1,339.4	13.4	1,155.1	29.4

Exploratory Well Activity

	Wells Drilling at December 31, 2006		Net Wells Completed(2)					
			2006		2005		2004	
	Gross(1)	Net(2)	Productive	Dry	Productive	Dry	Productive	Dry
U.S.	28	10.1	24.5	10.3	18.6	6.5	11.2	6.8
Canada	8	5.3	82.1	1.0	144.2	12.4	145.7	12.1
International	7	3.4		2.1	0.5	3.3	0.5	0.4

Total	43	18.8	106.6	13.4	163.3	22.2	157.4	19.3

(1) Gross wells are the sum of all wells in which we own an interest.

(2) Net wells are gross wells multiplied by our fractional working interests therein.

For the wells being drilled as of December 31, 2006 presented in the tables above, the following table summarizes the results of such wells as of February 1, 2007.

	Productive		Dry		Still in Progress	
	Gross	Net	Gross	Net	Gross	Net
U.S.	92	59.7	4	2.2	142	99.6
Canada	14	7.6			6	4.8
International	2	0.1			25	5.6
Total	108	67.4	4	2.2	173	110.0

Well Statistics

The following table sets forth our producing wells as of December 31, 2006. The table does not include our Egyptian operations that were classified as discontinued at the end of 2006.

	Oil Wells		Gas Wells		Total Wells	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
U.S.						
Onshore	8,494	2,751	16,588	11,415	25,082	14,166
Offshore	452	316	235	151	687	467
Total U.S.	8,946	3,067	16,823	11,566	25,769	14,633
Canada	2,885	1,983	4,506	2,569	7,391	4,552
International	526	217	4	2	530	219
Grand Total	12,357	5,267	21,333	14,137	33,690	19,404

(1) Gross wells are the total number of wells in which we own a working interest.

(2) Net wells are gross wells multiplied by our fractional working interests therein.

Developed and Undeveloped Acreage

The following table sets forth our developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2006. The table does not include our Egyptian operations that were classified as discontinued at the end of 2006.

	Developed		Undeveloped	
	Gross(1)	Net(2)	Gross(1)	Net(2)

		(In thousands)		
U.S.				
Onshore	3,364	2,162	5,893	3,026
Offshore	416	223	3,125	1,499
Total U.S.	3,780	2,385	9,018	4,525
Canada	3,392	2,124	10,257	6,304
International	552	299	15,222	9,440
Grand Total	7,724	4,808	34,497	20,269

(1) Gross acres are the total number of acres in which we own a working interest.

(2) Net acres are gross acres multiplied by our fractional working interests therein.

Operation of Properties

The day-to-day operations of oil and gas properties are the responsibility of an operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs field personnel and performs other functions.

We are the operator of 22,434 of our wells. As operator, we receive reimbursement for direct expenses incurred in the performance of our duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged in the area. In presenting our financial data, we record the monthly overhead reimbursements as a reduction of general and administrative expense, which is a common industry practice.

Organization Structure and Property Profiles

Our properties are located within the U.S. onshore and offshore regions, Canada, and certain locations outside North America. The following table presents proved reserve information for our significant properties as of December 31, 2006, along with their production volumes for the year 2006. Included in the table are certain U.S. offshore properties which currently have no proved reserves or production. Such properties are considered significant because they may be the source of significant growth in proved reserves and production in the future. Also included in the table are properties located in West Africa that we intend to sale in 2007. The table does not include our Egyptian operations that were classified as discontinued at the end of 2006. Additional summary profile information for our significant properties is provided following the table.

	Proved Reserves (MMBoe)(1)	Proved Reserves %(2)	Production (MMBoe)(1)	Production %(2)
U.S.				
Barnett Shale	608	25.6%	38	17.7%
Carthage	161	6.8%	14	6.6%
Permian Basin, Texas	111	4.7%	9	4.2%
Washakie	104	4.4%	6	2.6%
Groesbeck	65	2.7%	5	3.0%
Permian Basin, New Mexico	44	1.9%	6	3.2%
Other U.S. Onshore	260	10.9%	32	14.3%
Total U.S. Onshore	1,353	57.0%	110	51.6%
Deepwater Producing	67	2.8%	14	6.5%
Deepwater Development				
Deepwater Exploration				
Other U.S. Offshore	42	1.8%	8	3.8%
Total U.S. Offshore	109	4.6%	22	10.3%
Total U.S.	1,462	61.6%	132	61.9%
Canada				
Jackfish	186	7.8%		
Deep Basin	97	4.1%	12	5.5%
Lloydminster	84	3.6%	9	4.1%
Peace River Arch	75	3.1%	8	3.6%
Northeast British Columbia	59	2.5%	9	4.1%
Other Canada	186	7.8%	20	9.6%

Total Canada	687	28.9%	58	26.9%
International				
Azerbaijan	84	3.5%	4	1.7%
China	17	0.7%	4	2.1%
Brazil	9	0.4%		
Other	27	1.1%	2	0.9%
Assets to be sold in 2007(3):				
Equatorial Guinea	67	2.8%	11	5.2%
Other West Africa assets	23	1.0%	3	1.3
Total International	227	9.5%	24	11.2%
Grand Total	2,376	100.0%	214	100.0%

(1) Gas reserves and production are converted to Boe at the rate of six Mcf of gas per Bbl of oil, based upon the approximate relative energy content of natural gas to oil, which rate is not necessarily indicative of the relationship of gas to oil prices. NGL reserves and production are converted to Boe on a one-to-one basis with oil.

(2) Percentage of proved reserves and production the property bears to total proved reserves and production based on actual figures and not the rounded figures included in this table.

(3) In January 2007, we announced our plans to sell our assets in West Africa.

U.S. Onshore

Barnett Shale The Barnett Shale, located in north central Texas, is our largest property both in terms of production and proved reserves. Our leases include approximately 725,000 net acres located primarily in Denton, Johnson, Parker, Tarrant and Wise counties. The Barnett Shale is a non-conventional reservoir and it produces natural gas and natural gas liquids. We have an average working interest in the Barnett Shale of greater than 90%.

During 2006, we acquired additional Barnett Shale assets from Chief. The Chief acquisition added approximately 100 MMBoe of proved reserves, 169,000 net acres and some 2,000 additional drilling locations to our Barnett Shale holdings. We drilled 383 gross wells in the Barnett Shale in 2006 and expect to drill 385 gross wells in the area in 2007.

Carthage The Carthage area in east Texas includes primarily Harrison, Marion, Panola and Shelby counties. We hold approximately 126,000 net acres in the area. Our Carthage area wells produce primarily natural gas and natural gas liquids from conventional reservoirs. Our average working interest in this area is about 85%. We drilled 122 gross wells at Carthage in 2006 and plan to drill 150 gross wells in the area in 2007.

Permian Basin, Texas Our oil and gas properties in the Permian Basin of west Texas comprise approximately 1.2 million net acres. Our acreage is located primarily in Andrews, Crane, Martin, Terry, Ward and Yoakum counties. The Permian Basin produces both oil and natural gas from conventional reservoirs. Our average working interest in these properties is about 40%. We drilled 95 gross wells in the Permian Basin of west Texas in 2006, and we plan to drill another 100 gross wells in the area in 2007.

Washakie Our Washakie area leases are concentrated in Carbon and Sweetwater counties in southern Wyoming. We hold about 157,000 net acres in the Washakie area. Washakie produces primarily natural gas from conventional reservoirs. Our average working interest in the Washakie area is about 76%. In 2006, we drilled 137 wells at Washakie, and we plan to drill another 105 wells in the area in 2007.

Groesbeck The Groesbeck area of east Texas includes portions of Freestone, Leon, Limestone and Robertson counties. We hold about 173,000 net acres of land in the Groesbeck area. Groesbeck produces primarily natural gas from conventional reservoirs. Our average working interest in the area is approximately 72%. In 2006, we drilled 31 gross wells in the area. Our plans anticipate drilling 34 additional gross wells in the Groesbeck area in 2007.

Permian Basin, New Mexico We also own oil and gas properties in the Permian Basin in south eastern New Mexico. We hold about 342,000 net acres concentrated in Eddy and Lea counties. We produce conventional oil and natural gas from the Permian Basin in New Mexico, and have an average working interest of about 75% in these properties. In 2006, we drilled 82 gross wells in this area, and we expect to drill another 44 gross wells in 2007.

U.S. Offshore

Deepwater Producing Our assets in the Gulf of Mexico include four significant producing properties located in deep water (greater than 600 feet). These properties are Magnolia, Nansen, Red Hawk and Zia. They are all located on federal leases and total approximately 48,000 net acres. The properties produce both crude oil and natural gas. Our working interest is 65% in Zia and 50% in each of the other three properties.

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We drilled a total of two gross deepwater producing wells in 2006 and expect to drill four additional gross wells in 2007.

Deepwater Development In addition to our four significant deepwater producing properties, we are in the process of developing two other deepwater projects, Merganser and Cascade. Merganser and Cascade are located on federal leases encompassing a total of approximately 11,500 net acres. We have 50% working interests in both properties.

We drilled two producing wells at Merganser in 2006. These wells are expected to commence producing natural gas in mid-2007. No additional drilling is planned at Merganser.

We announced in 2006 our plans to develop the 2002 Cascade discovery using an FPSO vessel. Cascade is expected to begin producing primarily oil in late 2009. Additional drilling at Cascade is in the planning stage.

Deepwater Exploration Our exploration program in the Gulf of Mexico is focused primarily on deepwater opportunities. Our deepwater exploratory prospects include Miocene-aged objectives (five million to 24 million years) and older and deeper Lower Tertiary objectives. We hold federal leases comprising approximately 1.2 million net acres in our deepwater exploration inventory.

In 2006, various drilling and testing operations provided evidence that our Lower Tertiary properties may be a source of meaningful reserve and production growth in the future. Prior to 2006, we had drilled three discovery wells in the Lower Tertiary. These include Cascade in 2002 (see Deepwater Development above), St. Malo in 2003 and Jack in 2004. Operations in 2006 included a successful production test of the Jack No. 2 well and participation in the Kaskida discovery, which is our fourth Lower Tertiary discovery. We currently hold 273 blocks in the Lower Tertiary and have identified 19 additional prospects to date.

At St. Malo, in which our working interest is 22.5%, we plan to drill a second delineation well in late 2007 or early 2008. At Jack, where our working interest is 25%, we continue to evaluate with our partners our development options following the successful production test in 2006.

In addition to the 2006 Kaskida discovery, a subsequent sidetrack well at Kaskida was drilled in 2006 and another well operation is planned for 2007. Our working interest in Kaskida is 20%, and we believe Kaskida is the largest of our four Lower Tertiary discoveries to date. The Kaskida discovery was our first in the Keathley Canyon deepwater lease area. Twelve of the 19 additional Lower Tertiary exploratory prospects we have identified to date are on our Keathley Canyon acreage.

Also in 2006, we participated in a Miocene discovery on the Mission Deep prospect in which we have a 50% working interest. We have fifteen additional prospects in our deepwater Miocene inventory.

In total, we drilled three exploratory and delineation wells in the deepwater Gulf of Mexico in 2006, and plan to drill six such wells in 2007. Our working interests in these exploratory opportunities range from 20% to 100%.

Canada

Jackfish We are currently developing our 100%-owned Jackfish thermal heavy oil project in the non-conventional oil sands of east central Alberta. We will employ steam-assisted gravity drainage at Jackfish, and we expect to begin steam injection in the second quarter of 2007. Production is expected to eventually reach 35,000 barrels per day by the end of 2008 We drilled 19 pairs of producing and steam-injection wells in 2006, bringing the total number of well-pairs to 24. We hold approximately 80,000 net acres in the entire Jackfish area, which can support expansion of the original project. We requested regulatory approval in late September 2006 to increase the scope and size of the original project. We expect to decide in 2007 whether to proceed with this expansion, which could eventually add an additional 35,000 barrels per day of production.

Deep Basin Our properties in Canada s Deep Basin include portions of west central Alberta and east central British Columbia. We hold approximately 646,000 net acres in the Deep Basin. The area produces primarily natural gas and natural gas liquids from conventional reservoirs. Our average working interest in the

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Deep Basin is 46%. We drilled 115 gross wells in the Deep Basin in 2006 and plan to drill 57 gross wells in the area in 2007.

Lloydminster Our Lloydminster properties are located to the south and east of Jackfish in eastern Alberta and western Saskatchewan. Lloydminster produces heavy oil by conventional means without steam injection. We hold 2.1 million net acres and have a 97% average working interest in our Lloydminster properties. In 2006, we drilled 397 gross wells in the area and plan to drill 395 gross wells in 2007.

Peace River Arch The Peace River Arch is located in west central Alberta. We hold approximately 476,000 net acres in the area, which produces primarily natural gas and natural gas liquids from conventional reservoirs. Our average working interest in the area is about 69%. We drilled 82 gross wells in the Peace River Arch in 2006, and we expect to drill 62 additional wells here in 2007.

Northeast British Columbia Our Northeast British Columbia properties are located primarily in British Columbia and to a lesser extent in north western Alberta. We hold approximately 1.2 million net acres in the area. These properties produce principally natural gas from conventional reservoirs. We hold a 72% average working interest in these properties. We drilled 64 gross wells in the area in 2006, and we plan to drill 68 wells here in 2007.

International

Azerbaijan Outside North America, Devon s largest international property in terms of proved reserves is the Azeri-Chirag-Gunashli (ACG) oil field located offshore Azerbaijan in the Caspian Sea. Our production from ACG increased significantly in late 2006 following the payout of carried interest agreements with various partners in the field. Our production will increase again in 2007 as we benefit from a full year of the higher ownership interest after these payouts. We expect our share of ACG production in 2007 to total approximately 12 MMBoe. ACG produces crude oil from conventional reservoirs. We hold approximately 6,000 net acres in the ACG field and have a 5.6% working interest. In 2006, we participated in drilling 15 gross wells at ACG and expect to drill 13 gross wells in 2007.

China Our production in China is from the Panyu field in the Pearl River Mouth Basin in the South China Sea. Panyu produces oil from conventional reservoirs. In addition to Panyu, which is located on block 15/34, we also hold leases in two exploratory blocks offshore China. In total, we have 4.4 million net acres under lease in China. We have a 24.5% working interest at Panyu and 100% working interests in the exploratory blocks. We drilled six gross wells in China in 2006, all in the Panyu field. In 2007, we expect to drill seven gross wells in the Panyu field.

Brazil We expect to commence oil production in Brazil in 2007 from our Polvo field. Polvo, which we operate with a 60% interest, is located offshore in block BM-C-8. In addition to our development project at Polvo, we also hold acreage in nine exploratory blocks. In aggregate, we have 835,000 net acres in Brazil. Our working interests range from 18% to 100% in these blocks. We drilled three gross wells in Brazil in 2006 and plan to drill 11 gross wells in Brazil in 2007.

Equatorial Guinea All of our oil production from the West African country of Equatorial Guinea is from the offshore Zafiro field in the Gulf of Guinea. Zafiro is located on block B, and we also have interests in three additional exploratory blocks. We hold 518,000 net acres in the four blocks combined. Zafiro produces crude oil from conventional reservoirs. Our working interests (participating interests under the terms of the production sharing contracts) range from 24% to 38% in the four blocks. In 2006, we drilled 10 gross wells in Equatorial Guinea, all in the Zafiro field. In 2007, we plan to drill 10 gross wells in Equatorial Guinea. Equatorial Guinea is included in the West African assets we intend to sell during 2007.

Title to Properties

Title to properties is subject to contractual arrangements customary in the oil and gas industry, liens for current taxes not yet due and, in some instances, other encumbrances. We believe that such burdens do not materially detract from the value of such properties or from the respective interests therein or materially interfere with their use in the operation of the business.

As is customary in the industry, other than a preliminary review of local records, little investigation of record title is made at the time of acquisitions of undeveloped properties. Investigations, generally including a title opinion of outside counsel, are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties.

Item 3. *Legal Proceedings*

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. On February 1, 2006, the Court entered a scheduling order in which trial is set for November 2007. We believe we have acted reasonably, have legitimate and strong defenses to all allegations in the suit, and have paid royalties in good faith. We do not currently believe that we are subject to material exposure in association with this lawsuit and no related liability has been recorded in our consolidated financial statements.

Equatorial Guinea Investigation

The SEC has been conducting an inquiry into payments made to the government of Equatorial Guinea and to officials and persons affiliated with officials of the government of Equatorial Guinea. On August 9, 2005, we received a subpoena issued by the SEC pursuant to a formal order of investigation. We have cooperated fully with the SEC s requests for information in this inquiry. After responding in 2005 to such requests for information, we have not been contacted by the SEC. In the event that we receive any further inquiries, we will work with the SEC in connection with its investigation.

Other Matters

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

Item 4. *Submission of Matters to a Vote of Security Holders*

There were no matters submitted to a vote of security holders during the fourth quarter of 2006.

PART II

Item 5. *Market for Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Our common stock is traded on the New York Stock Exchange (the NYSE). On February 15, 2007, there were 16,228 holders of record of our common stock. The following table sets forth the quarterly high and low sales prices for our common stock as reported by the NYSE and dividends paid per share.

	Price Range of Common Stock		Dividends
	High	Low	per Share
2005:			
Quarter Ended March 31, 2005	$ 49.42	36.48	0.0750
Quarter Ended June 30, 2005	$ 52.31	40.60	0.0750
Quarter Ended September 30, 2005	$ 70.35	50.75	0.0750
Quarter Ended December 31, 2005	$ 69.79	54.01	0.0750
2006:			
Quarter Ended March 31, 2006	$ 69.97	55.31	0.1125
Quarter Ended June 30, 2006	$ 65.25	48.94	0.1125
Quarter Ended September 30, 2006	$ 74.65	57.19	0.1125
Quarter Ended December 31, 2006	$ 74.48	58.55	0.1125

We began paying regular quarterly cash dividends on our common stock in the second quarter of 1993. We anticipate continuing to pay regular quarterly dividends in the foreseeable future.

Issuer Purchases of Equity Securities

On August 3, 2005, we announced that our Board of Directors had authorized the repurchase of up to 50 million shares of our common stock. As of the end of the fourth quarter of 2006, 43.5 million shares remain available for purchase under this program. We suspended this stock repurchase program during the second quarter of 2006 in conjunction with our acquisition of Chief. In conjunction with the sales of our Egyptian and West African assets in 2007, we expect to resume this program in late 2007 by using a portion of the sale proceeds to repurchase common stock. Although this program expires at the end of 2007, it could be extended if necessary.

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Item 6. ***Selected Financial Data***

The following selected financial information (not covered by the report of independent registered public accounting firm) should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, and the consolidated financial statements and the notes thereto included in Item 8. Financial Statements and Supplementary Data.

	Year Ended December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
	(In millions, except per share data, ratios, prices and per Boe amounts)				
Operating Results					
Total revenues	$ 10,578	10,622	9,086	7,309	4,316
Total expenses and other income, net	6,566	6,117	5,810	5,020	4,450
Earnings (loss) from continuing operations before income taxes and cumulative effect of change in accounting principle	4,012	4,505	3,276	2,289	(134)
Total income tax expense (benefit)	1,189	1,606	1,095	527	(193)
Earnings from continuing operations before cumulative effect of change in accounting principle	2,823	2,899	2,181	1,762	59
Earnings (loss) from discontinued operations	23	31	5	(31)	45
Earnings before cumulative effect of change in accounting principle	2,846	2,930	2,186	1,731	104
Cumulative effect of change in accounting principle, net of tax				16	
Net earnings	$ 2,846	2,930	2,186	1,747	104
Net earnings applicable to common stockholders	$ 2,836	2,920	2,176	1,737	94
Basic net earnings per share:					
Earnings from continuing operations	$ 6.37	6.31	4.50	4.19	0.16
Earnings (loss) from discontinued operations	0.05	0.07	0.01	(0.07)	0.15
Cumulative effect of change in accounting principle				0.04	
Net earnings	$ 6.42	6.38	4.51	4.16	0.31
Diluted net earnings per share:					
Earnings from continuing operations	$ 6.29	6.19	4.37	4.07	0.16
Earnings (loss) from discontinued operations	$ 0.05	0.07	0.01	(0.07)	0.14
Cumulative effect of change in accounting principle				0.04	

Net earnings	$ 6.34	6.26	4.38	4.04	0.30

	Year Ended December 31, 2006	2005	2004	2003	2002
	(In millions, except per share data, ratios, prices and per Boe amounts)				
Cash dividends per common share	$ 0.45	0.30	0.20	0.10	0.10
Weighted average common shares outstanding Basic	442	458	482	417	309
Weighted average common shares outstanding Diluted	448	470	499	433	313
Ratio of earnings to fixed charges(1)	8.63	8.24	6.70	4.95	N/A
Ratio of earnings to combined fixed charges and preferred stock dividends(1)	8.38	8.04	6.53	4.82	N/A
Cash Flow Data					
Net cash provided by operating activities	$ 5,993	5,612	4,816	3,768	1,754
Net cash used in investing activities	$ (7,449)	(1,652)	(3,634)	(2,773)	(2,046)
Net cash provided by (used in) financing activities	$ 593	(3,543)	(1,001)	(414)	401
Production, Price and Other Data(2)					
Production:					
Oil (MMBbls)	55	62	74	60	42
Gas (Bcf)	815	827	891	863	761
NGLs (MMBbls)	23	24	24	22	19
MMBoe(3)	214	224	247	226	188
Average prices:					
Oil (Per Bbl)	$ 58.30	38.00	28.22	25.82	21.71
Gas (Per Mcf)	$ 6.06	6.99	5.32	4.51	2.80
NGLs (Per Bbl)	$ 32.10	28.96	23.04	18.65	14.05
Per Boe(3)	$ 41.51	39.48	29.92	25.93	17.61
Production and operating expenses per Boe(3)	$ 8.54	7.42	6.13	5.65	4.71
Depreciation, depletion and amortization of oil and gas properties per Boe(3)	$ 10.59	8.86	8.41	7.25	5.88

	December 31, 2006	2005	2004	2003	2002
	(In millions)				
Balance Sheet Data					
Total assets	$ 35,063	30,273	30,025	27,162	16,225
Long-term debt	$ 5,568	5,957	7,031	8,580	7,562
Stockholders equity	$ 17,442	14,862	13,674	11,056	4,653

(1) For purposes of calculating the ratio of earnings to fixed charges and the ratio of earnings to combined fixed charges and preferred stock dividends, (i) earnings consist of earnings from continuing operations before income taxes, plus fixed charges; (ii) fixed charges consist of interest expense, dividends on subsidiary s preferred stock, distributions on preferred securities of subsidiary trust, amortization of costs relating to indebtedness and the preferred securities of subsidiary trust, and one-third of rental expense estimated to be attributable to interest;

and (iii) preferred stock dividends consist of the amount of pre-tax earnings required to pay dividends on the outstanding preferred stock. For the year 2002, earnings were insufficient to cover fixed charges by $135 million, and were insufficient to cover combined fixed charges and preferred stock dividends by $151 million.

(2) The amounts presented under Production, Price and Other Data exclude the amounts related to discontinued operations in Egypt. The price data presented includes the effect of derivative financial instruments and fixed-price physical delivery contracts.

(3) Gas volumes are converted to Boe 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.

Item 7. *Management s Discussion and Analysis of Financial Condition and Results of Operations*

Introduction

The following discussion and analysis presents management s perspective of our business, financial condition and overall performance. This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future. Reference is made to Item 6. Selected Financial Data and Item 8. Financial Statements and Supplementary Data. Our discussion and analysis will relate to the following subjects:

Overview of Business

Overview of 2006 Results and Outlook

Results of Operations

Capital Resources, Uses and Liquidity

Contingencies and Legal Matters

Critical Accounting Policies and Estimates

Recently Issued Accounting Standards Not Yet Adopted

2007 Estimates

Overview of Business

Devon is one of the largest U.S. based independent oil and gas producers and processors of natural gas and natural gas liquids in North America. Our portfolio of oil and gas properties provides stable production and a platform for future growth. About 90 percent of our production is from North America. We also operate in selected international areas, including Azerbaijan, Brazil and China. Our production mix is about 65 percent natural gas and 35 percent oil and natural gas liquids such as propane, butane and ethane. We are currently producing about 2.3 billion cubic feet of natural gas each day, or about 3 percent of all the gas consumed in North America.

In managing our global operations, we have an operating strategy that is focused on creating and increasing value per share. Key elements of this strategy are replacing oil and gas reserves, growing production and exercising capital discipline. We must also control operating costs and manage commodity pricing risks to achieve long-term success. The discussion and analysis of our results of operations and other related information will refer to these factors.

Oil and gas reserve replacement Our financial condition and profitability are significantly affected by the amount of proved reserves we own. Oil and gas properties are our most significant asset, and the reserves that relate to such properties are key to our future success. To increase our proved reserves, we must replace reserves that have been produced with additional reserves from successful exploration and development activities or property acquisitions.

Production growth Our profitability and operating cash flows are largely dependent on the amount of oil, gas and NGLs we produce. Furthermore, growing production from existing properties is difficult because the rate of production from oil and gas properties generally declines as reserves are depleted.

As a result, we constantly drill for new proved reserves and develop proved undeveloped reserves on properties that provide a balance of near-term and long-term production. In addition, we may acquire properties with proved reserves that we can develop and subsequently produce to help us meet our production goals.

Capital investment discipline Effectively deploying our resources into capital projects is key to maintaining and growing future production and oil and gas reserves. Therefore, maintaining a disciplined approach to investing in capital projects is important to our profitability and financial condition. Also, our ability to control capital expenditures can be affected by changes in commodity prices. During times of high commodity prices, drilling and related costs often escalate due to the effects of supply versus demand economics. Approximately 82% of our planned 2007 investment in capital projects is dedicated to a foundation of low-risk projects primarily in North America. The remainder of our capital is invested in high-impact projects primarily in the Gulf of Mexico, Brazil and China. By deploying our capital in this manner, we are able to consistently deliver cost-efficient drill-bit growth and provide a strong source of cash flow while balancing short-term and long-term growth targets.

Operating cost controls To maintain our competitive position, we must control our lease operating costs and other production costs. As reservoirs are depleted and production rates decline, per unit production costs will generally increase and affect our profitability and operating cash flows. Similar to capital expenditures, our ability to control operating costs can be affected when commodity prices rise significantly. Our base North American production is focused in core areas of our operations where we can achieve economies of scale to assist our management of operating costs.

Commodity pricing risks Our profitability is highly dependent on the prices of oil, natural gas and NGLs. 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. To manage this volatility in the past, we have utilized financial hedging arrangements and fixed-price contracts on a portion of our production and may use such instruments in the future.

Overview of 2006 Results and Outlook

2006 was one of the best years in Devon s history. We achieved key operational successes and continued to execute our strategy to increase value per share. As a result, we delivered record amounts for earnings per share and operating cash flow and grew proved reserves to a new all-time high. Key measures of our financial and operating performance for 2006, as well as certain operational developments, are summarized below:

Net earnings declined 3% from $2.9 billion to $2.8 billion

Diluted net earnings per share increased 1% to $6.34 per diluted share

Net cash provided by operating activities reached $6.0 billion

Estimated proved reserves at December 31, 2006 reached a record amount of 2.4 billion Boe

Estimated proved reserves increased 533 million Boe through drilling, extensions, performance revisions and acquisitions

Capital expenditures for oil and gas exploration and development activities were $7.7 billion, including the $2.2 billion acquisition of Chief

Combined realized price for oil, gas and NGLs per Boe increased 5% to $41.51

Marketing and midstream margin remained flat at $448 million for 2006

We produced 214 million Boe in 2006, representing a 4% decrease compared to 2005. Excluding the effects of production lost due to the sale of non-core properties in the first half of 2005, our year-over-year production remained constant. Operating costs increased due to inflationary pressure driven by the effects of higher commodity prices and due to the weakened U.S. dollar compared to the Canadian dollar. Per unit lease operating expenses increased 17% to $6.95 per Boe.

During 2006, we utilized cash on hand, cash flow from operations, and $1.8 billion of commercial paper borrowings to fund our capital expenditures, repay $862 million in debt and repurchase $253 million of our common stock. We ended the year with $1.3 billion of cash and short-term investments.

From an operational perspective, our deepwater Gulf of Mexico exploration program has reached several important milestones related to the Lower Tertiary trend. To date, we have drilled four discovery wells in the Lower Tertiary Cascade in 2002, St. Malo in 2003, Jack in 2004 and Kaskida in the third quarter of 2006. Also in the third quarter of 2006, we announced the successful production test of the Jack No. 2 well in the Lower Tertiary. We currently hold 273 blocks in the Lower Tertiary and have identified 19 additional exploratory prospects within these blocks to date. These achievements support our positive view of the Lower Tertiary and demonstrate the growth potential of our high-impact exploration strategy on long-term production, reserves and value.

On June 29, 2006, we acquired Chief s oil and gas assets located in the Barnett Shale area of Texas for $2.2 billion. This transaction added 99.7 million Boe of proved reserves and 169,000 net acres to our Barnett Shale assets. This acquisition combined with our organic growth continues to extend our leadership position in the Barnett Shale and provides years of additional drilling inventory.

On November 14, 2006, we announced our plans to divest our operations in Egypt. At December 31, 2006, Egypt had proved reserves of eight million Boe. Subsequently, on January 23, 2007, we announced our plans to divest our operations in West Africa, including Equatorial Guinea, Cote d Ivoire, and other countries in the region. At December 31, 2006, our West Africa operations had proved reserves of 90 million Boe, or 4% of total proved reserves. We anticipate completing the sale of our Egyptian assets in the first half of 2007 and our West African assets in the third quarter of 2007. Divesting these properties will allow us to redeploy our financial and intellectual capital to the significant growth opportunities we have developed onshore in North America and in the deepwater Gulf of Mexico. Additionally, we will sharpen our focus in North America and concentrate our international operations in Brazil and China, where we have established competitive advantages.

Looking to 2007, we intend to use the proceeds from the sales of our operations in Egypt and West Africa to repay our outstanding commercial paper and resume common stock repurchases. In addition, our operational accomplishments to date have laid the foundation for continued growth in future years, at competitive unit costs, that we expect will continue to create additional value for our investors. In 2007, we expect to deliver reserve additions of 350 to 370 million Boe with related capital expenditures in the range of $5.3 to $5.7 billion. We expect production related to our continuing operations to increase approximately 10% from 2006 to 2007, which reflects the significant reserve additions in 2005 and 2006, and those expected in 2007.

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Results of Operations

Revenues

Changes in oil, gas and NGL production, prices and revenues from 2004 to 2006 are shown in the following tables. The amounts for all periods presented exclude our Egyptian operations. Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.

	Total Year Ended December 31,				
	2006	2006 vs 2005(2)	2005	2005 vs 2004(2)	2004
Production					
Oil (MMBbls)	55	−11%	62	−17%	74
Gas (Bcf)	815	−1%	827	−7%	891
NGLs (MMBbls)	23	−2%	24	−1%	24
Oil, gas and NGLs (MMBoe)(1)	214	−4%	224	−9%	247
Average Prices					
Oil (per Bbl)	$ 58.30	+53%	38.00	+35%	28.22
Gas (per Mcf)	$ 6.06	−13%	6.99	+32%	5.32
NGLs (per Bbl)	$ 32.10	+11%	28.96	+26%	23.04
Oil, gas and NGLs (per Boe)(1)	$ 41.51	+5%	39.48	+32%	29.92
Revenues ($ in millions)					
Oil	$ 3,205	+36%	2,359	+12%	2,099
Gas	4,932	−15%	5,784	+22%	4,732
NGLs	749	+9%	687	+24%	554
Oil, gas and NGLs	$ 8,886	+1%	8,830	+20%	7,385

	Domestic Year Ended December 31,				
	2006	2006 vs 2005(2)	2005	2005 vs 2004(2)	2004
Production					
Oil (MMBbls)	19	−23%	25	−19%	31
Gas (Bcf)	566	+2%	555	−8%	602
NGLs (MMBbls)	19	+3%	18	−4%	19
Oil, gas and NGLs (MMBoe)(1)	132	−3%	136	−10%	151
Average Prices					
Oil (per Bbl)	$ 62.23	+49%	41.64	+35%	30.84
Gas (per Mcf)	$ 6.09	−14%	7.08	+30%	5.43
NGLs (per Bbl)	$ 29.42	+10%	26.68	+24%	21.47
Oil, gas and NGLs (per Boe)(1)	$ 39.31	−2%	40.21	+31%	30.80

Revenues ($ in millions)					
Oil	$ 1,218	+15%	1,062	+9%	976
Gas	3,445	−12%	3,929	+20%	3,261
NGLs	548	+13%	484	+19%	405
Oil, gas and NGLs	$ 5,211	−5%	5,475	+18%	4,642

	Canada Year Ended December 31,				
	2006	2006 vs 2005(2)	2005	2005 vs 2004(2)	2004
Production					
Oil (MMBbls)	13	−2%	13	−5%	14
Gas (Bcf)	241	−8%	261	−6%	279
NGLs (MMBbls)	4	−11%	6	+8%	5
Oil, gas and NGLs (MMBoe)(1)	58	−7%	62	−5%	65
Average Prices					
Oil (per Bbl)	$ 46.94	+75%	26.88	+24%	21.60
Gas (per Mcf)	$ 6.05	−13%	6.95	+35%	5.15
NGLs (per Bbl)	$ 42.67	+15%	37.19	+27%	29.23
Oil, gas and NGLs (per Boe)(1)	$ 39.21	+3%	38.17	+33%	28.80
Revenues ($ in millions)					
Oil	$ 603	+71%	353	+18%	299
Gas	1,456	−20%	1,814	+26%	1,437
NGLs	201	+2%	196	+38%	143
Oil, gas and NGLs	$ 2,260	−4%	2,363	+26%	1,879

	International Year Ended December 31,				
	2006	2006 vs 2005(2)	2005	2005 vs 2004(2)	2004
Production					
Oil (MMBbls)	23	−4%	24	−19%	29
Gas (Bcf)	8	−25%	11	+6%	10
NGLs (MMBbls)		N/M		N/M	
Oil, gas and NGLs (MMBoe)(1)	24	−7%	26	−17%	31
Average Prices					
Oil (per Bbl)	$ 61.36	+52%	40.26	+41%	28.53
Gas (per Mcf)	$ 3.95	+5%	3.75	+13%	3.33
NGLs (per Bbl)	$	N/M	22.81	+8%	21.12
Oil, gas and NGLs (per Boe)(1)	$ 59.24	+53%	38.80	+39%	27.99
Revenues ($ in millions)					
Oil	$ 1,384	+47%	944	+15%	824
Gas	31	−21%	41	+20%	34
NGLs		N/M	7	+12%	6
Oil, gas and NGLs	$ 1,415	+43%	992	+15%	864

(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.

(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 our oil and gas price hedging activities. Following is a comparison of our average prices with and without the effect of hedges for each of the last three years.

	With Hedges			Without Hedges		
	2006	2005	2004	2006	2005	2004
Oil (per Bbl)	$ 58.30	38.00	28.22	58.30	48.43	36.02
Gas (per Mcf)	$ 6.06	6.99	5.32	6.01	7.04	5.34
NGLs (per Bbl)	$ 32.10	28.96	23.04	32.10	28.96	23.04
Oil, gas and NGLs (per Boe)	$ 41.51	39.48	29.92	41.34	42.55	32.37

The following table details the effects of changes in volumes and prices on our oil, gas and NGL revenues between 2004 and 2006.

	Oil	Gas	NGL	Total
	(In millions)			
2004 revenues	$ 2,099	4,732	554	7,385
Changes due to volumes	(347)	(337)	(8)	(692)
Changes due to prices	607	1,389	141	2,137
2005 revenues	2,359	5,784	687	8,830
Changes due to volumes	(270)	(86)	(11)	(367)
Changes due to prices	1,116	(766)	73	423
2006 revenues	$ 3,205	4,932	749	8,886

Oil Revenues

2006 vs. 2005 Oil revenues decreased $270 million due to a seven million barrel decrease in production. Production lost from properties divested in 2005 accounted for four million barrels of the decrease. A contractual reduction of our share of production from one of our international properties in mid-2005 also lowered 2006 volumes. These decreases were partially offset by a three million barrel increase in production resulting from reaching payout of certain carried interests in Azerbaijan.

Oil revenues increased $1.1 billion as a result of a 53% increase in our realized price. The expiration of oil hedges at the end of 2005 and a 17% increase in the average NYMEX West Texas Intermediate index price caused the increase in our realized oil price.

2005 vs. 2004 Oil revenues decreased $347 million due to a 12 million barrel decrease in production. Production lost from the 2005 property divestitures accounted for seven million barrels of the decrease. We also suspended certain domestic production in 2005 and 2004 due to the effects of Hurricanes Katrina, Rita, Dennis and Ivan. The volumes suspended in 2005 were one million barrels more than in 2004. The remainder of the decrease is due to certain international properties in which our ownership interest decreased after we recovered our costs under the applicable production sharing contracts.

Higher realized prices caused oil revenues to increase $607 million in 2005. Our 2005 oil prices rose primarily due to a 37% increase in the average NYMEX West Texas Intermediate index price.

Gas Revenues

2006 vs. 2005 A 12 Bcf decrease in production caused gas revenues to decrease by $86 million. Production lost from the 2005 property divestitures caused a decrease of 35 Bcf. As a result of the previously mentioned hurricanes, gas volumes suspended in 2006 were three Bcf more than those suspended in 2005. These decreases were partially offset by the June 2006 Chief acquisition, which contributed 10 Bcf of production during the last half of 2006, and additional production from new drilling and development in our U.S. onshore and offshore properties.

A 13% decline in average prices caused gas revenues to decrease $766 million in 2006.

2005 vs. 2004 A 64 Bcf decrease in production caused gas revenues to decrease by $337 million. Production associated with the 2005 property divestitures caused a decrease of 89 Bcf. We also suspended certain domestic gas production in 2005 and 2004 due to the previously mentioned hurricanes. The volumes suspended in 2005 were 12 Bcf more than in 2004. These decreases were partially offset by new drilling and development and increased performance in U.S. onshore and offshore properties.

A 32% increase in average gas prices contributed $1.4 billion of additional revenues in 2005.

Marketing and Midstream Revenues and Operating Costs and Expenses

The following table details the changes in our marketing and midstream revenues and operating costs and expenses between 2004 and 2006. The changes due to prices in the table represent the net effect on both revenues and expenses due to changes in the market prices for natural gas and NGLs.

	Revenues	Expenses
	(In millions)	
2004 marketing & midstream	$ 1,701	1,339
Changes due to volumes	(351)	(303)
Changes due to prices	442	306
2005 marketing & midstream	1,792	1,342
Changes due to volumes	159	117
Changes due to prices	(259)	(215)
2006 marketing & midstream	$ 1,692	1,244

2006 vs. 2005 Volume increases in our gas pipeline, gas sales and NGL marketing activities caused both revenues and expenses to increase in 2006. This additional activity was primarily due to our continued growth in the Barnett Shale and higher natural gas deliveries from third-party producers.

2005 vs. 2004 Volume decreases in 2005 caused both revenues and expenses to decline in 2005. The lower activity was primarily attributable to the sale of certain non-core assets in 2004 and 2005.

Oil, Gas and NGL Production and Operating Expenses

The details of the changes in oil, gas and NGL production and operating expenses between 2004 and 2006 are shown in the table below.

	Year Ended December 31,				
		2006 vs		2005 vs	
	2006	2005(1)	2005	2004(1)	2004

Production and operating expenses ($ in millions):					
Lease operating expenses	$ 1,488	+12%	1,324	+ 5%	1,259
Production taxes	341	+ 2%	335	+31%	255
Total production and operating expenses	$ 1,829	+10%	1,659	+10%	1,514
Production and operating expenses per Boe:					
Lease operating expenses	$ 6.95	+17%	5.92	+16%	5.10
Production taxes	1.59	+ 6%	1.50	+46%	1.03
Total production and operating expenses per Boe	$ 8.54	+15%	7.42	+21%	6.13

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

2006 vs. 2005 Lease operating expenses increased $164 million in 2006 largely due to higher commodity prices. Commodity price increases in 2005 and the first half of 2006 contributed to industry-wide inflationary pressures on materials and personnel costs. Additionally, consideration of higher commodity prices contributed to our decision to perform more well workovers and maintenance projects to maintain or improve production volumes. Commodity price increases also caused operating costs such as ad valorem taxes, power and fuel costs to rise.

A higher Canadian-to-U.S. dollar exchange rate in 2006 caused a $34 million increase in our costs. Lease operating expenses also increased $33 million due to the June 2006 Chief acquisition and the payouts of our carried interests in Azerbaijan in the last half of 2006. The increases in our lease operating expenses were partially offset by a decrease of $82 million related to properties that were sold in 2005.

The factors described above were also the primary factors causing lease operating expenses per Boe to increase during 2006. Although we divested properties in 2005 that had higher per-unit operating costs, the cost escalation largely related to higher commodity prices and the weaker U.S. dollar had a greater effect on our per unit costs than the property divestitures.

2005 vs. 2004 Lease operating expenses increased $65 million in 2005 largely due to higher commodity prices. As addressed above, commodity price increases led to overall industry inflation. Additionally, a higher Canadian-to-U.S. dollar exchange rate in 2005 caused a $30 million increase in 2005. Partially offsetting these increases was a decrease of $144 million in lease operating expenses related to properties that were sold in 2005.

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

The following table details the changes in production taxes between 2004 and 2006. The majority of our production taxes are assessed on our onshore domestic properties. In the U.S., most of the production taxes are based on a fixed percentage of revenues. Therefore, the changes due to revenues in the table primarily relate to changes in oil, gas and NGL revenues from our U.S. onshore properties.

		(In millions)
2004 production taxes	$	255
Change due to revenues		50
Change due to rate		30
2005 production taxes		335
Change due to revenues		(23)
Change due to rate		29
2006 production taxes	$	341

2006 vs. 2005 Production taxes increased $29 million due to an increase in the effective production tax rate in 2006. A new Chinese Special Petroleum Gain tax was the primary contributor to the higher rate.

2005 vs. 2004 Production taxes increased $30 million due to an increase in the effective production tax rate in 2005. An increase in Russian export tax rates was the primary contributor to the higher rate.

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

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

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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.

The following table details the changes in DD&A of oil and gas properties between 2004 and 2006. The changes due to volumes in the table represent the effect on DD&A due to decreases in combined oil, gas and NGL production.

	(In millions)
2004 DD&A	$ 2,077
Change due to volumes	(195)
Change due to rate	99
2005 DD&A	1,981
Change due to volumes	(85)
Change due to rate	370
2006 DD&A	$ 2,266

2006 vs. 2005 Oil and gas property related DD&A increased $370 million in 2006 due to an increase in the DD&A rate from $8.86 per Boe in 2005 to $10.59 per Boe in 2006. The largest contributor to the rate increase was inflationary pressure on both the costs incurred during 2006 as well as the estimated development costs to be spent in future periods on proved undeveloped reserves. Other factors contributing to the rate increase include the June 2006 Chief acquisition and the transfer of previously unproved costs to the depletable base as a result of 2006 drilling activities. A reduction in reserve estimates due to the effects of 2006 year-end commodity prices also contributed to the rate increase.

2005 vs. 2004 Oil and gas property related DD&A increased $99 million in 2005 due to an increase in the DD&A rate from $8.41 per Boe in 2004 to $8.86 per Boe in 2005. The largest contributor to the rate increase was the effect of inflationary pressure on finding and development costs for reserve discoveries and extensions. Changes in the Canadian-to-U.S. dollar exchange rate also caused the rate to increase. These increases were partially offset by a decrease in the rate as a result of our 2005 property divestitures.

General and Administrative Expenses (G&A)

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

Year Ended December 31,

	2006	2006 vs 2005	2005	2005 vs 2004	2004
			($ in millions)		
Gross G&A	$ 769	+33%	577	+6%	545
Capitalized G&A	(269)	+49%	(181)	+9%	(166)
Reimbursed G&A	(103)	−2%	(105)	+3%	(102)
Net G&A	$ 397	+36%	291	+5%	277

2006 vs. 2005 Gross G&A increased $192 million. Higher employee compensation and benefits costs caused gross G&A to increase $149 million. Of this increase, $34 million represented stock option expense recognized pursuant to our adoption in 2006 of Statement of Financial Accounting Standard No. 123(R), *Share-Based Payment.* An additional $28 million of the increase related to higher restricted stock compensation. In addition, changes in the Canadian-to-U.S. dollar exchange rate caused a $11 million increase in costs.

2005 vs. 2004 Gross G&A increased $32 million. Higher employee compensation and benefits costs caused gross G&A to increase $35 million. Of this increase, $17 million related to higher restricted stock compensation. In addition, changes in the Canadian-to-U.S. dollar exchange rate caused a $9 million increase in costs. These increases were partially offset by an $8 million decrease in rent expense resulting primarily from the abandonment of certain Canadian office space in 2004.

The factors discussed above were also the primary factors that caused the $88 million and $15 million increases in capitalized G&A in 2006 and 2005, respectively.

Interest Expense

The following schedule includes the components of interest expense between 2004 and 2006.

	Year Ended December 31,		
	2006	2005	2004
	(In millions)		
Interest based on debt outstanding	$ 486	507	513
Capitalized interest	(79)	(70)	(70)
Other interest	14	96	32
Total interest expense	$ 421	533	475

Interest based on debt outstanding decreased from 2004 to 2006 primarily due to the net effect of debt repayments during 2005 and 2006. This was partially offset by the effect of increased commercial paper borrowings during the last half of 2006 related to the acquisition of the Chief properties.

During 2005, we redeemed our $400 million 6.75% notes due March 15, 2011 and our zero coupon convertible senior debentures prior to their scheduled maturity dates. The other interest category in the table above includes $81 million in 2005 related to these early retirements.

During 2004, we repaid the balance under our $3 billion term loan credit facility prior to the scheduled repayment date. The other interest category in the table above includes $16 million in 2004 related to this early repayment.

Reduction of Carrying Value of Oil and Gas Properties

During 2006 and 2005, we reduced the carrying value of certain of our oil and gas properties due to full cost ceiling limitations and unsuccessful exploratory activities. A detailed description of how full cost ceiling limitations are determined is included in the Critical Accounting Policies and Estimates section of this report. A summary of these reductions and additional discussion is provided below.

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	Year Ended December 31, 2006 Gross	2006 Net of Taxes	2005 Gross	2005 Net of Taxes
	(In millions)			
Unsuccessful exploratory reductions:				
Nigeria	$ 85	85		
Brazil	16	16	42	42
Angola			170	119
Ceiling test reduction Russia	20	10		
Total	$ 121	111	212	161

2006 Reductions

We have committed to drill four wells in Nigeria. The first two wells were unsuccessful. After drilling the second unsuccessful well in the first quarter of 2006, we determined that the capitalized costs related to these two wells should be impaired. Therefore, in the first quarter of 2006, we recognized an $85 million impairment of our investment in Nigeria equal to the costs to drill the two dry holes and a proportionate share of block-related costs. There was no tax benefit related to this impairment.

During the second quarter of 2006, we drilled two unsuccessful exploratory wells in Brazil and determined that the capitalized costs related to these two wells should be impaired. Therefore, in the second quarter of 2006, we recognized a $16 million impairment of our investment in Brazil equal to the costs to drill the two dry holes and a proportionate share of block-related costs. There was no tax benefit related to this impairment. The two wells were unrelated to Devon s Polvo development project in Brazil.

As a result of a decline in projected future net cash flows, the carrying value of our Russian properties exceeded the full cost ceiling by $10 million at the end of the third quarter of 2006. Therefore, we recognized a $20 million reduction of the carrying value of our oil and gas properties in Russia, offset by a $10 million deferred income tax benefit.

2005 Reductions

Our interests in Angola were acquired through the 2003 Ocean Energy merger. Our Angolan drilling program discovered no proven reserves. After drilling three unsuccessful wells in the fourth quarter of 2005, we determined that all of the Angolan capitalized costs should be impaired.

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

Change in Fair Value of Derivative Financial Instruments

The details of the changes in fair value of derivative financial instruments between 2004 and 2006 are shown in the table below.

	2006	2005	2004
		(In millions)	
Option embedded in exchangeable debentures	$ 181	54	58
Non-qualifying commodity hedges		39	
Ineffectiveness of commodity hedges		5	5
Interest rate swaps	(3)	(4)	(1)
Total	$ 178	94	62

The change in the fair value of the embedded option relates to the debentures exchangeable into shares of Chevron Corporation common stock. These expenses were caused primarily by increases in the price of Chevron Corporation s common stock.

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

Other Income, Net

The following schedule includes the components of other income between 2004 and 2006.

	2006	2005	2004
		(In millions)	
Interest and dividend income	$ 100	95	45
Net gain on sales of non-oil and gas property and equipment	6	150	33
Loss on derivative financial instruments		(48)	
Gains from changes in foreign exchange rates		2	23
Other	9	(1)	25
Total	$ 115	198	126

Interest and dividend income increased from 2004 to 2005 primarily due to an increase in cash and short-term investment balances and higher interest rates.

During 2005, we sold certain non-core midstream assets for a net gain of $150 million. Also during 2005, we incurred a $55 million loss on certain commodity hedges that no longer qualified for hedge accounting and were settled prior to the end of their original term. These hedges related to U.S. and Canadian oil production from properties sold as part of our 2005 property divestiture program. This loss was partially offset by a $7 million gain related to interest rate swaps that were settled prior to the end of their original term in conjunction with the early redemption of the $400 million 6.75% senior notes in 2005.

The gains in 2005 and 2004 from changes in foreign exchange rates were primarily related to $400 million of Canadian subsidiary debt that was denominated in U.S. dollars. The debt was retired in 2005.

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Income Taxes

The following table presents our total income tax expense related to continuing operations and a reconciliation of our effective income tax rate to the U.S. statutory income tax rate for each of the past three years. The primary factors causing our effective rates to vary from 2004 to 2006, and differ from the U.S. statutory rate, are discussed below.

	2006	2005	2004
Total income tax expense (In millions)	$ 1,189	1,606	1,095
U.S. statutory income tax rate	35%	35%	35%
Canadian statutory rate reductions	(6)%		(1)%
Texas income-based tax	1%		
United States manufacturing deduction		(1)%	
Repatriation of Canadian earnings		1%	
Other		1%	(1)%
Effective income tax rate	30%	36%	33%

In 2006, 2005 and 2004, deferred income taxes were reduced $243 million, $14 million and $36 million, respectively, due to Canadian statutory rate reductions that were enacted in each such year.

In 2006, deferred income taxes increased $39 million due to the effect of a new income-based tax enacted by the state of Texas that replaces a previous franchise tax. The new tax is effective January 1, 2007.

In 2006 and 2005, income taxes were reduced $12 million and $25 million, respectively, due to a new U.S. tax deduction for companies with domestic production activities, including oil and gas extraction.

In 2005, we recognized $28 million of taxes related to our repatriation of $545 million to the U.S. The cash was repatriated due to tax legislation that allowed qualifying companies to repatriate cash from foreign operations at a reduced income tax rate. Substantially all of the cash repatriated by us in 2005 related to earnings of our Canadian subsidiary.

Results of Discontinued Operations

On November 14, 2006, we announced our plans to divest our operations in Egypt. We anticipate completing the sale of our Egyptian operations in the first half of 2007. Pursuant to accounting rules for discontinued operations, Egypt is considered a discontinued operation at the end of 2006. As a result, the Egypt financial results for 2006 and all prior periods have been reclassified and are presented as discontinued operations.

Following are the components of the results of discontinued operations between 2004 and 2006.

	2006	2005	2004
		(In millions)	

Earnings from discontinued operations before income taxes	$ 22	46	17
Income tax (benefit) expense	(1)	15	12
Earnings from discontinued operations	$ 23	31	5

Capital Resources, Uses and Liquidity

The following discussion of capital resources and liquidity should be read in conjunction with the consolidated financial statements included in Item 8. Financial Statements and Supplementary Data.

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Sources and Uses of Cash

The following table presents the sources and uses of our cash and cash equivalents from 2004 to 2006. The table presents capital expenditures on a cash basis. Therefore, these amounts differ from the amounts of capital expenditures, including accruals, that are referred to elsewhere in this document. Additional discussion of these items follows the table.

	2006	2005	2004
		(In millions)	
Sources of cash and cash equivalents:			
Operating cash flow continuing operations	$ 5,936	5,514	4,789
Sales of property and equipment	40	2,151	95
Net commercial paper borrowings	1,808		
Stock option exercises	73	124	268
Net decrease in short-term investments	106	287	
Other	36		
Total sources of cash and cash equivalents	7,999	8,076	5,152
Uses of cash and cash equivalents:			
Capital expenditures	(7,551)	(4,026)	(3,058)
Debt repayments	(862)	(1,258)	(973)
Repurchases of common stock	(253)	(2,263)	(189)
Dividends	(209)	(146)	(107)
Net increase in short-term investments			(626)
Total uses of cash and cash equivalents	(8,875)	(7,693)	(4,953)
Increase (decrease) from continuing operations	(876)	383	199
Increase (decrease) from discontinued operations	13	34	(18)
Effect of foreign exchange rates	13	37	39
Net increase (decrease) in cash and cash equivalents	$ (850)	454	220
Cash and cash equivalents at end of year	$ 756	1,606	1,152
Short-term investments at end of year	$ 574	680	967

Operating Cash Flow Continuing Operations

Net cash provided by operating activities (operating cash flow) is our primary source of capital and liquidity. Changes in operating cash flow are largely due to the same factors that affect our net earnings, with the exception of those earnings changes due to such noncash expenses as DD&A, property impairments, derivative fair value changes and deferred income tax expense. As a result, our operating cash flow increased in 2006 and 2005 compared to the previous years largely due to increases in net earnings, as discussed in the Results of Operations section of this report.

Sales of Property and Equipment

In 2005, we generated $2.2 billion in pre-tax proceeds from sales of property and equipment. These consisted of $2.0 billion related to the sale of non-core oil and gas properties and $0.2 billion related to the sale of non-core midstream assets. Net of related income taxes, these proceeds were $1.8 billion for oil and gas properties and $0.1 billion for midstream assets.

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Net Commercial Paper Borrowings

On June 29, 2006, we acquired Chief for $2 billion of cash and the assumption of $0.2 billion of liabilities. We funded a portion of the purchase price with $1.4 billion of borrowings issued under our commercial paper program. As a result of the Chief acquisition and success in other onshore U.S. locations, we accelerated certain oil and gas development activities into the last half of 2006. We borrowed an additional $0.4 billion of commercial paper to fund this accelerated development.

Capital Expenditures

The increases in operating cash flow have enabled us to invest larger amounts in capital projects. As a result, excluding the acquisition of the Chief properties, our capital expenditures increased 38% in 2006. The majority of this increase related to our expenditures for the acquisition, drilling or development of oil and gas properties, which totaled $5.0 billion in 2006, excluding the Chief acquisition. Inflationary pressure driven by higher commodity prices and increased drilling activities in the Barnett Shale, Gulf of Mexico, Carthage and Groesbeck areas of the U.S. contributed to the increase. In addition, the payouts of our carried interests in Azerbaijan in the last half of 2006 and the weaker U.S. dollar impact on our Canadian operations also contributed to the increase.

Capital expenditures in 2005 increased 32% compared to 2004 primarily due to an increase in our expenditures for the acquisition, drilling or development of oil and gas properties, which totaled $3.9 billion in 2005. Increased drilling activities in the Barnett Shale, the approximately $200 million acquisition of Iron River acreage in Canada and the $74 million purchase of the Serpentina FPSO in offshore Equatorial Guinea were large contributors to the increase. Inflationary pressure driven by higher commodity prices and the weaker U.S. dollar also caused our expenditures to increase from 2004 to 2005.

Debt Repayments

Our net debt retirements were $0.9 billion, $1.3 billion and $1.0 billion in 2006, 2005 and 2004, respectively. These amounts consisted of payments at the scheduled maturity dates with the exception of the following payments. The 2006 amount includes $0.2 billion related to the repayment of debt acquired in the Chief acquisition. The 2005 amount includes $0.8 billion related to the retirement of zero coupon convertible debentures due in 2020 and 6.75% notes due in 2011. The 2004 amount includes $635 million for the payment of the outstanding balance under a $3 billion term loan credit facility due in 2006.

Repurchases of Common Stock

In August 2005, we completed a share repurchase program that began in October 2004. Under this program, we repurchased 49.6 million shares of our common stock at a total cost of $2.3 billion, or $46.69 per share. In August 2005, we announced another program to repurchase up to an additional 50 million shares of our common stock. During 2005 and 2006, we repurchased 6.5 million shares for $387 million, or $59.80 per share, under this program.

Dividends

Our common stock dividends were $199 million, $136 million and $97 million in 2006, 2005 and 2004, respectively. We also paid $10 million of preferred stock dividends in 2006, 2005 and 2004. The 2006 and 2005 increases in common stock dividends were primarily related to a 50% increase in the dividend rate in the first quarter of both 2006 and 2005, partially offset by a decrease in outstanding shares due to share repurchases.

Changes in Short-Term Investments

To maximize our income on available cash balances, we invest in highly liquid, short-term investments. The purchase and sale of these short-term investments will cause cash and cash equivalents to decrease and

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increase, respectively. Short-term investment balances decreased $106 million and $287 million in 2006 and 2005, respectively, and increased $626 million in 2004.

Liquidity

Historically, our primary source of capital and liquidity has been operating cash flow. Additionally, we maintain a revolving line of credit and a commercial paper program which can be accessed as needed to supplement operating cash flow. Other available sources of capital and liquidity include the issuance of equity securities and long-term debt. During 2007, another major source of liquidity will be proceeds from the sales of our operations in Egypt and West Africa. We expect the combination of these sources of capital will be more than adequate to fund future capital expenditures, debt repayments, common stock repurchases, and other contractual commitments as discussed later in this section.

Operating Cash Flow

Our operating cash flow has increased nearly 25% since 2004, reaching a total of $5.9 billion in 2006. We expect operating cash flow to continue to be our primary source of liquidity. Our operating cash flow is sensitive to many variables, the most volatile of which is pricing of the oil, natural gas and NGLs produced. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict.

We periodically believe it appropriate to mitigate some of the risk inherent in oil and natural gas prices. We have used a variety of avenues to achieve this partial risk mitigation. We have utilized price collars to set minimum and maximum prices on a portion of our production. We have also utilized various 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. Based on contracts currently in place, approximately 5% of our estimated 2007 natural gas production (3% of our total Boe production) is subject to either price collars, swaps or fixed-price contracts.

Commodity prices can also affect our operating cash flow through an indirect effect on operating expenses. Significant commodity price increases, as experienced in recent years, can lead to an increase in drilling and development activities. As a result, the demand and cost for people, services, equipment and materials may also increase, causing a negative impact on our cash flow.

Credit Lines

Another source of liquidity is our $2.5 billion five-year, syndicated, unsecured revolving line of credit (the Senior Credit Facility). The Senior Credit Facility includes a five-year revolving Canadian subfacility in a maximum amount of U.S. $500 million. Amounts borrowed under the Senior Credit Facility may, at our election, bear interest at various fixed rate options for periods of up to twelve months. Such rates are generally less than the prime rate. However, we may elect to borrow at the prime rate. As of December 31, 2006, there were no borrowings under the Senior Credit Facility. The available capacity under the Senior Credit Facility as of December 31, 2006, net of $1.8 billion of outstanding commercial paper and $284 million of outstanding letters of credit, was approximately $408 million.

The Senior Credit Facility matures on April 7, 2011, and all amounts outstanding will be due and payable at that time unless the maturity is extended. Prior to each April 7 anniversary date, we have the option to extend the maturity of the Senior Credit Facility for one year, subject to the approval of the lenders. We are working to obtain lender approval to extend the current maturity date of April 7, 2011 to April 7, 2012. If successful, this maturity date extension will be effective April 7, 2007, provided we have not experienced a material adverse effect, as defined in the

Senior Credit Facility agreement, at that date.

The Senior Credit Facility contains only one material financial covenant. This covenant requires our ratio of total funded debt to total capitalization to be less than 65%. The credit agreement contains definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in our consolidated financial statements. As defined in the agreement, total funded debt excludes the debentures that are exchangeable into shares of Chevron Corporation common stock. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling impairments or goodwill impairments. As of December 31, 2006, our debt to capitalization ratio as calculated pursuant to this covenant was 27.3%.

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

We also have access to short-term credit under our commercial paper program. Total borrowings under the commercial paper program may not exceed $2 billion. Also, any borrowings under the commercial paper program reduce available capacity under the Senior Credit Facility on a dollar-for-dollar basis. Commercial paper debt generally has a maturity of between seven and 90 days, although it can have a maturity of up to 365 days, and bears 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, LIBOR, or the money market rate as found on the commercial paper market. As of December 31, 2006, we had $1.8 billion of commercial paper debt outstanding at an average rate of 5.37%.

Debt Ratings

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

There are no rating triggers in any of our contractual obligations that would accelerate scheduled maturities should our debt rating fall below a specified level. Our cost of borrowing under our Senior Credit Facility is predicated on our corporate debt rating. Therefore, even though a ratings downgrade would not accelerate scheduled maturities, it would adversely impact the interest rate on any borrowings under our Senior Credit Facility. Under the terms of the Senior Credit Facility, a one-notch downgrade would increase the fully-drawn borrowing costs for the Senior Credit Facility from LIBOR plus 45 basis points to a new rate of LIBOR plus 65 basis points. A ratings downgrade could also adversely impact our ability to economically access debt markets in the future. As of December 31, 2006, we were not aware of any potential ratings downgrades being contemplated by the rating agencies.

Capital Expenditures

In February 2007, we provided guidance for our 2007 capital expenditures which are expected to range from $5.7 billion to $6.2 billion. This represents the largest planned use of our 2007 operating cash flow, with the high end of the range being 11% higher than our 2006 capital expenditures, excluding the Chief acquisition. 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 2007 capital expenditures until later periods, or accelerate capital expenditures planned for periods beyond 2007 to achieve the desired balance between sources and uses of liquidity. Based upon current oil and natural gas price expectations for 2007, we anticipate having adequate capital resources to fund our 2007 capital expenditures.

Common Stock Repurchase Program

In August 2005, we announced a program to repurchase up to 50 million shares of our common stock. We had repurchased 6.5 million shares under this program through the middle of 2006 when the program was suspended as a result of the Chief acquisition. In conjunction with the sales of our Egyptian and West African operations, we expect to resume this repurchase program in late 2007 by using a portion of the sales proceeds to repurchase common stock. Although this program expires at the end of 2007, it could be extended if necessary.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2006, is provided in the following table.

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
			(In millions)		
Long-term debt(1)	$ 7,770	2,208	937	2,100	2,525
Interest expense(2)	5,797	492	764	690	3,851
Drilling and facility obligations(3)	2,993	886	1,137	844	126
Asset retirement obligations(4)	894	61	75	143	615
Firm transportation agreements(5)	574	123	173	106	172
Lease obligations(6)	595	80	163	123	229
Other	37	28	5	4	
Total	$ 18,660	3,878	3,254	4,010	7,518

(1) Long-term debt amounts represent scheduled maturities of our debt obligations at December 31, 2006, excluding $5 million of fair value adjustments and $8 million of net premiums included in the carrying value of debt. The Less than 1 Year amount includes $1.8 billion of short-term commercial paper borrowings. We intend to use the proceeds from the sales of our Egyptian and West African assets to repay our outstanding commercial paper. The 1-3 Years amount includes $760 million related to our debentures exchangeable into shares of Chevron Corporation common stock. As of December 31, 2006, we beneficially owned approximately 14.2 million shares of Chevron common stock for possible exchange for the exchangeable debentures. In addition, $284 million of letters of credit that have been issued by commercial banks on our behalf are excluded from the table. The majority of these letters of credit, if funded, would become borrowings under our revolving credit facility. Most of these letters of credit have been granted by financial institutions to support our international and Canadian drilling commitments.

(2) Interest expense amounts represent the scheduled fixed-rate and variable-rate cash payments related to our debt. Interest on our variable-rate debt was estimated based upon expected future interest rates as of December 31, 2006.

(3)

Drilling and facility obligations represent contractual agreements with third party service providers to procure drilling rigs and other related services for developmental and exploratory drilling and facilities construction. Included in the $3.0 billion total is $1.9 billion which relates to long-term contracts for three deepwater drilling rigs and certain other contracts for onshore drilling and facility obligations in which drilling or facilities construction has not commenced. The $1.9 billion represents the gross commitment under these contracts. Our ultimate payment for these commitments will be reduced by the amounts billed to our working interest partners. Payments for these commitments, net of amounts billed to partners, will be capitalized as a component of oil and gas properties.

(4) Asset retirement obligations represent estimated discounted costs for future dismantlement, abandonment and rehabilitation costs. These obligations are recorded as liabilities on our December 31, 2006 balance sheet.

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

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

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

We also lease two FPSO s that are being used in the Panyu project offshore China and the Polvo project offshore Brazil. The Panyu FPSO lease term expires in September 2009. The Polvo FPSO lease term expires in 2014.

Pension Funding and Estimates

Funded Status. As compared to the projected benefit obligation, our qualified and nonqualified defined benefit plans were underfunded by $178 million and $133 million at December 31, 2006 and 2005, respectively. A detailed reconciliation of the 2006 changes to our underfunded status is included in Note 6 to the accompanying consolidated financial statements. Of the $178 million underfunded status at the end of 2006, $156 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, 2006, these trusts had investments with a fair value of $59 million. The value of these trusts is included in noncurrent other assets in our accompanying consolidated balance sheets.

As compared to the accumulated benefit obligation, our qualified defined benefit plans were overfunded by $59 million at December 31, 2006. 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 2007, we anticipate the accumulated benefit obligation will remain fully funded without contributing to our defined benefit plans. Therefore, we don t expect to contribute to the plans during 2007.

Pension Estimate Assumptions. Our pension expense is recognized on an accrual basis over employees approximate service periods and is generally calculated independent of funding decisions or requirements. We recognized expense for our defined benefit pension plans of $31 million, $26 million and $26 million in 2006, 2005 and 2004, respectively. We estimate that our pension expense will approximate $43 million in 2007.

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

We assumed that our plan assets would generate a long-term weighted average rate of return of 8.40% at both December 31, 2006 and 2005. We developed these expected long-term rate of return assumptions by evaluating input from external consultants and economists as well as long-term inflation assumptions. The expected long-term rate of return on plan assets is based on a target allocation of investment types in such assets. The target investment allocation for our plan assets is 50% U.S. large cap equity securities; 15% U.S. small cap equity securities, equally allocated between growth and value; 15% international equity securities, equally allocated between growth and value; and 20% debt securities. We expect our long-term asset allocation on average to approximate the targeted allocation. We regularly review our actual asset allocation and periodically rebalance the investments to the targeted allocation when considered appropriate.

Pension expense increases as the expected rate of return on plan assets decreases. A decrease in our long-term rate of return assumption of 100 basis points (from 8.40% to 7.40%) would increase the expected 2007 pension expense by $6 million.

We discounted our future pension obligations using a weighted average rate of 5.72% at both December 31, 2006 and 2005. The discount rate is determined at the end of each year based on the rate at which obligations could be effectively settled. This rate is based on high-quality bond yields, after allowing for call and default risk. We consider high quality corporate bond yield indices, such as Moody s Aa, when selecting the discount rate.

The pension liability and future pension expense both increase as the discount rate is reduced. Lowering the discount rate by 25 basis points (from 5.72% to 5.47%) would increase our pension liability at December 31, 2006, by $25 million, and increase estimated 2007 pension expense by $3 million.

At December 31, 2006, we had actuarial losses of $214 million which will be recognized as a component of pension expense in future years. These losses are primarily due to reductions in the discount rate since 2001 and increases in participant wages. We estimate that approximately $15 million and $13 million of the unrecognized actuarial losses will be included in pension expense in 2007 and 2008, respectively. The $15 million estimated to be recognized in 2007 is a component of the total estimated 2007 pension expense of $43 million referred to earlier in this section.

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

On August 17, 2006, the Pension Protection Act was signed into law. Beginning in 2008, this act will cause extensive changes in the determination of both the minimum required contribution and the maximum tax deductible limit. Because the new required contribution will approximate our current policy of fully funding the accumulated benefit obligation, the changes are not expected to have a significant impact on future cash flows.

Beginning with our December 31, 2006 balance sheet, Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R),* requires us to recognize on our consolidated balance sheet the funded status of our defined benefit plans. The funded status is measured as the difference between the projected benefit obligation and the fair value of plan assets. As a result, we recognized as liabilities the actuarial losses and other costs that were previously unrecognized under prior accounting rules, and the net effect was also recorded as a reduction to stockholders equity on December 31, 2006. This reduction was $140 million, or less than 1% of our stockholders equity.

Contingencies and Legal Matters

For a detailed discussion of contingencies and legal matters, see Item 3. Legal Proceedings and Note 8 of the accompanying consolidated financial statements.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported

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amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from these estimates, and changes in these estimates are recorded when known.

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

Full Cost Ceiling Calculations

Policy Description

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

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

Judgments and Assumptions

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

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

While the quantities of proved reserves require substantial judgment, the associated prices of oil, natural gas and NGL reserves, and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that a 10% discount factor be used and that prices and costs in effect as of the last day of the period are held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs. Rather, they are based on such prices and costs in effect as of the end of each quarter when the ceiling calculation is performed. In calculating the ceiling, we adjust the end-of-period price by the effect of cash flow hedges in place. This adjustment requires little judgment as the end-of-period price is adjusted using the contract prices for our cash flow hedges. We had no such hedges outstanding at December 31, 2006.

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

Derivative Financial Instruments

Policy Description

The majority of our historical derivative instruments have consisted of commodity financial instruments used to manage our cash flow exposure to oil and gas price volatility. We have also entered into interest rate swaps to manage our exposure to interest rate volatility. The interest rate swaps mitigate either the cash flow effects of interest rate fluctuations on interest expense for variable-rate debt instruments, or the fair value effects of interest rate fluctuations on fixed-rate debt. We also have an embedded option derivative related to the fair value of our debentures exchangeable into shares of Chevron Corporation common stock.

All derivatives are recognized at their current fair value on our balance sheet. Changes in the fair value of derivative financial instruments are recorded in the statement of operations unless specific hedge accounting criteria are met. If such criteria are met for cash flow hedges, the effective portion of the change in the fair value is recorded directly to accumulated other comprehensive income, a component of stockholders equity, until the hedged transaction occurs. The ineffective portion of the change in fair value is recorded in the statement of operations. If hedge accounting criteria are met for fair value hedges, the change in the fair value is recorded in the statement of operations with an offsetting amount recorded for the change in fair value of the hedged item.

A derivative instrument qualifies for hedge accounting treatment if we designate the instrument as such on the date the derivative contract is entered into or the date of an acquisition or business combination which includes derivative contracts. Additionally, we must document the relationship between the hedging instrument and hedged item, as well as the risk-management objective and strategy for undertaking the instrument. We must also assess, both at the instrument s inception and on an ongoing basis, whether the derivative is highly effective in offsetting the change in cash flow of the hedged item.

Judgments and Assumptions

The estimates of the fair values of our commodity derivative instruments require substantial judgment. For these instruments, we obtain forward price and volatility data for all major oil and gas trading points in North America from independent third parties. These forward prices are compared to the price parameters contained in the hedge agreements. The resulting estimated future cash inflows or outflows over the lives of the hedge contracts are discounted using LIBOR and money market futures rates for the first year and money market futures and swap rates thereafter. In addition, we estimate the option value of price floors and price caps using an option pricing model.

These pricing and discounting variables are sensitive to the period of the contract and market volatility as well as changes in forward prices, regional price differentials and interest rates. Fair values of our other derivative instruments 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 instruments qualify for hedge accounting treatment. Changes in the fair values of derivatives that do not qualify for hedge accounting treatment can have a significant impact on our results of operations, but generally will not impact our liquidity or capital resources. Settlements of derivative instruments, regardless of whether they qualify for hedge accounting, do have an impact on our liquidity and results of operations. Generally, if actual market prices are higher than the price of the derivative instruments, 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 Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Business Combinations

Policy Description

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

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

Judgments and Assumptions

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

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

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

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

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

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

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

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

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

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

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

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

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

Valuation of Goodwill

Policy Description

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

Judgments and Assumptions

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

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

Recently Issued Accounting Standards Not Yet Adopted

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109.* Interpretation No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* This Interpretation is effective for fiscal years beginning after December 15, 2006, and we will adopt it in the first quarter of 2007. We do not expect the adoption of Interpretation No. 48 to have a material impact on our financial statements and related disclosures.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, *Fair Value Measurements.* Statement No. 157 provides a common definition of fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. However, this Statement does not require any new fair value measurements. Statement No. 157 is effective for fiscal years beginning after November 15, 2007. We are currently assessing the effect, if any, the adoption of Statement No. 157 will have on our financial statements and related disclosures.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R).* Statement No. 158 requires the recognition of the overfunded or underfunded status of a defined benefit postretirement plan in the balance sheet. We adopted this recognition requirement as of December 31, 2006. The effects of this adoption are summarized in Note 6 of the accompanying consolidated financial statements. Statement No. 158 also requires the measurement of plan assets and benefit obligations as of the date of the employer s fiscal year-end. The Statement provides two alternatives to transition to a fiscal year-end measurement date. This measurement requirement is effective for fiscal years ending after December 15, 2008. We have not yet adopted this measurement requirement, but we do not expect such adoption to have a material effect on our results of operations, financial condition, liquidity or compliance with debt covenants.

In February 2007, the FASB issued Statement of Financial Accounting Standards No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115.* Statement No. 159 permits entities to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which we elect the fair value measurement option would be reported in earnings. Statement No. 159 is effective for fiscal years beginning after November 15, 2007. However, early adoption is permitted for fiscal years beginning on or before November 15, 2007, provided we also elect to apply the provisions of Statement No. 157, *Fair Value Measurements*, at the same time. We are currently assessing the effect, if any, the adoption of Statement No. 159 will have on our financial statements and related disclosures.

2007 Estimates

The forward-looking statements provided in this discussion are based on our examination of historical operating trends, the information which was used to prepare the December 31, 2006 reserve reports and other data in our possession or available from third parties. These forward-looking statements were prepared assuming demand, curtailment, producibility and general market conditions for our oil, natural gas and NGLs during 2007 will be substantially similar to those of 2006, unless otherwise noted. We make reference to the Disclosure Regarding Forward-Looking Statements at the beginning of this report. Amounts related to Canadian operations have been converted to U.S. dollars using a projected average 2007 exchange rate of $0.89 U.S. dollar to $1.00 Canadian dollar.

On November 14, 2006, we announced our intent to divest our Egyptian oil and gas assets and terminate our operations in Egypt. We expect to complete this asset sale during the first half of 2007. Subsequently on January 23, 2007, we announced our intent to divest our West African oil and gas assets and terminate our operations in West Africa. We expect to complete this asset sale by the end of the third quarter in 2007. All Egyptian and West African related revenues, expenses and capital will be reported as discontinued operations in our 2007 financial statements. Accordingly, all forward-looking estimates in the following discussion exclude amounts related to our operations in Egypt and West Africa, unless otherwise noted. The assets held for sale represented less than five percent of our 2006 production and December 31, 2006 proved reserves.

Oil, Gas and NGL Production

Set forth in the following paragraphs are individual estimates of oil, gas and NGL production for 2007. We estimate, on a combined basis, that our 2007 oil, gas, and NGL production will total approximately 219 to 221 MMBoe. Of this total, approximately 92% is estimated to be produced from reserves classified as proved at December 31, 2006. The following estimates for oil, gas and NGL production are calculated at the midpoint of the estimated range for total production.

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Oil Production

Oil production in 2007 is expected to total approximately 55 MMBbls. Of this total, approximately 99% is estimated to be produced from reserves classified as proved at December 31, 2006. The expected production by area is as follows:

	(MMBbls)
U.S. Onshore	10
U.S. Offshore	9
Canada	15
International	21

Oil Prices

We have not fixed the price we will receive on any of our 2007 oil production. Our 2007 average prices for each of our areas are expected to differ from the NYMEX price as set forth in the following table. The NYMEX price is the monthly average of settled prices on each trading day for benchmark West Texas Intermediate crude oil delivered at Cushing, Oklahoma.

	Expected Range of Oil Prices as a % of NYMEX Price
U.S. Onshore	86% to 96%
U.S. Offshore	90% to 100%
Canada	60% to 70%
International	83% to 93%

Gas Production

Gas production in 2007 is expected to total approximately 841 Bcf. Of this total, approximately 88% is estimated to be produced from reserves classified as proved at December 31, 2006. The expected production by area is as follows:

	(Bcf)
U.S. Onshore	557
U.S. Offshore	75
Canada	207
International	2

Gas Prices

Our 2007 average prices for each of our areas are expected to differ from the NYMEX price as set forth in the following table. The NYMEX price is determined to be the first-of-month South Louisiana Henry Hub price index as published monthly in *Inside FERC.*

Based on contracts currently in place, we will have approximately 116 MMcf per day of gas production in 2007 that is subject to either fixed-price contracts, swaps, floors or collars. These amounts represent approximately 5% of our estimated gas production for 2007. Therefore, these various pricing arrangements are not expected to have a material impact on the ranges of estimated gas price realizations set forth in the following table.

	Expected Range of Gas Prices as a % of NYMEX Price
U.S. Onshore	80% to 90%
U.S. Offshore	96% to 106%
Canada	80% to 90%
International	100% to 110%

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NGL Production

We expect our 2007 production of NGLs to total approximately 25 MMBbls. Of this total, approximately 95% is estimated to be produced from reserves classified as proved at December 31, 2006. The expected production by area is as follows:

	(MMBbls)
U.S. Onshore	20
U.S. Offshore	1
Canada	4

Marketing and Midstream Revenues and Expenses

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

These factors, coupled with uncertainty of future natural gas and NGL prices, increase the uncertainty inherent in estimating future marketing and midstream revenues and expenses. Given these uncertainties, we estimate that marketing and midstream revenues will be between $1.70 billion and $2.10 billion, and marketing and midstream expenses will be between $1.31 billion and $1.67 billion.

Production and Operating Expenses

Our production and operating expenses include lease operating expenses, transportation costs and production taxes. These expenses vary in response to several factors. Among the most significant of these factors are additions to or deletions from the property base, changes in the general price level of services and materials that are used in the operation of the properties, the amount of repair and workover activity required and changes in production tax rates. Oil, natural gas and NGL prices also have an effect on lease operating expenses and impact the economic feasibility of planned workover projects. Given these uncertainties, we estimate that 2007 lease operating expenses (including transportation costs) will be between $1.70 billion and $1.77 billion. Additionally, we estimate our production taxes for 2007 to be between 3.6% and 4.1% of consolidated oil, natural gas and NGL revenues.

Depreciation, Depletion and Amortization (DD&A)

The 2007 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 2007 compared to the costs incurred for such efforts, and the revisions to our year-end 2006 reserve estimates that, based on prior experience, are likely to be made during 2007.

Given these uncertainties, we expect our oil and gas property related DD&A rate will be between $11.00 per Boe and $11.50 per Boe. Based on these DD&A rates and the production estimates set forth earlier, oil and gas property related DD&A expense for 2007 is expected to be between $2.42 billion and $2.53 billion.

Additionally, we expect our depreciation and amortization expense related to non-oil and gas property fixed assets to total between $210 million and $220 million.

Accretion of Asset Retirement Obligation

Accretion of asset retirement obligation in 2007 is expected to be between $45 million and $55 million.

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General and Administrative Expenses (G&A)

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

Given these limitations, G&A in 2007 is expected to be between $460 million and $480 million. This estimate includes approximately $60 million of noncash, share-based compensation, net of related capitalization in accordance with the full cost method of accounting for oil and gas properties.

Reduction of Carrying Value of Oil and Gas Properties

We follow the full cost method of accounting for our oil and gas properties described in Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates. Reductions to the carrying value of our oil and gas properties are largely dependent on the success of drilling results and oil and natural gas prices at the end of our quarterly reporting periods. Due to the uncertain nature of future drilling efforts and oil and natural gas prices, we are not able to predict whether we will incur such reductions in 2007.

Interest Expense

Future interest rates and debt outstanding have a significant effect on our interest expense. We can only marginally influence the prices we will receive in 2007 from sales of oil, natural gas and NGLs and the resulting cash flow. These factors increase the margin of error inherent in estimating future outstanding debt balances and related interest expense. Other factors which affect outstanding debt balances and related interest expense, such as the amount and timing of capital expenditures and proceeds from the sale of our assets in Egypt and West Africa, are generally within our control.

Based on the information related to interest expense set forth below, we expect our 2007 interest expense to be between $400 million and $410 million. This estimate assumes no material changes in prevailing interest rates. This estimate also assumes no material changes in our expected level of indebtedness, except for an assumption that our commercial paper will be repaid at the end of the second quarter of 2007.

The interest expense in 2007 related to our fixed-rate debt, including net accretion of related discounts, will be approximately $410 million. This fixed-rate debt removes the uncertainty of future interest rates from some, but not all, of our long-term debt.

Our floating rate debt is comprised of variable-rate commercial paper and one debt instrument which has been converted to floating rate debt through the use of an interest rate swap. Our floating rate debt is summarized in the following table:

Debt Instrument	**Notional Amount (In millions)**	**Floating Rate**
Commercial paper	$ 1,808(1)	Various(2)

4.375% senior notes due in Oct 2007	$ 400	LIBOR plus 40 basis points

(1) Represents outstanding balance as of December 31, 2006.

(2) The interest rate is based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market. As of December 31, 2006, the average rate on the outstanding balance was 5.37%.

Based on estimates of future LIBOR rates as of December 31, 2006, interest expense on floating rate debt, including net amortization of premiums, is expected to total between $80 million and $90 million in 2007.

Our interest expense totals include payments of facility and agency fees, amortization of debt issuance costs 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 2007 interest expense. Also, we expect to capitalize between $95 million and $105 million of interest during 2007.

Effects of Changes in Foreign Currency Rates

Foreign currency gains or losses are not expected to be material in 2007.

Other Income

We estimate that our other income in 2007 will be between $65 million and $85 million.

Historically, we maintained a comprehensive insurance program that included coverage for physical damage to our offshore facilities caused by hurricanes. Our historical insurance program also included substantial business interruption coverage which we are utilizing to recover costs associated with the suspended production related to hurricanes that struck the Gulf of Mexico in the third quarter of 2005.

Based on current estimates of physical damage and the anticipated length of time we will have production suspended, we expect our policy recoveries will exceed repair costs and deductible amounts. This expectation is based upon several variables, including the $467 million received in the third quarter of 2006 as a full settlement of the amount due from our primary insurers. As of December 31, 2006, $154 million of these proceeds had been utilized as reimbursement of past repair costs and deductible amounts. The remaining proceeds of $313 million will be utilized as reimbursement of our anticipated future repair costs. We have not yet received any settlements related to claims filed with our secondary insurers.

Should our total policy recoveries, including the partial settlements already received from our primary insurers, exceed all repair costs and deductible amounts, such excess will be recognized as other income in the statement of operations in the period in which such determination can be made. Based on the most recent estimates of our costs for repairs, we believe that some amount will ultimately be recorded as other income. However, the timing and amount that would be recorded as other income are uncertain. Therefore, the 2007 estimate for other income above does not include any amount related to hurricane proceeds.

Income Taxes

Our financial income tax rate in 2007 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2007 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 2007 income tax expense regardless of the level of pre-tax earnings that are produced.

Given the uncertainty of pre-tax earnings, we expect that our consolidated financial income tax rate in 2007 will be between 20% and 40%. The current income tax rate is expected to be between 15% and 25%. The deferred income tax rate is expected to be between 5% and 15%. Significant changes in estimated capital expenditures, production levels of oil, natural 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 2007 financial income tax rates.

Discontinued Operations

As previously discussed, we intend to divest our Egyptian and West African operations in 2007. We expect to complete the sale of Egypt during the first half of 2007 and the sale of West Africa during the third quarter of 2007. The following table shows the estimates for 2007 oil, gas and NGL production as well as the anticipated production and operating expenses associated with these discontinued operations for 2007. These estimates assume the sales of Egypt and West Africa will occur at the end of the second quarter of 2007. Pursuant to accounting rules for discontinued operations, the Egyptian assets will not be subject to DD&A during 2007 and the West African assets will only be subject to DD&A for the first month of 2007.

	Egypt	West Africa
Oil production (MMBbls)	1	5
Gas production (Bcf)		3
Total production (MMBoe)	1	6
Production and operating expenses (In millions)	$ 11	$ 34
Capital expenditures (In millions)	$ 17	$ 120

Year 2007 Potential Capital Resources, Uses and Liquidity

Capital Expenditures

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

Our capital expenditures budget is based on an expected range of future oil, natural gas and NGL prices as well as the expected costs of the capital additions. Should actual prices received differ materially from our price expectations for our future production, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2007 capital expenditures. In addition, if the actual material or labor costs of the budgeted items vary significantly from the anticipated amounts, actual capital expenditures could vary materially from our estimates.

Given the limitations discussed above, the following table shows expected drilling, development and facilities expenditures by geographic area. Production capital related to proved reserves relates to reserves classified as proved as of year-end 2006. Other production capital includes 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.

	U.S. Onshore	U.S. Offshore	Canada	International	Total
			(In millions)		
Production capital related to proved reserves	$ 1,170 - $1,270	$ 80 - $ 90	$ 410 - $ 450	$ 260 - $280	$ 1,920 - $2,090
Other production capital	$ 1,250 - $1,340	$ 220 - $230	$ 590 - $ 640	$ 15 - $ 20	$ 2,075 - $2,230
Exploration capital	$ 350 - $ 380	$ 290 - $310	$ 160 - $ 170	$ 75 - $ 85	$ 875 - $ 945
Total	$ 2,770 - $2,990	$ 590 - $630	$ 1,160 - $1,260	$ 350 - $385	$ 4,870 -$5,265

In addition to the above expenditures for drilling, development and facilities, we expect to spend between $330 million to $370 million on our marketing and midstream assets, which include our oil pipelines, gas processing plants, CO_2 removal facilities and gas transport pipelines. We also expect to capitalize between $245 million and $255 million of G&A expenses in accordance with the full cost method of accounting and to capitalize between $95 million and $105 million of interest. We also expect to pay between $40 million and $50 million for plugging and abandonment charges, and to spend between $135 million and $145 million for other non-oil and gas property fixed assets.

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Other Cash Uses

Our management expects the policy of paying a quarterly common stock dividend to continue. With the current $0.1125 per share quarterly dividend rate and 444 million shares of common stock outstanding as of December 31, 2006, dividends are expected to approximate $200 million. Also, we have $150 million of 6.49% cumulative preferred stock upon which we will pay $10 million of dividends in 2007.

Capital Resources and Liquidity

Our estimated 2007 cash uses, including our drilling and development activities, retirement of debt and repurchase of common stock, are expected to be funded primarily through a combination of operating cash flow and proceeds from the sale of our assets in Egypt and West Africa. Any remaining cash uses could be funded by increasing our borrowings under our commercial paper program or with borrowings from the available capacity under our credit facility, which was $408 million at December 31, 2006. The amount of operating cash flow to be generated during 2007 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 2007.

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

Item 7A. *Quantitative and Qualitative Disclosures about Market Risk*

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

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil, gas and NGL production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. and Canadian natural gas and NGL production. Pricing for oil, gas and NGL production has been volatile and unpredictable for several years. See Item 1A. Risk Factors.

Currently, we are largely accepting the volatility risk that oil, natural gas and NGL prices present. None of our future oil production is subject to price swaps or collars. With regard to our future natural gas production, based on contracts currently in place, we will have approximately 116 MMcf per day of gas production in 2007 that is subject to either fixed-price contracts, swaps, floors or collars. This amount represents approximately 5% of our estimated 2007 gas production (3% of our total Boe production). For the years 2008 through 2011, we have fixed-price physical delivery contracts covering Canadian natural gas production ranging from seven Bcf to 14 Bcf per year. These contracts are not expected to have a material effect on our realized gas prices from 2007 through 2011.

Interest Rate Risk

At December 31, 2006, we had debt outstanding of $7.8 billion. Of this amount, $5.6 billion, or 72%, bears interest at fixed rates averaging 7.3%. Additionally, we had $1.8 billion of outstanding commercial paper bearing interest at floating rates which averaged 5.37% at December 31, 2006. The remaining debt consists of $400 million 4.375% senior notes due in October of 2007. Through the use of an interest rate swap, this fixed-rate debt has been converted to floating-rate debt bearing interest equal to LIBOR plus 40 basis points.

We use a sensitivity analysis technique to evaluate the hypothetical effect that changes in interest rates may have on the fair value of any outstanding interest rate swap instruments. At December 31, 2006, a 10% increase in the underlying interest rates would have decreased the fair value of our interest rate swap by $2 million.

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

Foreign Currency Risk

Our net assets, net earnings and cash flows from our Canadian subsidiaries are based on the U.S. dollar equivalent of such amounts measured in the Canadian dollar functional currency. Assets and liabilities of the Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period. A 10% unfavorable change in the Canadian-to-U.S. dollar exchange rate would not materially impact our December 31, 2006 balance sheet.

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Item 8. ***Financial Statements and Supplementary Data***

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

All financial statement schedules are omitted as they are inapplicable or the required information has been included in the consolidated financial statements or notes thereto.

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, 2006 and 2005, and the related consolidated statements of operations, comprehensive income, stockholders equity and cash flows for each of the years in the three-year period ended December 31, 2006. 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, 2006 and 2005, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As described in Note 1 to the consolidated financial statements, as of January 1, 2006, the Company adopted Statements of Financial Accounting Standards No. 123(R), *Share-Based Payment*, and as of December 31, 2006 the Company adopted the balance sheet recognition provisions of Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R).*

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, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 26, 2007 expressed an unqualified opinion on management s assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Oklahoma City, Oklahoma
February 26, 2007

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 739	1,593
Short-term investments	574	680
Accounts receivable	1,393	1,565
Deferred income taxes	102	158
Current assets held for sale	81	66
Other current assets	323	144
Total current assets	3,212	4,206
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($3,674 and $2,704 excluded from amortization in 2006 and 2005, respectively)	41,889	33,824
Less accumulated depreciation, depletion and amortization	17,294	14,913
	24,595	18,911
Investment in Chevron Corporation common stock, at fair value	1,043	805
Goodwill	5,706	5,705
Assets held for sale	185	217
Other assets	322	429
Total assets	$ 35,063	30,273
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable trade	$ 1,190	928
Revenues and royalties due to others	529	666
Income taxes payable	197	293
Short-term debt	2,205	662
Accrued interest payable	114	127
Fair value of derivative financial instruments	6	18
Current portion of asset retirement obligation	61	50
Current liabilities associated with assets held for sale	5	19
Accrued expenses and other current liabilities	338	171
Total current liabilities	4,645	2,934
Debentures exchangeable into shares of Chevron Corporation common stock	727	709

Other long-term debt	4,841	5,248
Fair value of derivative financial instruments	302	125
Asset retirement obligation	833	610
Liabilities associated with assets held for sale	25	40
Other liabilities	598	371
Deferred income taxes	5,650	5,374
Stockholders equity:		
Preferred stock of $1.00 par value. Authorized 4,500,000 shares; issued 1,500,000 ($150 million aggregate liquidation value)	1	1
Common stock of $0.10 par value. Authorized 800,000,000 shares; issued 444,040,000 in 2006 and 443,488,000 in 2005	44	44
Additional paid-in capital	6,840	6,928
Retained earnings	9,114	6,477
Accumulated other comprehensive income	1,444	1,414
Treasury stock, at cost: 11,000 shares in 2006 and 37,000 shares in 2005	(1)	(2)
Total stockholders equity	17,442	14,862
Commitments and contingencies (Note 8)		
Total liabilities and stockholders equity	$ 35,063	30,273

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2006	2005	2004
	(In millions, except per share amounts)		
Revenues:			
Oil sales	$ 3,205	2,359	2,099
Gas sales	4,932	5,784	4,732
NGL sales	749	687	554
Marketing and midstream revenues	1,692	1,792	1,701
Total revenues	10,578	10,622	9,086
Expenses and other income, net:			
Lease operating expenses	1,488	1,324	1,259
Production taxes	341	335	255
Marketing and midstream operating costs and expenses	1,244	1,342	1,339
Depreciation, depletion and amortization of oil and gas properties	2,266	1,981	2,077
Depreciation and amortization of non-oil and gas properties	176	160	148
Accretion of asset retirement obligation	49	43	44
General and administrative expenses	397	291	277
Interest expense	421	533	475
Change in fair value of derivative financial instruments	178	94	62
Reduction of carrying value of oil and gas properties	121	212	
Other income, net	(115)	(198)	(126)
Total expenses and other income, net	6,566	6,117	5,810
Earnings from continuing operations before income tax expense	4,012	4,505	3,276
Income tax expense:			
Current	819	1,218	725
Deferred	370	388	370
Total income tax expense	1,189	1,606	1,095
Earnings from continuing operations	2,823	2,899	2,181
Discontinued operations:			
Earnings from discontinued operations before income taxes	22	46	17
Income tax (benefit) expense	(1)	15	12
Earnings from discontinued operations	23	31	5
Net earnings	2,846	2,930	2,186
Preferred stock dividends	10	10	10

Net earnings applicable to common stockholders	$ 2,836	2,920	2,176
Basic net earnings per share:			
Earnings from continuing operations	$ 6.37	6.31	4.50
Earnings from discontinued operations	0.05	0.07	0.01
Net earnings	$ 6.42	6.38	4.51
Diluted net earnings per share:			
Earnings from continuing operations	$ 6.29	6.19	4.37
Earnings from discontinued operations	0.05	0.07	0.01
Net earnings	$ 6.34	6.26	4.38
Weighted average common shares outstanding:			
Basic	442	458	482
Diluted	448	470	499

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2006	2005	2004
	(In millions)		
Net earnings	$ 2,846	2,930	2,186
Foreign currency translation:			
Change in cumulative translation adjustment	(25)	181	426
Income taxes	28	(19)	(38)
Total	3	162	388
Derivative financial instruments:			
Unrealized change in fair value		(255)	(848)
Reclassification adjustment for realized (gains) losses included in net earnings	(2)	685	635
Income taxes		(141)	62
Total	(2)	289	(151)
Pension and postretirement benefit plans:			
Change in additional minimum pension liability	30	(8)	61
Income taxes	(13)	3	(22)
Total	17	(5)	39
Investment in Chevron Corporation common stock:			
Unrealized holding gain	238	60	132
Income taxes	(86)	(22)	(47)
Total	152	38	85
Other comprehensive income, net of tax	170	484	361
Comprehensive income	$ 3,016	3,414	2,547

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Preferred Stock	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total Stockholders Equity
				(In millions)				
Balance as of December 31, 2003	$ 1	472	$ 47	9,011	1,614	569	(186)	11,056
Net earnings					2,186			2,186
Other comprehensive income						361		361
Stock option exercises		13	1	267			(21)	247
Restricted stock grants, net of cancellations		2						
Common stock repurchased		(5)					(190)	(190)
Common stock retired				(341)			341	
Conversion of subsidiary preferred stock		2					56	56
Common stock dividends					(97)			(97)
Preferred stock dividends					(10)			(10)
Share-based compensation				11				11
Excess tax benefits on share-based compensation				54				54
Balance as of December 31, 2004	1	484	48	9,002	3,693	930		13,674
Net earnings					2,930			2,930
Other comprehensive income						484		484
Stock option exercises		5		124				124
Restricted stock grants, net of cancellations		1						
Common stock repurchased		(47)					(2,275)	(2,275)
Common stock retired			(4)	(2,269)			2,273	
Common stock dividends					(136)			(136)
Preferred stock dividends					(10)			(10)
Share-based compensation				27				27
Excess tax benefits on share-based compensation				44				44
Balance as of December 31, 2005	1	443	44	6,928	6,477	1,414	(2)	14,862
Net earnings					2,846			2,846
Other comprehensive income						170		170
						(140)		(140)

Adoption of FASB Statement No. 158 (see Note 6)								
Stock option exercises		3		73				73
Restricted stock grants, net of cancellations		2		(3)				(3)
Common stock repurchased		(4)					(277)	(277)
Common stock retired				(278)			278	
Common stock dividends					(199)			(199)
Preferred stock dividends					(10)			(10)
Share-based compensation				84				84
Excess tax benefits on share-based compensation				36				36
Balance as of December 31, 2006	$ 1	444	$ 44	6,840	9,114	1,444	(1)	17,442

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2006	2005	2004
	(In millions)		
Cash flows from operating activities:			
Net earnings	$ 2,846	2,930	2,186
Less earnings from discontinued operations, net of tax	(23)	(31)	(5)
Adjustments to reconcile net earnings from continuing operations to net cash provided by operating activities:			
Depreciation, depletion and amortization	2,442	2,141	2,225
Deferred income tax expense	370	388	370
Net gain on sales of non-oil and gas property and equipment	(5)	(150)	(34)
Reduction of carrying value of oil and gas properties	121	212	
Other noncash charges	270	128	110
Changes in assets and liabilities:			
(Increase) decrease in:			
Accounts receivable	212	(279)	(318)
Other current assets	(37)	(17)	(18)
Long-term other assets	(66)	48	(93)
Increase (decrease) in:			
Accounts payable	(183)	255	189
Income taxes payable	(231)	69	208
Debt, including current maturities		(67)	16
Other current liabilities	78	(34)	(28)
Long-term other liabilities	142	(79)	(19)
Cash provided by operating activities continuing operations	5,936	5,514	4,789
Cash provided by operating activities discontinued operations	57	98	27
Net cash provided by operating activities	5,993	5,612	4,816
Cash flows from investing activities:			
Proceeds from sales of property and equipment	40	2,151	95
Capital expenditures	(7,551)	(4,026)	(3,058)
Purchases of short-term investments	(2,395)	(4,020)	(3,215)
Sales of short-term investments	2,501	4,307	2,589
Cash used in investing activities continuing operations	(7,405)	(1,588)	(3,589)
Cash used in investing activities discontinued operations	(44)	(64)	(45)
Net cash used in investing activities	(7,449)	(1,652)	(3,634)
Cash flows from financing activities:			
Net commercial paper borrowings, net of issuance costs	1,808		

Debt repayments, including current maturities		(862)	(1,258)	(973)
Proceeds from stock option exercises		73	124	268
Repurchases of common stock		(253)	(2,263)	(189)
Excess tax benefits related to share-based compensation		36		
Dividends paid on common stock		(199)	(136)	(97)
Dividends paid on preferred stock		(10)	(10)	(10)
Net cash provided by (used in) financing activities		593	(3,543)	(1,001)
Effect of exchange rate changes on cash		13	37	39
Net (decrease) increase in cash and cash equivalents		(850)	454	220
Cash and cash equivalents at beginning of year (including cash related to assets held for sale)		1,606	1,152	932
Cash and cash equivalents at end of year (including cash related to assets held for sale)	$	756	1,606	1,152
Supplementary cash flow data:				
Interest paid	$	464	663	474
Income taxes paid	$	960	1,092	477

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

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 in the United States are concentrated in the following geographic areas:

- the Mid-Continent area of the central and southern United States, principally in north and east Texas and Oklahoma;

- 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 offshore areas of the Gulf of Mexico; and

- the onshore areas of the Gulf Coast, principally in south Texas and south Louisiana.

Devon s Canadian activities are located primarily in the Western Canadian Sedimentary Basin. Devon s international activities outside of North America are located primarily in Azerbaijan, Brazil, China and various countries in West Africa. On January 23, 2007, Devon announced its plans to divest its West African operations. See Note 13.

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 controlled subsidiaries are included in the accompanying consolidated financial statements. All significant intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates in the Preparation of Financial Statements

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

Property and Equipment

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and major development projects of oil and gas properties are also capitalized. 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.

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 estimated after-tax 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. In calculating future net revenues, prices and costs used are those as of the end of the appropriate quarterly period. These prices are not changed except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including designated cash flow hedges in place. Devon had no such hedges outstanding at December 31, 2006 or December 31, 2005.

Any excess of the net book value, less related deferred taxes, over the ceiling 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.

Capitalized costs are depleted by an equivalent unit-of-production method, converting gas to oil at the ratio of six thousand cubic feet of natural gas to one barrel of oil. Depletion is calculated using the capitalized costs, including estimated asset retirement costs, plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, net of estimated salvage values.

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.

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.

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 ranging from three to 39 years.

Devon recognizes liabilities for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms, and natural gas processing plants when there is a legal obligation associated with the retirement of such assets and the amount can be reasonably estimated. The initial measurement of an asset retirement obligation is recorded as a liability at its fair value, with an offsetting asset retirement cost recorded as an increase to the associated property and equipment on the consolidated balance sheet. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost. The asset retirement cost is depreciated using a systematic and rational method similar to that used for the associated property and equipment.

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, 2006 and 2005, Devon s short-term investments consisted of $574 million and $680 million, respectively, of auction rate

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

securities classified as available for sale. Although Devon s auction rate securities have contractual maturities of more than 10 years, the underlying interest rates on such securities reset at intervals ranging from seven to 90 days. Therefore, these auction rate securities are priced and subsequently trade as short-term investments because of the interest rate reset feature. As a result, Devon has classified its auction rate securities as short-term investments in the accompanying consolidated balance sheet.

Devon s only other significant investment security is its investment in approximately 14.2 million shares of Chevron Corporation common stock which is reported at fair value. Except for unrealized losses that are determined to be other than temporary , the tax effected unrealized gain or loss on the investment in Chevron Corporation common stock is recognized in other comprehensive income 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 2006, 2005 and 2004. 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, 2006 and 2005:

	December 31,	
	2006	2005
	(In millions)	
United States	$ 3,053	3,056
Canada	2,585	2,581
International	68	68
Total	$ 5,706	5,705

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, delivery has occurred, title has transferred and 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. Taxes assessed by governmental authorities on oil, gas and NGL revenues are presented separately from such revenues as production taxes in the statement of operations.

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, delivery or performance has occurred, title has transferred and collectibility of the revenue is probable. Revenues and expenses attributable to Devon s gas and NGL purchase and processing contracts are reported on a gross basis since Devon takes title to the products and has risks and rewards of ownership. The gas purchased under these contracts is processed in Devon-owned plants.

Major Purchasers

During 2006, revenues received from ExxonMobil and its affiliates were $1.1 billion, or 10% of Devon s consolidated revenues. No purchaser accounted for over 10% of Devon s revenues in 2005 or 2004.

Derivative Instruments

The majority of Devon s derivative instruments consist of commodity financial instruments used to manage Devon s cash flow 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 cash flow effects of interest rate fluctuations on interest expense for variable-rate debt instruments, or the fair value effects of interest rate fluctuations on fixed-rate debt. Devon also has an embedded option derivative related to the fair value of its debentures exchangeable into shares of Chevron Corporation common stock.

All derivatives are recognized at their current fair value as fair value of derivative financial instruments on the balance sheet. Changes in the fair value of derivative financial instruments are recorded in the statement of operations unless specific hedge accounting criteria are met. If such criteria are met for cash flow hedges, the effective portion of the change in the fair value is recorded directly to accumulated other comprehensive income, a component of stockholders equity, until the hedged transaction occurs. The ineffective portion of the change in fair value is recorded in the statement of operations. If such criteria are met for fair value hedges, the change in the fair value is recorded in the statement of operations with an offsetting amount recorded for the change in fair value of the hedged item.

A derivative instrument qualifies for hedge accounting treatment if Devon designates the instrument as such on the date the derivative contract is entered into or the date of an acquisition or business combination which includes derivative contracts. Additionally, Devon must document the relationship between the hedging instrument and hedged item, as well as the risk-management objective and strategy for undertaking the instrument. Devon must also assess, both at the instrument s inception and on an ongoing basis, whether the derivative is highly effective in offsetting the change in cash flow of the hedged item.

During 2006, Devon entered into and acquired certain commodity derivative instruments. For such instruments, Devon chose not to meet the necessary criteria to qualify these derivative instruments for hedge accounting treatment. Therefore, Devon recorded a $37 million gain in gas sales in the statement of operations for the change in fair value related to these instruments.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents the components of the 2006, 2005 and 2004 change in fair value of derivative financial instruments presented in the accompanying statement of operations. Significant items are discussed in more detail following the table.

	2006	2005	2004
		(In millions)	
Option embedded in exchangeable debentures	$ 181	54	58
Non-qualifying commodity hedges		39	
Ineffectiveness of commodity hedges		5	5
Interest rate swaps	(3)	(4)	(1)
Total change in fair value of derivative financial instruments	$ 178	94	62

The change in the fair value of the embedded option relates to the debentures exchangeable into shares of Chevron Corporation common stock. These expenses were caused primarily by increases in the price of Chevron Corporation s common stock.

During 2005 and 2004, Devon had a number of commodity derivative instruments that qualified for hedge accounting treatment as described above. During 2005, certain of these derivatives ceased to qualify for hedge accounting treatment. In the third quarter of 2005, certain oil derivatives ceased to qualify for hedge accounting primarily as a result of deferred production caused by hurricanes in the Gulf of Mexico. Because these contracts no longer qualified for hedge accounting, Devon recognized $39 million in losses as change in fair value of derivative financial instruments in the accompanying 2005 statement of operations.

In addition to the changes in fair value of non-qualifying commodity hedges presented in the table above, Devon also recognized in 2005 a $55 million loss related to certain oil hedges that no longer qualified for hedge accounting due to the effect of the 2005 property divestiture program. These commodity instruments related to 5,000 barrels per day of U.S. oil production and 3,000 barrels per day of Canadian oil production from properties that were sold as part of Devon s divestiture program. This loss is presented in other income in the accompanying 2005 statement of operations. During 2004, no derivatives ceased to qualify for hedge accounting.

In addition to the changes in fair value of Devon s interest rate swaps presented in the table above, settlements on these interest rate swaps increased interest expense by $15 million and $12 million in 2006 and 2005, respectively, and decreased interest expense $18 million in 2004.

The following table presents the balances of Devon s accumulated net gain (loss) on cash flow hedges included in accumulated other comprehensive income.

(In millions)

December 31, 2003	$	(135)
December 31, 2004	$	(286)
December 31, 2005	$	3
December 31, 2006	$	1

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Market risk is the change in the value of a derivative instrument that results from a change in commodity prices, interest rates or other relevant underlyings. 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.

Stock Options

Effective January 1, 2006, Devon adopted Statement of Financial Accounting Standard No. 123(R), *Share-Based Payment*, (SFAS No. 123(R)), using the modified prospective transition method. SFAS No. 123(R) requires equity-classified, 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. Under the modified prospective transition method, share-based awards granted or modified on or after January 1, 2006, are recognized in compensation expense over the applicable vesting period. Also, any previously granted awards that were not fully vested as of January 1, 2006 are recognized as compensation expense over the remaining vesting period. No retroactive or cumulative effect adjustments were required upon Devon s adoption of SFAS No. 123(R).

Prior to adopting SFAS No. 123(R), Devon accounted for its fixed-plan employee stock options using the intrinsic-value based method prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees,* (APB No. 25) and related interpretations. This method required compensation expense to be recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price.

Had the fair value provisions of SFAS No. 123(R) been applied in 2005 and 2004, Devon s net earnings and net earnings per share would have differed from the amounts actually reported as shown in the following table.

	Year Ended December 31, 2005	Year Ended December 31, 2004
	(In millions, except per share amounts)	
Net earnings available to common stockholders, as reported	$ 2,920	2,176
Add share-based employee compensation expense included in reported net earnings, net of related tax expense	18	7
Deduct total share-based employee compensation expense determined under fair value based method for all awards (see Note 9), net of related tax expense	(44)	(31)
Net earnings available to common stockholders, pro forma	$ 2,894	2,152
Net earnings per share available to common stockholders:		
As reported:		

Basic	$	6.38	4.51
Diluted	$	6.26	4.38
Pro forma:			
Basic	$	6.32	4.46
Diluted	$	6.21	4.33

As a result of adopting SFAS No. 123(R), Devon s 2006 earnings from continuing operations before income tax expense was $26 million lower than if Devon had continued to account for share-based

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

compensation under APB No. 25. Additionally, 2006 earnings from continuing operations and net earnings were both $17 million lower. The related 2006 basic and diluted earnings per share amounts were both approximately $0.04 per share lower. Prior to the adoption of SFAS No. 123(R), Devon presented all tax benefits of deductions resulting from the exercise of stock options as operating cash inflows in the statement of cash flows. SFAS No. 123(R) requires the cash inflows resulting from tax deductions in excess of the compensation expense recognized for those stock options (excess tax benefits) to be classified as financing cash inflows. As required by SFAS No. 123(R), Devon recognized $36 million of excess tax benefits as financing cash inflows for 2006. In 2005 and 2004, excess tax benefits of $44 million and $54 million, respectively, were classified as operating cash inflows.

Income Taxes

Devon accounts for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases, as well as the future tax consequences attributable to the future utilization of existing tax net operating loss and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. At December 31, 2006, 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, 2006. If it becomes apparent that some or all of the undistributed earnings will be distributed, Devon would then record taxes on those earnings.

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, as calculated using the treasury stock method, reflects the potential dilution that could occur if Devon s dilutive outstanding stock options were exercised. For 2005 and 2004, the calculation of diluted shares also assumed that Devon s previously outstanding zero coupon convertible senior debentures were converted to common stock.

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The following table reconciles earnings from continuing operations and common shares outstanding used in the calculations of basic and diluted earnings per share for 2006, 2005 and 2004.

	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, 2006:			
Earnings from continuing operations	$ 2,823		
Less preferred stock dividends	(10)		
Basic earnings per share	2,813	442	$ 6.37
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		6	
Diluted earnings per share	$ 2,813	448	$ 6.29
Year Ended December 31, 2005:			
Earnings from continuing operations	$ 2,899		
Less preferred stock dividends	(10)		
Basic earnings per share	2,889	458	$ 6.31
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 (increase in net earnings is net of income tax expense of $14 million)(1)	24	4	
Diluted earnings per share	$ 2,913	470	$ 6.19
Year Ended December 31, 2004:			
Earnings from continuing operations	$ 2,181		
Less preferred stock dividends	(10)		
Basic earnings per share	2,171	482	$ 4.50
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 (increase in net earnings is net of income tax expense of $6 million)		10	9		
Diluted earnings per share	$	2,181	499	$	4.37

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

Certain options to purchase shares of Devon s common stock were excluded from the dilution calculations because the options were antidilutive. These excluded options totaled 3 million, 0.2 million and 4 million in 2006, 2005 and 2004, respectively.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Foreign Currency Translation Adjustments

The U.S. dollar is the functional currency for Devon s consolidated operations except its Canadian subsidiaries which use the Canadian dollar as the 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. Canadian 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. The following table presents the balances of Devon s cumulative translation adjustments included in accumulated other comprehensive income.

	(In millions)
December 31, 2003	$ 666
December 31, 2004	$ 1,054
December 31, 2005	$ 1,216
December 31, 2006	$ 1,219

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 8 for a discussion of amounts recorded for these liabilities.

Recently Issued Accounting Standards Not Yet Adopted

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109.* Interpretation No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* This Interpretation is effective for fiscal years beginning after December 15, 2006, and Devon will adopt it in the first quarter of 2007. Devon does not expect the adoption of Interpretation No. 48 to have a material impact on its financial statements and related disclosures.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, *Fair Value Measurements.* Statement No. 157 provides a common definition of fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. However, this Statement does not require any new fair value measurements. Statement No. 157 is effective for fiscal years beginning after November 15, 2007. Devon is currently assessing the effect, if any, the adoption of Statement No. 157 will have on its financial statements and related disclosures.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R).* Statement No. 158 requires the recognition of the overfunded or underfunded status of a defined benefit postretirement plan in the balance sheet. Devon adopted this recognition requirement as of December 31, 2006. The effects of this adoption are summarized in Note 6. Statement

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

No. 158 also requires the measurement of plan assets and benefit obligations as of the date of the employer s fiscal year-end. The Statement provides two alternatives to transition to a fiscal year-end measurement date. This measurement requirement is effective for fiscal years ending after December 15, 2008. Devon has not yet adopted this measurement requirement, but Devon does not expect such adoption to have a material effect on its results of operations, financial condition, liquidity or compliance with debt covenants.

In February 2007, the FASB issued Statement of Financial Accounting Standards No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115.* Statement No. 159 permits entities to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which Devon elects the fair value measurement option would be reported in earnings. Statement No. 159 is effective for fiscal years beginning after November 15, 2007. However, early adoption is permitted for fiscal years beginning on or before November 15, 2007, provided Devon also elects to apply the provisions of Statement No. 157, *Fair Value Measurements*, at the same time. Devon is currently assessing the effect, if any, the adoption of Statement No. 159 will have on its financial statements and related disclosures.

2. Accounts Receivable

The components of accounts receivable include the following:

	December 31, 2006	December 31, 2005
	(In millions)	
Oil, gas and NGL revenue	$ 1,020	1,113
Joint interest billings	209	206
Marketing and midstream revenue	138	173
Other	31	78
	1,398	1,570
Allowance for doubtful accounts	(5)	(5)
Net accounts receivable	$ 1,393	1,565

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Property and Equipment and Asset Retirement Obligations

Property and equipment included the following:

	December 31, 2006	December 31, 2005
	(In millions)	
Oil and gas properties:		
Subject to amortization	$ 35,798	29,257
Not subject to amortization	3,674	2,704
Accumulated depreciation, depletion and amortization	(16,610)	(14,398)
Net oil and gas properties	22,862	17,563
Other property and equipment	2,417	1,863
Accumulated depreciation and amortization	(684)	(515)
Net other property and equipment	1,733	1,348
Property and equipment, net of accumulated depreciation, depletion and amortization	$ 24,595	18,911

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

The following is a summary of Devon s oil and gas properties not subject to amortization as of December 31, 2006:

	Costs Incurred in 2006	2005	2004	Prior to 2004	Total
	(In millions)				
Acquisition costs	$ 1,357	296	119	691	2,463
Exploration costs	423	239	86	62	810
Development costs	130	19		39	188
Capitalized interest	70	56	52	35	213
Total oil and gas properties not subject to amortization	$ 1,980	610	257	827	3,674

At December 31, 2006, Devon s investment in countries where proved reserves have not been established was $61 million, consisting of $56 million in Nigeria and $5 million in Ghana.

Chief Acquisition

On June 29, 2006, Devon acquired the oil and gas assets of privately-owned Chief Holdings LLC (Chief). Devon paid $2.0 billion in cash and assumed approximately $0.2 billion of net liabilities in the transaction for a total purchase price of $2.2 billion. Devon funded the acquisition price, and the immediate retirement of $180 million of assumed debt, with $718 million of cash on hand and approximately $1.4 billion of borrowings issued under its commercial paper program. The acquired oil and gas properties consist of 99.7 MMBoe (unaudited) of proved reserves and leasehold totaling 169,000 net acres located in the Barnett

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Shale area of north Texas. Devon allocated approximately $1.0 billion of the purchase price to proved reserves and approximately $1.2 billion to unproved properties.

Property Divestitures

During 2005, Devon divested certain non-core oil and gas properties in the offshore Gulf of Mexico and onshore in the United States and Canada. From these sales, Devon received $2.0 billion of gross proceeds. After-tax, the proceeds were approximately $1.8 billion. Certain information regarding these sales is included in the following table.

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

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

On November 14, 2006, Devon announced that it intends to divest its operations in Egypt. Also, on January 23, 2007, Devon announced that it intends to divest its operations in West Africa. See Note 13 for more discussion regarding these planned divestitures.

Asset Retirement Obligations

Following is a reconciliation of the asset retirement obligation for the years ended December 31, 2006 and 2005.

	Year Ended December 31, 2006	2005
	(In millions)	
Asset retirement obligation as of beginning of year	$ 660	731
Liabilities incurred	102	44
Liabilities settled	(62)	(42)
Liabilities assumed by others		(199)
Revision of estimated obligation	149	76

Accretion expense on discounted obligation	49	43
Foreign currency translation adjustment	(4)	7
Asset retirement obligation as of end of year	894	660
Less current portion	61	50
Asset retirement obligation, long-term	$ 833	610

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Debt and Related Expenses

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

	December 31, 2006	2005
	(In millions)	
Commercial paper	$ 1,808	
Debentures exchangeable into shares of Chevron Corporation common stock:		
4.90% due August 15, 2008	444	444
4.95% due August 15, 2008	316	316
Discount on exchangeable debentures	(33)	(51)
Other debentures and notes:		
2.75% due August 1, 2006		500
6.55% due August 2, 2006 ($200 million Canadian)		172
4.375% due October 1, 2007	400	400
10.125% due November 15, 2009	177	177
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
Fair value adjustment on debt related to interest rate swaps	(5)	(18)
Net premium on other debentures and notes	41	51
	7,773	6,619
Less amount classified as short-term debt	2,205	662
Long-term debt	$ 5,568	5,957

Maturities of short-term and long-term debt as of December 31, 2006, excluding premiums, discounts and the $5 million fair value adjustment, are as follows (in millions):

2007	$ 2,208
2008	760
2009	177
2010	
2011	2,100

2012 and thereafter	2,525
Total	$ 7,770

Credit Facilities with Banks

Devon has a $2.5 billion five-year, syndicated, unsecured revolving line of credit (the Senior Credit Facility). The Senior Credit Facility includes a five-year revolving Canadian subfacility in a maximum amount of U.S. $500 million.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Senior Credit Facility matures on April 7, 2011, and all amounts outstanding will be due and payable at that time unless the maturity is extended. Prior to each April 7 anniversary date, Devon has the option to extend the maturity of the Senior Credit Facility for one year, subject to the approval of the lenders. Devon is working to obtain lender approval to extend the current maturity date of April 7, 2011 to April 7, 2012. If successful, this maturity date extension will be effective on April 7, 2007, 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 $2.3 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. 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 Chevron Corporation common stock. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling property impairments or goodwill impairments. At December 31, 2006, Devon was in compliance with such covenants and restrictions. Devon s debt-to-capitalization ratio at December 31, 2006, as calculated pursuant to the terms of the agreement, was 27.3%.

As of December 31, 2006, there were no borrowings under the Senior Credit Facility. The available capacity under the Senior Credit Facility as of December 31, 2006, net of $284 million of outstanding letters of credit and $1.8 billion of outstanding commercial paper, was approximately $408 million.

Commercial Paper

Devon also has a commercial paper program under which it may borrow up to $2 billion. 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, and bears 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, LIBOR, or the money market rate as found on the commercial paper market. As of December 31, 2006, Devon had $1.8 billion of commercial paper debt outstanding at an average rate of 5.37%. The $1.8 billion of commercial paper is classified as short-term debt in the accompanying consolidated balance sheet.

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, 2006, the call price was 101% of principal. The exchangeable debentures are exchangeable at the option of the holders at any time prior to maturity, unless previously redeemed, for shares of Chevron common stock. In lieu of delivering Chevron common stock to an exchanging debenture holder, Devon may, at its option, pay to such holder an amount of cash equal to the market value of the Chevron common stock. At maturity, holders who have not exercised their exchange rights will receive an amount in cash equal to the principal amount of the debentures.

As of December 31, 2006, Devon beneficially owned approximately 14.2 million shares of Chevron common stock. These shares have been deposited with an exchange agent for possible exchange for the

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

exchangeable debentures. Each $1,000 principal amount of the exchangeable debentures is exchangeable into 18.6566 shares of Chevron common stock, an exchange rate equivalent to $53.60 per share of Chevron stock.

The exchangeable debentures were assumed as part of the 1999 PennzEnergy acquisition. As a result, 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 was allocated between the interest-bearing debt and the option to exchange Chevron common stock that is embedded in the debentures. Accordingly, a discount was recorded on the debentures and is being accreted using the effective interest method which raised the effective interest rate on the debentures to 7.76%.

Other Debentures and Notes

Following are descriptions of the various other debentures and notes outstanding at December 31, 2006, as listed in the table presented at the beginning of this note.

Ocean Debt

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

Debt Assumed	Fair Value of Debt Assumed (In millions)		Effective Rate of Debt Assumed
4.375% due October 2007 (principal of $400 million)	$	410	3.8%
7.250% due October 2011 (principal of $350 million)	$	406	4.9%
8.250% due July 2018 (principal of $125 million)	$	147	5.5%
7.500% due September 2027 (principal of $150 million)	$	169	6.5%

The $400 million 4.375% senior notes due in October of 2007 are subject to a fixed-to-floating interest rate swap. Through the use of this swap, this fixed-rate debt has been converted to floating-rate debt bearing interest equal to LIBOR plus 40 basis points.

10.125% Debentures due November 15, 2009

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

6.875% Notes due September 30, 2011 and 7.875% Debentures due September 30, 2031

On October 3, 2001, Devon, through Devon Financing Corporation, U.L.C. (Devon Financing), sold these notes and debentures which are unsecured and unsubordinated obligations of Devon Financing. Devon has fully and unconditionally guaranteed on an unsecured and unsubordinated basis the obligations of Devon Financing under the debt securities. The proceeds from the issuance of these debt securities were used to fund a portion of the Anderson acquisition.

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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 used to retire other indebtedness.

Interest Expense

The following schedule includes the components of interest expense between 2004 and 2006.

	Year Ended December 31, 2006	2005	2004
	(In millions)		
Interest based on debt outstanding	$ 486	507	513
Capitalized interest	(79)	(70)	(70)
Other interest	14	96	32
Total interest expense	$ 421	533	475

Interest based on debt outstanding decreased from 2004 to 2006 primarily due to the net effect of debt repayments during 2005 and 2006 partially offset by the effect of commercial paper borrowings during the last half of 2006.

During 2005, Devon redeemed its $400 million 6.75% notes due March 15, 2011 and its zero coupon convertible senior debentures prior to their scheduled maturity dates. The other interest category in the table above includes $81 million in 2005 related to these early retirements.

During 2004, Devon repaid the balance under its $3 billion term loan credit facility prior to the scheduled repayment date. The other interest category in the table above includes $16 million in 2004 related to this early repayment.

5. Financial Instruments

The following table presents the carrying amounts and estimated fair values of Devon s financial instrument assets (liabilities) at December 31, 2006 and 2005.

	2006		2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Investment in Chevron Corporation common stock	$ 1,043	1,043	805	805

Oil and gas price hedge agreements	$	39	39		
Interest rate swap agreements	$	(6)	(6)	(22)	(22)
Embedded option in exchangeable debentures	$	(302)	(302)	(121)	(121)
Debt	$	(7,773)	(8,725)	(6,619)	(7,642)

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, 2006 and 2005.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Embedded option in exchangeable debentures The fair value of the embedded option is based on a quote obtained from a broker.

Debt The fair values of fixed-rate 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 floating-rate debt are estimated to approximate the carrying amounts because the interest rates paid on such debt are generally set for periods of three months or less.

6. Retirement Plans

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

Devon has a funding policy regarding the Qualified Plans such that it will contribute the amount of funds necessary so that the Qualified Plans assets will be approximately equal to the related accumulated benefit obligation. As of December 31, 2006 and 2005, the fair value of the Qualified Plans assets were $590 million and $533 million, respectively, which was $59 million and $37 million more, respectively, than the related accumulated benefit obligation. The actual amount of contributions required during future periods will depend on investment returns from the plan assets during the same period as well as changes in long-term interest rates.

The Supplemental Plans provide retirement benefits for certain employees whose benefits under the Qualified Plans are limited by income tax regulations. The Supplemental Plans benefits are based on the employee s years of service and compensation. For certain Supplemental Plans, Devon has established trusts to fund these plans benefit obligations. The total value of these trusts was $59 million at both December 31, 2006 and 2005, and is included in non-current other assets in the consolidated balance sheets. For the remaining Supplemental Plans for which trusts have not been established, benefits are funded from Devon s available cash and cash equivalents.

Devon also has defined benefit postretirement plans (Postretirement Plans) which provide benefits for substantially all U.S. 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.

Devon uses a November 30 measurement date to value its pension and other postretirement benefits obligations. As described in Note 1, Devon will be required to use a December 31 measurement date beginning with the fiscal year ending December 31, 2008. Devon does not expect the change in its measurement date from November 30 to December 31 will have a material effect on the net periodic benefit cost or benefit obligation.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Benefit Obligations and Plan Assets

Beginning with Devon s December 31, 2006 balance sheet, Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R),* requires Devon to recognize on its consolidated balance sheet the funded status of its defined benefit plans. The funded status is measured as the difference between the projected benefit obligation and the fair value of plan assets. The following table presents the incremental effect on Devon s December 31, 2006 balance sheet as a result of adopting this recognition requirement from Statement No. 158.

	Before Adjustment	Adoption Adjustment (In millions)	After Adjustment
Other noncurrent assets	$ 448	(126)	322
Total assets	$ 35,189	(126)	35,063
Other current liabilities	$ 326	12	338
Other noncurrent liabilities	$ 517	81	598
Deferred income taxes	$ 5,729	(79)	5,650
Accumulated other comprehensive income	$ 1,584	(140)	1,444
Total stockholders equity	$ 17,582	(140)	17,442
Total liabilities and stockholders equity	$ 35,189	(126)	35,063

The following table presents the status of Devon s pension and other postretirement benefit plans for 2006 and 2005. 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, 2006 and 2005 was $652 million and $607 million, respectively.

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
	(In millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 666	588	54	50
Service cost	23	18	1	1
Interest cost	39	35	3	3
Participant contributions			2	2
Amendments	2		1	

Foreign exchange rate changes	1	1		
Actuarial loss	66	50		6
Benefits paid	(29)	(26)	(9)	(8)
Benefit obligation at end of year	768	666	52	54

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
	(In millions)			
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 533	456		
Actual return on plan assets	79	37		
Employer contributions	6	65	6	6
Participant contributions			2	2
Benefits paid	(29)	(26)	(8)	(8)
Foreign exchange rate changes	1	1		
Fair value of plan assets at end of year	590	533		
Funded status at end of year	(178)	(133)	(52)	(54)
Unrecognized net actuarial loss		195		7
Unrecognized prior service cost (benefit)		6		(8)
Net amount recognized in balance sheet	$ (178)	68	(52)	(55)
Amounts recognized in balance sheet:				
Noncurrent assets	$ 2			
Current liabilities	(7)		(5)	
Noncurrent liabilities	(173)		(47)	
Prepaid cost		144		
Accrued benefit cost		(109)		(55)
Intangible asset		3		
Additional minimum pension liability		30		
Net amount	$ (178)	68	(52)	(55)
Amounts recognized in accumulated other comprehensive income:				
Net actuarial loss	$ 214		6	
Prior service cost (benefit)	6		(7)	
Total	$ 220		(1)	

The plan assets for pension benefits in the table above exclude the assets held in trusts for the Supplemental Plans. However, employer contributions for pension benefits in the table above include $6 million and $5 million in 2006 and 2005, respectively, which were transferred from the trusts established for the Supplemental Plans.

Certain of Devon s pension and postretirement plans have a projected benefit obligation in excess of plan assets at December 31, 2006 and 2005. The aggregate benefit obligation and fair value of plan assets for these plans is included below.

	December 31, 2006	December 31, 2005
	(In millions)	
Projected benefit obligation	$ 755	707
Fair value of plan assets	$ 574	518

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Certain of Devon s pension plans have an accumulated benefit obligation in excess of plan assets at December 31, 2006 and 2005. The aggregate accumulated benefit obligation and fair value of plan assets for these plans is included below.

	December 31, 2006	2005
	(In millions)	
Accumulated benefit obligation	$ 121	111
Fair value of plan assets		

The plan assets included in the above two tables exclude the Supplemental Plan trusts which had a total value of $59 million at both December 31, 2006 and 2005.

Net Periodic Benefit Cost and Other Comprehensive Income

The following table presents the components of net periodic benefit cost and other comprehensive income for Devon s pension and other postretirement benefit plans for 2006, 2005 and 2004.

	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	2006	2005	2004
	(In millions)					
Net periodic benefit cost:						
Service cost	$ 23	18	15	1	1	1
Interest cost	39	35	32	3	3	4
Expected return on plan assets	(44)	(36)	(30)			
Termination benefits			1			
Amortization of prior service cost	1	1	1		(1)	(1)
Recognition of net actuarial loss	12	8	7	1		
Net periodic benefit cost	$ 31	26	26	5	3	4
Other comprehensive income:						
Change in additional minimum pension liability	$ 30	(8)	61			

The following table presents the estimated net actuarial loss and prior service cost for the pension and other postretirement plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost during 2007.

	Pension Benefits	Other Postretirement Benefits
	(In millions)	
Net actuarial loss	$ 15	1
Prior service cost	1	
Total	$ 16	1

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Assumptions

The following table presents the weighted average actuarial assumptions that were used to determine benefit obligations and net periodic benefit costs for 2006, 2005 and 2004.

	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	2006	2005	2004
	(In millions)					
Assumptions to determine benefit obligations:						
Discount rate	5.72%	5.72%	5.74%	5.50%	5.75%	5.75%
Rate of compensation increase	7.00%	4.50%	4.50%	N/A	N/A	N/A
Assumptions to determine net periodic benefit cost:						
Discount rate	5.72%	5.98%	6.23%	5.75%	6.00%	6.25%
Expected return on plan assets	8.40%	8.40%	8.34%	N/A	N/A	N/A
Rate of compensation increase	4.50%	4.50%	4.88%	N/A	N/A	N/A

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

Rate of compensation increase For measurement of the 2006 benefit obligation for the pension plans, the 7% compensation increase in the table above represents the assumed increase for 2007 and 2008. The rate was assumed to decrease one percent annually to 5% in the year 2010 and remain at that level thereafter. For measurement of the 2005 and 2004 benefit obligations for the pension plans, the compensation increases in the table above represent the assumed increases for all future years.

Expected return on plan assets 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, 2006, the target investment allocation for Devon s plan assets was 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 expected rate of return on plan assets was determined by evaluating input from external consultants and economists as well as long-term inflation assumptions. Devon expects the long-term asset allocation to approximate the targeted allocation. Therefore, the expected long-term rate of return on plan assets is based on the target allocation of investment types in such assets.

The following table presents the weighted-average asset allocation for Devon s pension plans at December 31, 2006 and 2005, and the target allocation for 2007 by asset category:

	2007	**2006**	**2005**
Asset category:			
Equity securities	80%	83%	83%
Debt securities	20%	17%	16%
Other	%	%	1%
Total	100%	100%	100%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other assumptions For measurement of the benefit obligation for the other postretirement medical plans, a 10% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2007. The rate was assumed to decrease one percent annually to 5% in the year 2012 and remain at that level thereafter. Assumed health care cost-trend rates affect the amounts reported for retiree health care costs. A one-percentage-point change in the assumed health care cost-trend rates would have the following effects on the December 31, 2006 other postretirement benefits obligation and the 2006 service and interest cost components of net periodic benefit cost.

	One Percent Increase	One Percent Decrease
	(In millions)	
Effect on benefit obligation	$ 1	(1)
Effect on service and interest costs	$	

Expected Cash Flows

The following table presents expected cash flow information for Devon s pension and other postretirement benefit plans.

	Pension Benefits	Other Postretirement Benefits
	(In millions)	
Devon contributions 2007	$ 7	5
Benefit payments:		
2007	$ 30	5
2008	$ 31	5
2009	$ 33	5
2010	$ 35	5
2011	$ 37	5
2012 - 2016	$ 245	21

Expected 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 2007, $7 million of pension benefits is expected to be funded from the trusts established for the Supplemental Plans and all $5 million of other postretirement benefits 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 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 $15 million, $12 million and $11 million for the years ended December 31, 2006, 2005 and 2004, 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 2006, 2005 and 2004, Devon s combined

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

contributions to the Canadian defined contribution plan and the Canadian savings plan were $12 million, $10 million and $9 million, respectively.

7. Stockholders Equity

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

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

Devon s Board of Directors has designated a certain number of shares of the preferred stock as Series A Junior Participating Preferred Stock (the Series A Junior Preferred Stock) in connection with the adoption of the shareholder rights plan described later in this note. On April 25, 2003, the Board increased the designated shares from 2.0 million to 2.9 million. At December 31, 2006, 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.

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.

Stock Repurchases

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

On August 3, 2005, Devon announced another program to repurchase up to 50 million shares of its common. During 2005, Devon repurchased 2.2 million shares at a cost of $134 million, or $60.16 per share, under this program. During 2006, Devon repurchased 4.3 million shares at a cost of $253 million, or $59.61 per share, under this program. As of February 1, 2007, Devon has repurchased 6.5 million shares under this program for $387 million, or $59.80 per share.

This program was suspended in 2006 as a result of the Chief acquisition (see Note 3). In conjunction with the sales of Egypt and West Africa (see Note 13), Devon expects to resume this repurchase program in late 2007 by using a portion of the sale proceeds to repurchase common stock. Although this program expires at the end of 2007, it could be extended if necessary.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Shareholder Rights Plan

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

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

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

Dividends

Dividends on Devon s common stock were paid in 2006, 2005 and 2004 at a per share rate of $0.1125, $0.075 and $0.05 per quarter, respectively.

8. 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, 2006, Devon s consolidated balance sheet included $5 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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 November 2007. 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.

In 1995, the United States Congress passed the Deep Water Royalty Relief Act. The intent of this legislation was to encourage deep water exploration in the Gulf of Mexico by providing relief from the obligation to pay royalties on certain federal leases. Deep water leases issued in certain years by the Minerals Management Service (the MMS) have contained price thresholds, such that if the market prices for oil or natural gas exceeded the thresholds for a given year, royalty relief would not be granted for that year. Deep water leases issued in 1998 and 1999 did not include price thresholds. The MMS in 2006 informed Devon and other oil and gas companies that the omission of price thresholds from these leases was an error on its part and was not its intention. Accordingly, the MMS invited Devon and the other affected oil and gas producers to renegotiate the terms and conditions of the 1998 and 1999 leases to add price threshold provisions to the lease agreements for periods after October 1, 2006. Devon has since had several discussions with MMS representatives on this issue, but has not yet entered into renegotiated leases.

The U.S. House of Representatives in January 2007 passed legislation that would require companies to renegotiate the 1998 and 1999 leases as a condition of securing future federal leases. If this legislation were to become law, it would require price thresholds to be effective in the renegotiated 1998 and 1999 leases effective October 1, 2006. Although Devon has not yet signed renegotiated leases, it has accrued in its 2006 consolidated financial statements approximately $6 million for royalties that would be due if price thresholds were added to its 1998 and 1999 leases effective October 1, 2006.

Equatorial Guinea Investigation

The SEC has been conducting an inquiry into payments made to the government of Equatorial Guinea and to officials and persons affiliated with officials of the government of Equatorial Guinea. On August 9, 2005, Devon received a subpoena issued by the SEC pursuant to a formal order of investigation. Devon has cooperated fully with the SEC s requests for information in this inquiry. After responding in 2005 to such requests for information, Devon has not been contacted by the SEC. In the event that Devon receives any further inquiries, Devon will work with the SEC in connection with its investigation.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Hurricane Contingencies

Historically, Devon maintained a comprehensive insurance program that included coverage for physical damage to its offshore facilities caused by hurricanes. Devon s historical insurance program also included substantial business interruption coverage which Devon is utilizing to recover costs associated with the suspended production related to hurricanes that struck the Gulf of Mexico in the third quarter of 2005. Under the terms of this insurance program, Devon was entitled to be reimbursed for the portion of production suspended longer than forty-five days, subject to upper limits to oil and natural gas prices. Also, the terms of the insurance include a standard, per-event deductible of $1 million for offshore losses as well as a $15 million aggregate annual deductible.

Based on current estimates of physical damage and the anticipated length of time Devon will have production suspended, Devon expects its policy recoveries will exceed repair costs and deductible amounts. This expectation is based upon several variables, including the $467 million received in the third quarter of 2006 as a full settlement of the amount due from Devon s primary insurers. As of December 31, 2006, $154 million of these proceeds had been utilized as reimbursement of past repair costs and deductible amounts. The remaining proceeds of $313 million will be utilized as reimbursement of Devon s anticipated future repair costs. Devon has not yet received any settlements related to claims filed with its secondary insurers.

Should Devon s total policy recoveries, including the partial settlements already received from Devon s primary insurers, exceed all repair costs and deductible amounts, such excess will be recognized as other income in the statement of operations in the period in which such determination can be made.

The policy underlying the insurance program terms described above expired on August 31, 2006. During the third quarter of 2006, Devon was able to re-establish a comprehensive insurance program that includes business interruption and physical damage coverage for its business. However, due to significant changes in the marketplace, Devon was only able to obtain a *de minimis* amount of coverage for any damage that may be caused by named windstorms in the Gulf of Mexico. Devon has not experienced any losses under this new insurance arrangement through December 31, 2006.

Other Matters

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

Commitments

Devon has certain drilling and facility obligations under contractual agreements with third party service providers to procure drilling rigs and other related services for developmental and exploratory drilling and facilities construction. Included in the $3.0 billion total of Drilling and Facility Obligations in the table below is $1.9 billion which relates to long-term contracts for three deepwater drilling rigs and certain other contracts for onshore drilling and facility obligations in which drilling or facilities construction has not commenced. The $1.9 billion represents the gross commitment under these contracts. Devon s ultimate payment for these commitments will be reduced by the amounts billed to its partners when net working interests are ultimately determined. Payments for these commitments, net of amounts billed to partners, will be capitalized as a component of oil and gas properties.

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $36 million, $35 million and $49 million in 2006, 2005 and 2004, respectively.

Devon assumed two offshore platform spar leases through the 2003 Ocean merger. The spars are being used in the development of the Nansen and Boomvang fields in the Gulf of Mexico. The Boomvang field was divested as part of the 2005 property divestiture program. The Nansen operating lease is for a 20-year term and contains various options whereby Devon may purchase the lessors interests in the spar. Total rental expense included in lease operating expenses under both the Nansen and Boomvang operating leases was $12 million, $14 million and $17 million in 2006, 2005 and 2004, respectively. Devon has guaranteed that the Nansen spar will have a residual value at the end of the operating lease equal to at least 10% of the fair value of the spar at the inception of the lease. The total guaranteed value is $14 million in 2022. However, such amount may be reduced under the terms of the lease agreement. As a result of the sale of the Boomvang field, Devon is subleasing the Boomvang Spar. If the sublessee were to default on its obligation, Devon would continue to be obligated to pay the periodic lease payments and any guaranteed value required at the end of the term.

Devon has a floating, production, storage and offloading facility (FPSO) that is being used in the Panyu project offshore China and is being leased under operating lease arrangements. This lease expires in September 2009. Devon was also leasing an FPSO that is being used in the Zafiro field offshore Equatorial Guinea. Devon and the other working interest owners purchased this FPSO in the fourth quarter of 2005. Total rental expense included in lease operating expenses under both the China and Equatorial Guinea operating leases was $9 million, $19 million and $20 million in 2006, 2005 and 2004, respectively.

The following is a schedule by year of future minimum payments for drilling and facility obligations, firm transportation agreements and leases that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 2006:

Year Ending December 31,	Drilling and Facility Obligations	Firm Transportation Agreements	Office and Equipment Leases	Spar Leases	FPSO Leases
		(In millions)			
2007	$ 886	123	48	11	21
2008	524	92	44	11	31
2009	613	81	37	11	29
2010	480	61	29	11	23
2011	364	45	26	11	23
Thereafter	126	172	31	141	57
Total payments	$ 2,993	574	215	196	184

9. Share-Based Compensation

On June 8, 2005, Devon s stockholders adopted the 2005 Long-Term Incentive Plan which expires on June 8, 2013. Devon s stockholders adopted certain amendments to this plan on June 7, 2006. This plan, as amended, authorizes the Compensation Committee, which consists of non-management members of Devon s Board of Directors, to grant nonqualified and incentive stock options, restricted stock awards, Canadian restricted stock units, performance units, performance bonuses, stock appreciation rights and cash-out rights to eligible employees. The plan also authorizes the grant of nonqualified stock options, restricted stock awards and stock appreciation rights to directors. A total of 32 million shares of Devon common stock have been

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

reserved for issuance pursuant to the plan. To calculate shares issued under the plan, options granted represent one share and other awards represent 2.2 shares.

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

As discussed in Note 1, on January 1, 2006, Devon changed its method of accounting for share-based compensation from the APB No. 25 intrinsic value accounting method to the fair value recognition provisions of SFAS No. 123(R). The following table presents the effects of share-based compensation included in Devon s accompanying statement of operations for the years ended December 31, 2006, 2005 and 2004.

	2006	2005	2004
		(In millions)	
Gross general and administrative expense	$ 91	29	12
Share-based compensation expense capitalized pursuant to the full cost method of accounting for oil and gas properties	$ 26		
Related income tax benefit	$ 23	11	5

Stock Options

Under Devon s 2005 Long-Term Incentive Plan, the exercise price of stock options granted may not be less than the estimated fair market value of the stock at the date of grant. In addition, options granted are exercisable during a period established for each grant, which period may not exceed eight years from the date of grant. The recipient must pay the exercise price in cash or in common stock, or a combination thereof, at the time that the option is exercised. Options granted generally have a vesting period that ranges from three to four years.

The fair value of stock options on the date of grant is expensed over the applicable vesting period. Devon estimates the fair values of stock options granted using a Black-Scholes option valuation model, which requires Devon to make several assumptions. The volatility of Devon s common stock is based on the historical volatility of the market price of Devon s common stock over a period of time equal to the expected term of the option and ending on the grant date. The dividend yield is based on Devon s historical and current yield in effect at the date of grant. The risk-free interest rate is based on the zero-coupon U.S. Treasury yield for the expected term of the option at the date of grant. The expected term of the options is based on historical exercise and termination experience for various groups of employees and directors. Each group is determined based on the similarity of their historical exercise and termination behavior.

The following table presents a summary of the grant-date fair values of stock options granted and the related assumptions for the years ended December 31, 2006, 2005 and 2004. All such amounts represent the weighted-average amounts for each year.

	2006	2005 (In millions)	2004
Grant-date fair value	$ 22.41	$ 19.65	$ 10.32
Volatility factor	32.2%	31.0%	32.2%
Dividend yield	0.5%	0.6%	0.5%
Risk-free interest rate	5.7%	4.4%	3.2%
Expected term (in years)	4.0	4.2	4.0

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents a summary of Devon s outstanding stock options as of December 31, 2006, including changes during the year then ended.

	Options (In thousands)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (In Years)	Aggregate Intrinsic Value (In millions)
Outstanding at December 31, 2005	16,732	$ 32.74		
Granted	1,874	$ 70.00		
Exercised	(2,846)	$ 25.41		
Forfeited	(377)	$ 49.16		
Outstanding at December 31, 2006	15,383	$ 38.24	4.1	$ 450
Vested and expected to vest at December 31, 2006	14,952	$ 37.51	4.1	$ 448
Exercisable at December 31, 2006	11,034	$ 29.44	3.8	$ 416

The aggregate intrinsic value of stock options that were exercised during 2006, 2005 and 2004 was $119 million, $149 million and $168 million, respectively. As of December 31, 2006, Devon s unrecognized compensation cost related to unvested stock options was $77 million. Such cost is expected to be recognized over a weighted-average period of 2.4 years.

Restricted Stock Awards and Units

Under Devon s 2005 Long-Term Incentive Plan, restricted stock awards and units are subject to the terms, conditions, restrictions and/or limitations, if any, that the Compensation Committee deems appropriate, including restrictions on continued employment. Generally, restricted stock awards and units vest over a minimum restriction period of at least three years from the date of grant. During the vesting period, recipients of restricted stock awards receive dividends which are not subject to restrictions or other limitations. The fair value of restricted stock awards and units on the date of grant is expensed over the applicable vesting period. Devon estimates the fair values of restricted stock awards and units as the closing price of Devon s common stock on the grant date of the award or unit.

The following table presents a summary of Devon s unvested restricted stock awards as of December 31, 2006, including changes during the year then ended.

	Weighted

	Restricted Stock Awards (In thousands)	Average Grant-Date Fair Value
Unvested at December 31, 2005	3,417	$ 46.80
Granted	3,091	$ 65.68
Vested	(1,156)	$ 42.58
Forfeited	(190)	$ 47.54
Unvested at December 31, 2006	5,162	$ 58.35

The aggregate fair value of restricted stock awards that vested during 2006, 2005 and 2004 was $82 million, $51 million and $15 million, respectively. As of December 31, 2006, Devon s unrecognized

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

compensation cost related to unvested restricted stock awards and units was $253 million. Such cost is expected to be recognized over a weighted-average period of 2.9 years.

10. Reduction of Carrying Value of Oil and Gas Properties

During 2006 and 2005, Devon reduced the carrying value of certain of its oil and gas properties due to full cost ceiling limitations and unsuccessful exploratory activities. A summary of these reductions and additional discussion is provided below.

	Year Ended December 31, 2006		2005	
	Gross	Net of Taxes	Gross	Net of Taxes
	(In millions)			
Unsuccessful exploratory reductions:				
Nigeria	$ 85	85		
Brazil	16	16	42	42
Angola			170	119
Ceiling test reduction Russia	20	10		
Total	$ 121	111	212	161

2006 Reductions

Devon has committed to drill four wells in Nigeria. The first two wells were unsuccessful. After drilling the second unsuccessful well in the first quarter of 2006, Devon determined that the capitalized costs related to these two wells should be impaired. Therefore, in the first quarter of 2006, Devon recognized an $85 million impairment of its investment in Nigeria equal to the costs to drill the two dry holes and a proportionate share of block-related costs. There was no tax benefit related to this impairment.

During the second quarter of 2006, Devon drilled two unsuccessful exploratory wells in Brazil and determined that the capitalized costs related to these two wells should be impaired. Therefore, in the second quarter of 2006, Devon recognized a $16 million impairment of its investment in Brazil equal to the costs to drill the two dry holes and a proportionate share of block-related costs. There was no tax benefit related to this impairment. The two wells were unrelated to Devon s Polvo development project in Brazil.

As a result of a decline in projected future net cash flows, the carrying value of Devon s Russian properties exceeded the full cost ceiling by $10 million at the end of the third quarter of 2006. Therefore, Devon recognized a $20 million reduction of the carrying value of its oil and gas properties in Russia, offset by a $10 million deferred income tax benefit.

2005 Reductions

Devon s interests in Angola were acquired through the 2003 Ocean Energy merger. Devon s Angolan drilling program discovered no proven reserves. After drilling three unsuccessful wells in the fourth quarter of 2005, Devon determined that all of the Angolan capitalized costs should be impaired.

Prior to the fourth quarter of 2005, Devon was capitalizing the costs of previous unsuccessful efforts in Brazil pending the determination of whether proved reserves would be recorded in Brazil. Devon has been successful in its drilling efforts on block BM-C-8 in Brazil and is currently developing the Polvo project on this block. The ultimate value of the Polvo project is expected to be in excess of the sum of its related costs, plus the costs of the previous unrelated unsuccessful efforts in Brazil which were capitalized. However, the Polvo proved reserves will be recorded over a period of time. At the end of 2005, it was expected that a small

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

initial portion of the proved reserves ultimately expected at Polvo would be recorded in 2006. Based on preliminary estimates developed in the fourth quarter of 2005, the value of this initial partial booking of proved reserves was not sufficient to offset the sum of the related proportionate Polvo costs plus the costs of the previous unrelated unsuccessful efforts. Therefore, Devon determined that the prior unsuccessful costs unrelated to the Polvo project should be impaired. These costs totaled approximately $42 million. There was no tax benefit related to this Brazilian impairment.

11. Other Income

The components of other income include the following:

	Year Ended December 31, 2006	2005	2004
	(In millions)		
Interest and dividend income	$ 100	95	45
Net gain on sales of non-oil and gas property and equipment	6	150	33
Loss on derivative financial instruments		(48)	
Gains from changes in foreign exchange rates		2	23
Other	9	(1)	25
Total	$ 115	198	126

12. Income Taxes

At December 31, 2006, 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. For financial purposes, the tax effects of these carryforwards have been recognized as reductions to the net deferred tax liability at December 31, 2006.

Jurisdiction	Years of Expiration	Carryforward Amounts (In millions)
Various U.S. states	2007 - 2022	$ 110
Canada	2008 - 2027	$ 143
Brazil	Indefinite	$ 31

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The earnings from continuing operations before income taxes and the components of income tax expense (benefit) for the years 2006, 2005 and 2004 were as follows:

	Year Ended December 31,		
	2006	2005	2004
	(In millions)		
Earnings from continuing operations before income taxes:			
U.S.	$ 2,435	3,254	2,264
Canada	751	899	598
International	826	352	414
Total	$ 4,012	4,505	3,276
Current income tax expense:			
U.S. federal	$ 292	735	346
Various states	7	26	10
Canada	143	106	49
International	377	351	320
Total current tax expense	819	1,218	725
Deferred income tax expense (benefit):			
U.S. federal	456	271	246
Various states	77	(18)	27
Canada	(105)	217	149
International	(58)	(82)	(52)
Total deferred tax expense	370	388	370
Total income tax expense	$ 1,189	1,606	1,095

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

Total income tax expense differed from the amounts computed by applying the U.S. federal income tax rate to earnings from continuing operations before income taxes as a result of the following:

	Year Ended December 31,		
	2006	2005	2004
	(In millions)		

Expected income tax expense based on U.S. statutory tax rate of 35%	$ 1,404	1,577	1,146
Effect of Canadian tax rate reductions	(243)	(14)	(36)
U.S. manufacturing deduction	(12)	(25)	
Repatriation of Canadian earnings		28	
State income taxes	55	6	20
Taxation on foreign operations	(22)	30	(35)
Other	7	4	
Total income tax expense	$ 1,189	1,606	1,095

In 2006, 2005 and 2004, deferred income taxes were reduced $243 million, $14 million and $36 million, respectively, due to Canadian statutory rate reductions that were enacted in each such year.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In 2006 and 2005, income taxes were reduced $12 million and $25 million, respectively, due to a new U.S. tax deduction for companies with domestic production activities, including oil and gas extraction.

In 2006, deferred income taxes increased $39 million due to the effect of a new income-based tax enacted by the state of Texas that replaces a previous franchise tax. The new tax is effective January 1, 2007. The $39 million increase is included in 2006 state income taxes in the above table.

In 2005, Devon recognized $28 million of taxes related to its repatriation of $545 million to the U.S. The cash was repatriated due to tax legislation that allowed qualifying companies to repatriate cash from foreign operations at a reduced income tax rate. Substantially all of the cash repatriated by Devon in 2005 related to earnings of its Canadian subsidiary.

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities at December 31, 2006 and 2005 are presented below:

	December 31, 2006	December 31, 2005
	(In millions)	
Deferred tax assets:		
Net operating loss carryforwards	$ 35	148
Minimum tax credit carryforwards		18
Fair value of derivative financial instruments	97	52
Asset retirement obligations	270	271
Pension benefit obligations	81	49
Insurance proceeds	113	
Other	108	102
Total deferred tax assets	704	640
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	(5,743)	(5,406)
Chevron Corporation common stock	(326)	(247)
Long-term debt	(148)	(168)
Other	(35)	(35)
Total deferred tax liabilities	(6,252)	(5,856)
Net deferred tax liability	$ (5,548)	(5,216)

As shown in the above table, Devon has recognized $704 million of deferred tax assets as of December 31, 2006. Such amount includes $35 million from various carryforwards available to offset future income taxes. The carryforwards include state net operating loss carryforwards which expire primarily between 2007 and 2022, Canadian net operating loss carryforwards which expire primarily between 2008 and 2027, and Brazilian net operating loss 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 2007 and 2010. 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

13. Discontinued Operations

Egypt

On November 14, 2006, Devon announced its plans to divest its operations in Egypt. Pursuant to accounting rules for discontinued operations, Devon has classified all 2006 and prior period amounts related to its operations in Egypt as discontinued operations. Devon anticipates completing the sale of its Egyptian assets during the first half of 2007. As of December 31, 2006, Devon has not recorded any gain or loss associated with this planned sale.

Revenues related to Devon s operations in Egypt totaled $118 million, $119 million and $133 million during 2006, 2005 and 2004, respectively. The following table presents the main classes of assets and liabilities associated with Devon s operations in Egypt as of December 31, 2006 and 2005.

	As of December 31,	
	2006	2005
	(In millions)	
Assets:		
Cash	$ 17	13
Accounts receivable	32	36
Other current assets	32	17
Current assets	$ 81	66
Long-term assets property and equipment, net of accumulated depreciation, depletion and amortization	$ 185	217
Liabilities:		
Current liabilities accounts payable trade	$ 5	19
Asset retirement obligation, long-term	$ 9	8
Deferred income taxes	15	31
Other liabilities	1	1
Long-term liabilities	$ 25	40

West Africa (Subsequent Event)

On January 23, 2007 Devon announced its plans to divest its operations in West Africa. Pursuant to accounting rules for discontinued operations, Devon has not classified the assets, liabilities or operating results of its operations in West Africa as discontinued operations as of December 31, 2006. However, such amounts will be classified as discontinued operations beginning with the first quarter of 2007. Devon anticipates completing the sale of its West African assets during the third quarter of 2007. As of December 31, 2006, Devon has not recorded any gain or loss associated with this planned sale.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents the main classes of assets and liabilities associated with Devon s operations in West Africa as of December 31, 2006 and 2005.

	As of December 31, 2006	2005
	(In millions)	
Assets:		
Cash	$ 47	62
Accounts receivable	69	190
Other current assets	35	31
Current assets	$ 151	283
Long-term assets property and equipment, net of accumulated depreciation, depletion and amortization	$ 1,434	1,515
Liabilities:		
Accounts payable trade	$ 43	64
Income taxes payable	115	101
Current portion of asset retirement obligation	8	
Accrued expenses and other current liabilities	2	
Current liabilities	$ 168	165
Asset retirement obligation, long-term	$ 29	24
Deferred income taxes	360	397
Other liabilities	15	15
Long-term liabilities	$ 404	436

14. Segment Information

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

Following is certain financial information regarding Devon s segments for 2006, 2005 and 2004. The revenues reported are all from external customers.

	U.S.	Canada	International	Total
		(In millions)		
As of December 31, 2006:				
Current assets	$ 1,307	616	1,289	3,212
Property and equipment, net of accumulated depreciation, depletion and amortization	15,253	6,929	2,413	24,595
Goodwill	3,053	2,585	68	5,706
Other assets	1,289	35	226	1,550
Total assets	$ 20,902	10,165	3,996	35,063
Current liabilities	$ 3,693	569	383	4,645
Long-term debt	2,594	2,974		5,568
Asset retirement obligation, long-term	387	360	86	833
Other liabilities	864	16	45	925
Deferred income taxes	3,351	1,831	468	5,650
Stockholders equity	10,013	4,415	3,014	17,442
Total liabilities and stockholders equity	$ 20,902	10,165	3,996	35,063

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	U.S.	Canada	International	Total
		(In millions)		
Year Ended December 31, 2006:				
Revenues:				
Oil sales	$ 1,218	603	1,384	3,205
Gas sales	3,445	1,456	31	4,932
NGL sales	548	201		749
Marketing and midstream revenues	1,641	31	20	1,692
Total revenues	6,852	2,291	1,435	10,578
Expenses and other income, net:				
Lease operating expenses	813	543	132	1,488
Production taxes	235	7	99	341
Marketing and midstream operating costs and expenses	1,226	10	8	1,244
Depreciation, depletion and amortization of oil and gas properties	1,311	644	311	2,266
Depreciation and amortization of non-oil and gas properties	154	18	4	176
Accretion of asset retirement obligation	25	21	3	49
General and administrative expenses	316	92	(11)	397
Interest expense	199	222		421
Change in fair value of derivative financial instruments	181	(3)		178
Reduction of carrying value of oil and gas properties			121	121
Other income, net	(43)	(14)	(58)	(115)
Total expenses and other income, net	4,417	1,540	609	6,566
Earnings from continuing operations before income tax expense	2,435	751	826	4,012
Income tax expense (benefit):				
Current	299	143	377	819
Deferred	533	(105)	(58)	370
Total income tax expense	832	38	319	1,189
Earnings from continuing operations	1,603	713	507	2,823
Discontinued operations:				
Earnings from discontinued operations before income taxes			22	22
Income tax benefit			(1)	(1)
Earnings from discontinued operations			23	23

Net earnings	1,603	713	530	2,846
Preferred stock dividends	10			10
Net earnings applicable to common stockholders	$ 1,593	713	530	2,836
Capital expenditures	$ 5,814	1,670	609	8,093

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	U.S.	Canada	International	Total
		(In millions)		
As of December 31, 2005:				
Current assets	$ 2,042	1,182	982	4,206
Property and equipment, net of accumulated depreciation, depletion and amortization	10,856	5,877	2,178	18,911
Goodwill	3,056	2,581	68	5,705
Other assets	1,213	17	221	1,451
Total assets	$ 17,167	9,657	3,449	30,273
Current liabilities	$ 1,736	925	273	2,934
Long-term debt	2,986	2,971		5,957
Asset retirement obligation, long-term	320	261	29	610
Other liabilities	467	12	57	536
Deferred income taxes	2,864	2,008	502	5,374
Stockholders equity	8,794	3,480	2,588	14,862
Total liabilities and stockholders equity	$ 17,167	9,657	3,449	30,273
Year Ended December 31, 2005:				
Revenues:				
Oil sales	$ 1,062	353	944	2,359
Gas sales	3,929	1,814	41	5,784
NGL sales	484	196	7	687
Marketing and midstream revenues	1,780	12		1,792
Total revenues	7,255	2,375	992	10,622
Expenses and other income, net:				
Lease operating expenses	710	498	116	1,324
Production taxes	273	6	56	335
Marketing and midstream operating costs and expenses	1,336	6		1,342
Depreciation, depletion and amortization of oil and gas properties	1,137	570	274	1,981
Depreciation and amortization of non-oil and gas properties	141	14	5	160
Accretion of asset retirement obligation	25	16	2	43
General and administrative expenses	245	59	(13)	291
Interest expense	224	309		533
Change in fair value of derivative financial instruments	86	8		94
Reduction of carrying value of oil and gas properties			212	212
Other income, net	(176)	(10)	(12)	(198)

Total expenses and other income, net	4,001	1,476	640	6,117
Earnings from continuing operations before income tax expense	3,254	899	352	4,505
Income tax expense (benefit):				
Current	761	106	351	1,218
Deferred	253	217	(82)	388
Total income tax expense	1,014	323	269	1,606
Earnings from continuing operations	2,240	576	83	2,899
Discontinued operations:				
Earnings from discontinued operations before income taxes			46	46
Income tax expense			15	15
Earnings from discontinued operations			31	31
Net earnings	2,240	576	114	2,930
Preferred stock dividends	10			10
Net earnings applicable to common stockholders	$ 2,230	576	114	2,920
Capital expenditures	$ 2,200	1,707	308	4,215

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	U.S.	Canada	International	Total
		(In millions)		
Year Ended December 31, 2004:				
Revenues:				
Oil sales	$ 976	299	824	2,099
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	864	9,086
Expenses and other income, net:				
Lease operating expenses	714	438	107	1,259
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	313	2,077
Depreciation and amortization of non-oil and gas properties	130	14	4	148
Accretion of asset retirement obligation	27	15	2	44
General and administrative expenses	221	56		277
Interest expense	197	278		475
Change in fair value of derivative financial instruments	63	(1)		62
Other income, net	(81)	(39)	(6)	(126)
Total expenses and other income, net	4,066	1,294	450	5,810
Earnings before income tax expense	2,264	598	414	3,276
Income tax expense (benefit):				
Current	356	49	320	725
Deferred	273	149	(52)	370
Total income tax expense	629	198	268	1,095
Earnings from continuing operations	1,635	400	146	2,181
Discontinued operations:				
Earnings from discontinued operations before income taxes			17	17
Income tax expense			12	12
Earnings from discontinued operations			5	5
Net earnings	1,635	400	151	2,186
Preferred stock dividends	10			10

Net earnings applicable to common stockholders	$ 1,625	400	151	2,176
Capital expenditures	$ 1,674	979	279	2,932

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. Supplemental Information on Oil and Gas Operations (Unaudited)

The following supplemental unaudited information regarding the oil and gas activities of Devon is presented pursuant to the disclosure requirements promulgated by the Securities and Exchange Commission and SFAS No. 69, *Disclosures About Oil and Gas Producing Activities.* This supplemental information excludes amounts for all periods presented related to Devon s discontinued operations in Egypt.

Costs Incurred

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

	Total Year Ended December 31,		
	2006	2005	2004
	(In millions)		
Property acquisition costs:			
Proved properties	$ 1,113	54	38
Unproved properties	1,485	347	141
Exploration costs	973	890	714
Development costs	4,151	2,787	1,917
Costs incurred	$ 7,722	4,078	2,810

	Domestic Year Ended December 31,		
	2006	2005	2004
	(In millions)		
Property acquisition costs:			
Proved properties	$ 1,066	5	27
Unproved properties	1,366	106	75
Exploration costs	547	422	335
Development costs	2,558	1,597	1,163
Costs incurred	$ 5,537	2,130	1,600

Canada

	Year Ended December 31,		
	2006	2005	2004
	(In millions)		
Property acquisition costs:			
Proved properties	$ 23	49	11
Unproved properties	70	239	52
Exploration costs	217	361	272
Development costs	1,244	1,020	625
Costs incurred	$ 1,554	1,669	960

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	International Year Ended December 31, (In millions)		
	2006	2005	2004
Property acquisition costs:			
Proved properties	$ 24		
Unproved properties	49	2	14
Exploration costs	209	107	107
Development costs	349	170	129
Costs incurred	$ 631	279	250

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 $269 million, $181 million and $166 million in the years 2006, 2005 and 2004, 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 in each of the years 2006, 2005 and 2004.

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, (In millions, except per equivalent barrel amounts)		
	2006	2005	2004
Oil, gas and NGL sales	$ 8,886	8,830	7,385
Production and operating expenses	(1,829)	(1,659)	(1,514)
Depreciation, depletion and amortization	(2,266)	(1,981)	(2,077)
Accretion of asset retirement obligation	(49)	(43)	(44)
General and administrative expenses	(162)	(107)	(104)
Reduction of carrying value of oil and gas properties	(121)	(212)	
Income tax expense	(1,448)	(1,830)	(1,342)

Results of operations	$ 3,011	2,998	2,304
Depreciation, depletion and amortization per Boe	$ 10.59	8.86	8.41

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Domestic Year Ended December 31, (In millions, except per equivalent barrel amounts)		
	2006	2005	2004
Oil, gas and NGL sales	$ 5,211	5,475	4,642
Production and operating expenses	(1,048)	(983)	(934)
Depreciation, depletion and amortization	(1,311)	(1,137)	(1,242)
Accretion of asset retirement obligation	(26)	(25)	(27)
General and administrative expenses	(115)	(84)	(75)
Income tax expense	(996)	(1,145)	(807)
Results of operations	$ 1,715	2,101	1,557
Depreciation, depletion and amortization per Boe	$ 9.89	8.35	8.23

	Canada Year Ended December 31, (In millions, except per equivalent barrel amounts)		
	2006	2005	2004
Oil, gas and NGL sales	$ 2,260	2,363	1,879
Production and operating expenses	(550)	(504)	(443)
Depreciation, depletion and amortization	(644)	(570)	(522)
Accretion of asset retirement obligation	(21)	(16)	(15)
General and administrative expenses	(29)	(20)	(16)
Income tax expense	(144)	(426)	(275)
Results of operations	$ 872	827	608
Depreciation, depletion and amortization per Boe	$ 11.17	9.20	8.00

	International Year Ended December 31, (In millions, except per equivalent barrel amounts)		
	2006	2005	2004

Oil, gas and NGL sales	$ 1,415	992	864
Production and operating expenses	(231)	(172)	(137)
Depreciation, depletion and amortization	(311)	(274)	(313)
Accretion of asset retirement obligation	(2)	(2)	(2)
General and administrative expenses	(18)	(3)	(13)
Reduction of carrying value of oil and gas properties	(121)	(212)	
Income tax expense	(308)	(259)	(260)
Results of operations	$ 424	70	139
Depreciation, depletion and amortization per Boe	$ 13.03	10.73	10.13

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In 2006, 2005 and 2004, the Canadian income tax amounts in the tables above were reduced by $243 million, $14 million and $36 million, respectively, due to statutory rate reductions that were enacted in each such year.

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 2006, 2005 and 2004.

	2006		2005		2004	
	Prepared	**Audited**	**Prepared**	**Audited**	**Prepared**	**Audited**
Domestic	7%	81%	9%	79%	16%	61%
Canada	46%	39%	46%	26%	22%	
International	99%		98%		98%	
Total	28%	61%	31%	54%	28%	35%

Prepared reserves are those 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.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2006. Additional discussion of the significant proved reserve changes follows the tables below.

	Oil (MMBbls)	Gas (Bcf)	Total Natural Gas Liquids (MMBbls)	Total (MMBoe)
Proved reserves as of December 31, 2003	646	7,316	209	2,074
Revisions due to prices	(82)	39	1	(75)
Revisions other than price	19	29	21	45
Extensions and discoveries	76	988	25	266
Purchase of reserves	1	14		3
Production	(74)	(891)	(24)	(247)
Sale of reserves	(1)	(2)		(1)
Proved reserves as of December 31, 2004	585	7,493	232	2,065
Revisions due to prices	(14)	78	4	3
Revisions other than price	21	(2)	16	37
Extensions and discoveries	166	1,220	30	400
Purchase of reserves	2	10		4
Production	(62)	(827)	(24)	(224)
Sale of reserves	(58)	(676)	(12)	(183)
Proved reserves as of December 31, 2005	640	7,296	246	2,102
Revisions due to prices	(21)	(89)	(7)	(44)
Revisions other than price	5	(106)	5	(6)
Extensions and discoveries	139	1,491	45	433
Purchase of reserves		584	9	106
Production	(55)	(815)	(23)	(214)
Sale of reserves		(5)		(1)
Proved reserves as of December 31, 2006	708	8,356	275	2,376
Proved developed reserves as of:				
December 31, 2003	392	5,980	179	1,568
December 31, 2004	400	6,219	204	1,640
December 31, 2005	355	6,111	216	1,589
December 31, 2006	358	6,518	229	1,674

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Oil (MMBbls)	Gas (Bcf)	Domestic Natural Gas Liquids (MMBbls)	Total (MMBoe)
Proved reserves as of December 31, 2003	212	4,884	161	1,187
Revisions due to prices	5	8	1	8
Revisions other than price	2	62	23	35
Extensions and discoveries	16	578	16	129
Purchase of reserves		8		1
Production	(31)	(602)	(19)	(151)
Sale of reserves	(1)	(2)		(1)
Proved reserves as of December 31, 2004	203	4,936	182	1,208
Revisions due to prices	6	58	3	19
Revisions other than price	2	238	19	61
Extensions and discoveries	16	793	20	169
Purchase of reserves				
Production	(25)	(555)	(18)	(136)
Sale of reserves	(29)	(306)	(9)	(89)
Proved reserves as of December 31, 2005	173	5,164	197	1,232
Revisions due to prices		(110)	(3)	(22)
Revisions other than price		(11)	6	5
Extensions and discoveries	16	1,298	43	274
Purchase of reserves		580	9	105
Production	(19)	(566)	(19)	(132)
Sale of reserves				
Proved reserves as of December 31, 2006	170	6,355	233	1,462
Proved developed reserves as of:				
December 31, 2003	171	3,935	136	964
December 31, 2004	168	4,105	161	1,014
December 31, 2005	149	4,343	175	1,049
December 31, 2006	147	4,916	196	1,163

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Canada			
	Oil (MMBbls)	Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total (MMBoe)
Proved reserves as of December 31, 2003	148	2,297	48	579
Revisions due to prices	(43)	32		(38)
Revisions other than price	5	(46)	(2)	(5)
Extensions and discoveries	50	410	9	127
Purchase of reserves	1	6		2
Production	(14)	(279)	(5)	(65)
Sale of reserves				
Proved reserves as of December 31, 2004	147	2,420	50	600
Revisions due to prices		22	1	4
Revisions other than price	2	(242)	(3)	(41)
Extensions and discoveries	144	427	10	225
Purchase of reserves	2	10		4
Production	(13)	(261)	(6)	(62)
Sale of reserves	(29)	(370)	(3)	(94)
Proved reserves as of December 31, 2005	253	2,006	49	636
Revisions due to prices	(19)	23	(4)	(20)
Revisions other than price	(1)	(84)	(1)	(16)
Extensions and discoveries	109	193	2	145
Purchase of reserves		4		1
Production	(13)	(241)	(4)	(58)
Sale of reserves		(5)		(1)
Proved reserves as of December 31, 2006	329	1,896	42	687
Proved developed reserves as of:				
December 31, 2003	123	1,964	43	493
December 31, 2004	123	2,043	43	507
December 31, 2005	103	1,708	41	429
December 31, 2006	112	1,560	33	405

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	International(1)			
	Oil (MMBbls)	Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total (MMBoe)
Proved reserves as of December 31, 2003	286	135		308
Revisions due to prices	(44)	(1)		(45)
Revisions other than price	12	13		15
Extensions and discoveries	10			10
Purchase of reserves				
Production	(29)	(10)		(31)
Sale of reserves				
Proved reserves as of December 31, 2004	235	137		257
Revisions due to prices	(20)	(2)		(20)
Revisions other than price	17	2		17
Extensions and discoveries	6			6
Purchase of reserves				
Production	(24)	(11)		(26)
Sale of reserves				
Proved reserves as of December 31, 2005	214	126		234
Revisions due to prices	(2)	(2)		(2)
Revisions other than price	6	(11)		5
Extensions and discoveries	14			14
Purchase of reserves				
Production	(23)	(8)		(24)
Sale of reserves				
Proved reserves as of December 31, 2006	209	105		227
Proved developed reserves as of:				
December 31, 2003	98	81		111
December 31, 2004	109	71		119
December 31, 2005	103	60		111
December 31, 2006	99	42		106

(1) Except for nine MMBoe of proved reserves as of December 31, 2006, the preceding International quantities of reserves are attributable to production sharing contracts with various foreign governments.

Noteworthy amounts included in the categories of proved reserve changes for the years 2006, 2005 and 2004 in the above tables include:

Extensions and Discoveries Of the 433 MMBoe of 2006 extensions and discoveries, 143 MMBoe related to the Barnett Shale area in Texas, 88 MMBoe related to the Jackfish steam-assisted gravity drainage project in Canada which is expected to begin production in 2007, 30 MMBoe related to the Carthage area in east Texas and 20 MMBoe related to the Washakie area in southern Wyoming.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The 2006 extensions and discoveries included 202 MMBoe related to additions from Devon s infill drilling activities, including 127 MMBoe related to the Barnett Shale area and 20 MMBoe related to the Lloydminster area in Canada.

Of the 400 MMBoe of 2005 extensions and discoveries, 118 MMBoe related to Jackfish, 54 MMBoe related to the Barnett Shale, and 40 MMBoe related to the Deep Basin in Canada. The 2005 extensions and discoveries included 76 MMBoe related to additions from Devon s infill drilling activities, including 19 MMBoe related to the Barnett Shale, 16 MMBoe related to Carthage and eight MMBoe related to the Permian Basin in New Mexico and west Texas.

Of the 266 MMBoe of 2004 extensions and discoveries, 32 MMBoe related to the Canadian Deep Basin, 29 MMBoe related to the Barnett Shale, and 28 MMBoe related to Carthage. The 2004 extensions and discoveries included 67 MMBoe related to additions from Devon s infill drilling activities, including 21 MMBoe related to Carthage, 12 MMBoe related to the Permian Basin and nine MMBoe related to the Barnett Shale.

Purchase of Reserves The 2006 total includes 100 MMBoe located in the Barnett Shale that was acquired in the Chief acquisition. See Note 3.

Sale of Reserves The 2005 total includes 176 MMBoe of reserves related to non-core oil and gas properties in the offshore Gulf of Mexico an onshore in the United States and Canada. See Note 3.

Standardized Measure of Discounted Future Net Cash Flows

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

	Total December 31,		
	2006	**2005**	**2004**
		(In millions)	
Future cash inflows	$ 82,354	94,132	66,595
Future costs:			
Development	(8,518)	(5,802)	(4,211)
Production	(29,408)	(25,063)	(19,513)
Future income tax expense	(13,856)	(21,425)	(13,704)
Future net cash flows	30,572	41,842	29,167
10% discount to reflect timing of cash flows	(13,999)	(18,784)	(13,555)
Standardized measure of discounted future net cash flows	$ 16,573	23,058	15,612

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Domestic December 31, 2006	2005	2004
	(In millions)		
Future cash inflows	$ 47,980	55,954	39,214
Future costs:			
Development	(4,919)	(2,954)	(2,208)
Production	(18,858)	(16,213)	(13,181)
Future income tax expense	(7,588)	(12,582)	(7,597)
Future net cash flows	16,615	24,205	16,228
10% discount to reflect timing of cash flows	(7,938)	(11,258)	(7,129)
Standardized measure of discounted future net cash flows	$ 8,677	12,947	9,099

	Canada December 31, 2006	2005	2004
	(In millions)		
Future cash inflows	$ 22,575	26,277	18,483
Future costs:			
Development	(2,395)	(1,984)	(1,353)
Production	(7,431)	(6,344)	(4,285)
Future income tax expense	(3,614)	(5,986)	(4,200)
Future net cash flows	9,135	11,963	8,645
10% discount to reflect timing of cash flows	(4,318)	(5,332)	(4,764)
Standardized measure of discounted future net cash flows	$ 4,817	6,631	3,881

	International December 31, 2006	2005	2004
	(In millions)		
Future cash inflows	$ 11,799	11,901	8,898
Future costs:			
Development	(1,204)	(864)	(650)

Production	(3,119)	(2,506)	(2,047)
Future income tax expense	(2,654)	(2,857)	(1,907)
Future net cash flows	4,822	5,674	4,294
10% discount to reflect timing of cash flows	(1,743)	(2,194)	(1,662)
Standardized measure of discounted future net cash flows	$ 3,079	3,480	2,632

Future cash inflows are computed by applying year-end prices (averaging $46.11 per barrel of oil, $5.06 per Mcf of gas and $27.63 per barrel of natural gas liquids at December 31, 2006) 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $8.5 billion of future development costs, $2.2 billion, $1.5 billion and $0.9 billion are estimated to be spent in 2007, 2008 and 2009, respectively.

Future development costs include not only development costs, but also future dismantlement, abandonment and rehabilitation costs. Included as part of the $8.5 billion of future development costs are $1.7 billion of future dismantlement, abandonment and rehabilitation costs.

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

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

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

	Year Ended December 31, (In millions)		
	2006	2005	2004
Beginning balance	$ 23,058	15,612	15,769
Oil, gas and NGL sales, net of production costs	(6,895)	(7,064)	(5,767)
Net changes in prices and production costs	(10,519)	11,767	2,027
Extensions and discoveries, net of future development costs	4,579	6,096	3,022
Purchase of reserves, net of future development costs	786	67	31
Development costs incurred during the period which reduced future development costs	1,691	778	681
Revisions of quantity estimates	(2,325)	(799)	(1,105)
Sales of reserves in place	(10)	(2,897)	(13)
Accretion of discount	3,482	2,270	2,243
Net change in income taxes	4,247	(4,691)	(1,580)
Other, primarily changes in timing and foreign exchange rates	(1,521)	1,919	304
Ending balance	$ 16,573	23,058	15,612

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. Supplemental Quarterly Financial Information (Unaudited)

Following is a summary of the unaudited interim results of operations for the years ended December 31, 2006 and 2005.

	2006				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(In millions, except per share amounts)				
Oil, gas and NGL sales	$ 2,222	2,192	2,279	2,193	8,886
Total revenues	$ 2,684	2,589	2,696	2,609	10,578
Net earnings	$ 700	859	705	582	2,846
Net earnings per common share:					
Basic	$ 1.58	1.94	1.59	1.31	6.42
Diluted	$ 1.56	1.92	1.57	1.29	6.34

	2005				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(In millions, except per share amounts)				
Oil, gas and NGL sales	$ 1,914	2,048	2,262	2,606	8,830
Total revenues	$ 2,330	2,437	2,667	3,188	10,622
Net earnings	$ 563	653	744	970	2,930
Net earnings per common share:					
Basic	$ 1.17	1.40	1.66	2.18	6.38
Diluted	$ 1.14	1.38	1.63	2.14	6.26

The first, second and third quarters of 2006 include $85 million, $16 million and $20 million, respectively, of reductions of carrying values of oil and gas properties. The after-tax effects of these amounts were $85 million (or $0.19 per share), $16 million (or $0.04 per share) and $10 million (or $0.02 per share), respectively. Also, the second quarter of 2006 included a reduction to income tax expense of $243 million (or $0.55 per share) due to statutory rate reductions in Canada and additional income tax expense of $39 million (or $0.09 per share) due to a new income-based tax enacted by the state of Texas.

The adoption of FASB Statement No. 158 in the fourth quarter of 2006 (see Note 6) had no effect on earnings from continuing operations, net earnings or related per share amounts during any of the quarterly periods in 2006.

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

Oil, gas and natural gas liquids sales for the first, second, third and fourth quarters of 2006 exclude $34 million, $27 million, $25 million and $32 million, respectively, related to discontinued operations in Egypt. Oil, gas and natural gas liquids sales for the first, second, third and fourth quarters of 2005 exclude $21 million, $31 million, $37 million and $30 million, respectively, related to discontinued operations in Egypt.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

Not Applicable.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that material information relating to Devon, including its consolidated subsidiaries, is made known to the officers who certify Devon s financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation, Devon s principal executive and principal financial officers have concluded that Devon s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective as of December 31, 2006 to ensure that the information required to be disclosed by Devon in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms.

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 12, 2007, management concluded that its internal control over financial reporting was effective as of December 31, 2006.

Management s assessment of the effectiveness of Devon s internal control over financial reporting as of December 31, 2006 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, 2006, as stated in their report which is included herein.

Changes in Internal Control Over Financial Reporting

There was no change in Devon s internal control over financial reporting during the fourth quarter of 2006 that has materially affected, or is reasonably likely to materially affect, Devon s internal control over financial reporting.

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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, 2006, 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, 2006, 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, 2006, 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, 2006 and 2005, and the related consolidated statements of operations, comprehensive income, stockholders equity and cash flows for each of the years in the three-year period ended December 31, 2006, and our report dated February 26, 2007 expressed an unqualified opinion on those consolidated financial statements. Our report refers to a change in the method of accounting for share-based payments and a change in the balance sheet recognition of defined benefit pension and other postretirement benefit plans.

KPMG LLP

Oklahoma City, Oklahoma
February 26, 2007

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Item 9B. ***Other Information***

Not applicable.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information called for by this Item 10 is incorporated hereby by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2007.

Item 11. ***Executive Compensation***

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2007.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2007.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2007.

Item 14. ***Principal Accounting Fees and Services***

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2007.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) *The following documents are filed as part of this report:*

1. Consolidated Financial Statements

Reference is made to the Index to Consolidated Financial Statements and Consolidated Financial Statement Schedules appearing at Item 8. Financial Statements and Supplementary Data in this report.

2. Consolidated Financial Statement Schedules

All financial statement schedules are omitted as they are inapplicable, or the required information has been included in the consolidated financial statements or notes thereto.

3. Exhibits

Exhibit No.	Description
2.1	Agreement and Plan of Merger, dated as of February 23, 2003, by and among Registrant, Devon NewCo Corporation, and Ocean Energy, Inc. (incorporated by reference to Registrant s Amendment No. 1 to Form S-4 Registration No. 333-103679, filed March 20, 2003).
2.2	Amended and Restated Agreement and Plan of Merger, dated as of August 13, 2001, by and among Registrant, Devon NewCo Corporation, Devon Holdco Corporation, Devon Merger Corporation, Mitchell Merger Corporation and Mitchell Energy & Development Corp. (incorporated by reference to Annex A to Registrant s Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001).
2.3	Offer to Purchase for Cash and Directors Circular dated September 6, 2001 (incorporated by reference to Registrant s and Devon Acquisition Corporation s Schedule 14D-1F filing, filed September 6, 2001).
2.4	Pre-Acquisition Agreement, dated as of August 31, 2001, between Registrant and Anderson Exploration Ltd. (incorporated by reference to Exhibit 2.2 to Registrant s Registration Statement on Form S-4, File No. 333-68694 as filed September 14, 2001).
2.5	Amendment No. One, dated as of July 11, 2000, to Agreement and Plan of Merger by and among Registrant, Devon Merger Co. and Santa Fe Snyder Corporation dated as of May 25, 2000 (incorporated by reference to Exhibit 2.1 to Registrant s Form 8-K filed on July 12, 2000).
2.6	Amended and Restated Agreement and Plan of Merger among Registrant, Devon Energy Corporation (Oklahoma), Devon Oklahoma Corporation and PennzEnergy Company dated as of May 19, 1999 (incorporated by reference to Exhibit 2.1 to Registrant s Form S-4, File No. 333-82903).
3.1	Registrant s Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 of Registrant s Form 10-K filed on March 9, 2005).
3.2	Registrant s Bylaws (incorporated by reference to Exhibit 3.2 of Registrant s Form 10-K for the year ended December 31, 2005).
4.1	Rights Agreement dated as of August 17, 1999 between Registrant and BankBoston, N.A. (incorporated by reference to Exhibit 4.2 to Registrant s Form 8-K filed on August 18, 1999).
4.2	

	Amendment to Rights Agreement, dated as of May 25, 2000, by and between Registrant and Fleet National Bank (f/k/a BankBoston, N.A.) (incorporated by reference to Exhibit 4.2 to Registrant s Form S-4 filed on June 22, 2000).
4.3	Amendment to Rights Agreement, dated as of October 4, 2001, by and between Registrant and Fleet National Bank (f/k/a Bank Boston, N.A.) (incorporated by reference to Exhibit 99.1 to Registrant s Form 8-K filed on October 11, 2001).
4.4	Amendment to Rights Agreement, dated as of August 1, 2006, by and between Registrant and UMB Bank, n.a. (incorporated by reference to Exhibit 4.4 to Registrant s Form 10-Q filed August 4, 2006).

Exhibit No.	Description
4.5	Indenture, dated as of March 1, 2002, between Registrant and The Bank of New York, as Trustee, relating to senior debt securities issuable by Registrant (the Senior Indenture) (incorporated by reference to Exhibit 4.1 of Registrant s Form 8-K filed April 9, 2002).
4.6	Supplemental Indenture No. 1, dated as of March 25, 2002, between Registrant and The Bank of New York, as Trustee, relating to the 7.95% Senior Debentures due 2032 (incorporated by reference to Exhibit 4.2 to Registrant s Form 8-K filed on April 9, 2002).
4.7	Indenture dated as of October 3, 2001, by and among Devon Financing Corporation, U.L.C. (as issuer), Registrant (as guarantor) and JP Morgan Chase Bank, formerly The Chase Manhattan Bank (as trustee), relating to the 6.875% Senior Notes due 2011 and the 7.875% Debentures due 2031 (incorporated by reference to Exhibit 4.7 to Registrant s Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).
4.8	Indenture dated as of December 15, 1992 between Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Texas Commerce Bank National Association, Trustee, relating to the 4.90% Exchangeable Senior Debentures due 2008 and the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(o) to Pennzoil Company s Form 10-K filed March 10, 1993 (SEC File No. 1-5591)).
4.9	First Supplemental Indenture dated as of January 13, 1993 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association (incorporated by reference to Exhibit 4(p) to Pennzoil Company s Form 10-K for the year ended December 31, 1992).
4.10	Second Supplemental Indenture dated as of October 12, 1993 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association, as Trustee, (incorporated by reference to Exhibit 4(i) to Pennzoil Company s Form 10-K for the year ended December 31, 1993).
4.11	Third Supplemental Indenture dated as of August 3, 1998 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and JP Morgan Chase Bank, formerly Chase Bank of Texas, National Association, as Trustee, supplements the terms of the 4.90% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(g) to PennzEnergy Company s Form 10-K for the year ended December 31, 1998).
4.12	Fourth Supplemental Indenture dated as of August 3, 1998 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and JP Morgan Chase Bank, formerly Chase Bank of Texas, National Association, as Trustee, supplements the terms of the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(h) to PennzEnergy Company s Form 10-K for the year ended December 31, 1998).
4.13	Fifth Supplemental Indenture dated as of August 17, 1999 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and JP Morgan Chase Bank, formerly Chase Bank of Texas, National Association, Trustee, supplements the terms of the 4.90% Exchangeable Senior Debentures due 2008 and the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4.7 to Registrant s Form 8-K filed on August 18, 1999).
4.14	Indenture dated as of February 15, 1986 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Mellon Bank, N.A., Trustee (incorporated by reference to Exhibit 4(a) to Pennzoil Company s Form 10-Q for the quarter ended June 30, 1986 (SEC File No. 1-5591)).
4.15	First Supplemental Indenture dated as of August 17, 1999 to Indenture dated as of February 15, 1986 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and

JP Morgan Chase Bank, formerly Chase Bank of Texas, National Association, Trustee, supplementing the terms of the 10.625% Debentures due 2001, 10.125% Debentures due 2009, 9.625% Notes due 1999 and 10.25% Debentures due 2005 (incorporated by reference to Exhibit 4.8 to Registrant s Form 8-K filed on August 18, 1999).

Exhibit No.	Description
4.16	Senior Indenture dated as of September 28, 2001 between Ocean Energy, Inc. and The Bank of New York, As Trustee (incorporated by reference to Exhibit 4.1 to Ocean Energy, Inc. s Current Report on Form 8-K filed with the SEC on September 28, 2001). Officer s Certificate establishing the terms of the 7.25% Senior Notes due 2011, including the form of global note relating thereto (incorporated by reference to Exhibit 4.2 to Ocean Energy, Inc. s Current Report on Form 8-K filed with the SEC on September 28, 2001).
4.17	Officers Certificate dated September 17, 2002 evidencing the terms of the 4.375% Senior Notes due 2007, including the form of global note relating thereto (incorporated by reference to Exhibit 4.1 to Ocean Energy, Inc. s Current Report on Form 8-K filed with the SEC on September 20, 2002).
4.18	First Supplemental Indenture, dated December 31, 2005 to Indenture dated as of September 28, 2001 among Devon OEI Operating, Inc. as Issuer, Devon Energy Production Company, L.P. as Successor Guarantor and The Bank of New York Trust Company, N.A., as Trustee, relating to the 4.375% Senior Notes due 2007 and the 7.25% Senior Notes due 2011 (incorporated by reference to Exhibit 4.19 of Registrant s Form 10-K for the year ended December 31, 2005).
4.19	Indenture dated as of July 8, 1998 among Ocean Energy, Inc., its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 10.24 to the Form 10-Q for the period ended June 30, 1998 of Ocean Energy, Inc. (Registration No. 0-25058)).
4.20	First Supplemental Indenture, dated March 30, 1999 to Indenture dated as of July 8, 1998 among Ocean Energy, Inc., its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.5 to Ocean Energy, Inc. s Form 10-Q for the period ended March 31, 1999).
4.21	Second Supplemental Indenture, dated as of May 9, 2001 to Indenture dated as of July 8, 1998 among Ocean Energy, Inc., its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 99.2 to Ocean Energy, Inc. s Current Report on Form 8-K filed with the SEC on May 14, 2001).
4.22	Third Supplemental Indenture, dated January 23, 2006 to Indenture dated as of July 8, 1998 among Devon OEI Operating, Inc. as Issuer, Devon Energy Production Company, L.P. as Successor Guarantor and Wells Fargo Bank Minnesota, National Association, as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.23 of Registrant s Form 10-K for the year ended December 31, 2005).
4.23	Senior Indenture dated September 1, 1997, among Ocean Energy, Inc. and The Bank of New York, as Trustee, and Specimen of 7.50% Senior Notes (incorporated by reference to Exhibit 4.4 to Ocean Energy s Annual Report on Form 10-K for the year ended December 31, 1997)).
4.24	First Supplemental Indenture, dated as of March 30, 1999 to Senior Indenture dated as of September 1, 1997, among Ocean Energy, Inc. and The Bank of New York, as Trustee, relating to the 7.50% Senior Notes Due 2027 (incorporated by reference to Exhibit 4.10 to Ocean Energy s Form 10-Q for the period ended March 31, 1999).
4.25	Second Supplemental Indenture, dated as of May 9, 2001 to Senior Indenture dated as of September 1, 1997, among Ocean Energy, Inc. and The Bank of New York, as Trustee, relating to the 7.50% Senior Notes (incorporated by reference to Exhibit 99.4 to Ocean Energy, Inc. s Current Report on Form 8-K filed with the SEC on May 14, 2001).
4.26	Third Supplemental Indenture, dated December 31, 2005 to Senior Indenture dated as of September 1, 1997, among Devon OEI Operating, Inc. as Issuer, Devon Energy Production Company, L.P. as Successor Guarantor, and The Bank of New York Trust Company, N.A., as Trustee, relating to the 7.50% Senior Notes (incorporated by reference to Exhibit 4.27 of Registrant s Form 10-K for the year

	ended December 31, 2005).
10.1	Amended and Restated Investor Rights Agreement, dated as of August 13, 2001, by and among Registrant, Devon Holdco Corporation, George P. Mitchell and Cynthia Woods Mitchell (attached as Annex C to the Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001).

Exhibit No.	Description
10.2	Amended and Restated Credit Agreement dated March 24, 2006, effective as of April 7, 2006, among Registrant as US Borrower, Northstar Energy Corporation and Devon Canada Corporation as Canadian Borrowers, Bank of America, N.A. as Administrative Agent, Swing Line Lender and L/C Issuer; JPMorgan Chase Bank, N.A. as Syndication Agent, Bank of Montreal D/B/A Harris Nesbitt , Royal Bank of Canada, Wachovia Bank, National Association as Co-Documentation Agents and The Other Lenders Party Hereto, Banc of America Securities L.L.C. and J.P. Morgan Securities Inc., as Joint Lead Arrangers and Book Managers for the $2.0 billion five-year revolving credit facility (incorporated by reference to Exhibit 10.1 to Registrant s Form 10-Q filed on May 4, 2006).
10.3	Devon Energy Corporation 2005 Long-Term Incentive Plan (incorporated by reference to Registrant s Form S-8 Registration No. 333-127630, filed August 17, 2005).*
10.4	First Amendment to Devon Energy Corporation 2005 Long-Term Incentive Plan (incorporated by reference to Appendix A to Registrant s Proxy Statement for the 2006 Annual Meeting of Stockholders filed on April 28, 2006).*
10.5	Devon Energy Corporation 2003 Long-Term Incentive Plan (incorporated by reference to Registrant s Form S-8 Registration No. 333-104922, filed May 1, 2003).*
10.6	Devon Energy Corporation 1997 Stock Option Plan (as amended August 29, 2000) (incorporated by reference to Exhibit A to Registrant s Proxy Statement for the 1997 Annual Meeting of Shareholders filed on April 3, 1997).*
10.7	Ocean Energy, Inc. 1998 Long Term Incentive Plan (incorporated by reference to Registrant s Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).*
10.8	Ocean Energy, Inc. 1999 Long Term Incentive Plan (incorporated by reference to Registrant s Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).*
10.9	Ocean Energy, Inc. 2001 Long Term Incentive Plan (incorporated by reference to Registrant s Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).*
10.10	Santa Fe Energy Resources Incentive Compensation Plan, as amended (incorporated by reference to Exhibit 10(a) to Santa Fe Energy Resources, Inc. s Annual Report on Form 10-K for the year ended December 31, 1998).*
10.11	Santa Fe Energy Resources 1990 Incentive Stock Compensation Plan, Third Amendment and Restatement (incorporated by reference to Exhibit 10(a) to Santa Fe Energy Resources, Inc. s Quarterly Report on Form 10-Q for the quarter ended March 31, 1996).*
10.12	Santa Fe Energy Resources, Inc. Supplemental Retirement Plan effective as of December 4, 1990 (incorporated by reference to Exhibit 10(h) to Santa Fe Energy Resources, Inc. s Annual Report on Form 10-K for the year ended December 31, 1996).*
10.13	Seagull Energy Corporation 1993 Non-Employee Directors Stock Option Plan (incorporated by reference to Registrant s Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).*
10.14	United Meridian Corporation 1994 Outside Director s Nonqualified Stock Option Plan (incorporated by reference to Registrant s Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).*
10.15	Supplemental Retirement Income Agreement among Devon Energy Corporation (Nevada), Registrant and John W. Nichols, dated March 26, 1997 (incorporated by reference to Exhibit 10.13 to Registrant s Form 10-Q for the quarter ended June 30, 1997).*
10.16	

Form of Employment Agreement between Registrant and Stephen J. Hadden, Brian J. Jennings, Robert A. Myers, J. Larry Nichols, John Richels and Darryl G. Smette, dated January 1, 2002 (incorporated by reference to Exhibit 10.26 of Registrant s Form 10-K for the year ended December 31, 2001).*

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Exhibit No.	Description
10.17	Form of Award Agreement between Registrant and Stephen J. Hadden, Marian J. Moon, J. Larry Nichols, John Richels and Darryl G. Smette for stock options granted from the 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.39 to Registrant s Form 10-Q for the quarter ended June 30, 2005).*
10.18	Form of Award Agreement between Registrant and all Non-Management Directors for stock options granted from the 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.40 to Registrant s Form 10-Q for the quarter ended June 30, 2005).*
10.19	Form of Award Agreement from the 2005 Long-Term Incentive Plan between Registrant and Stephen J. Hadden, Marian J. Moon, J. Larry Nichols, John Richels, Darryl G. Smette and all Non-Management Directors for restricted stock awards (incorporated by reference to Exhibit 10.41 to Registrant s Form 10-Q for the quarter ended June 30, 2005).*
10.20	Severance Agreement between Registrant and Danny J. Heatly, dated September 14, 2004.*
12	Statement of computations of ratios of earnings to fixed charges and to combined fixed charges and preferred stock dividends.
21	Registrant s Significant Subsidiaries.
23.1	Consent of KPMG LLP.
23.2	Consent of LaRoche Petroleum Consultants.
23.3	Consent of Ryder Scott Company, L.P.
23.4	Consent of AJM Petroleum Consultants.
31.1	Certification of J. Larry Nichols, Chief Executive Officer of Registrant, pursuant to Rule 13a-15(e) and 15d-15(e), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Danny J. Heatly, Vice President Accounting and Chief Accounting Officer (acting Chief Financial Officer) of Registrant, pursuant to Rule 13a-15(e) and 15d-15(e), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of J. Larry Nichols, Chief Executive Officer of Registrant, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Danny J. Heatly, Vice President Accounting and Chief Accounting Officer (acting Chief Financial Officer) of Registrant, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Compensatory plans or arrangements

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DEVON ENERGY CORPORATION

By: /s/ J. LARRY NICHOLS
J. Larry Nichols,
Chairman of the Board and
Chief Executive Officer

February 27, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/s/ J. Larry Nichols J. Larry Nichols	Chairman of the Board, Chief Executive Officer and Director	February 27, 2007
/s/ John Richels John Richels	President	February 27, 2007
/s/ Danny J. Heatly Danny J. Heatly	Vice President Accounting and Chief Accounting Officer (acting Chief Financial Officer)	February 27, 2007
/s/ Thomas F. Ferguson Thomas F. Ferguson	Director	February 27, 2007
/s/ Peter J. Fluor Peter J. Fluor	Director	February 27, 2007
/s/ David M. Gavrin David M. Gavrin	Director	February 27, 2007
/s/ John A. Hill John A. Hill	Director	February 27, 2007
/s/ Robert L. Howard	Director	February 27, 2007

Robert L. Howard		
/s/ William J. Johnson	Director	February 27, 2007
William J. Johnson		
/s/ Michael M. Kanovsky	Director	February 27, 2007
Michael M. Kanovsky		
/s/ J. Todd Mitchell	Director	February 27, 2007
J. Todd Mitchell		

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INDEX TO EXHIBITS

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